ORDER NO. 05-1053

ENTERED 09/29/05

**BEFORE THE PUBLIC UTILITY COMMISSION**

**OF OREGON**

UG 165/UM 1215

| | | |
|---|---|---|
| In the Matter of | ) | |
| | ) | |
| AVISTA UTILITIES | ) | |
| | ) | |
| Reflects Changes in the Cost of Purchased | ) | ORDER |
| Gas and Technical Adjustments. **(UG 165)** | ) | |
| | ) | |
| Requests Reauthorization of the PGA | ) | |
| (Purchased Gas Adjustment) Deferral | ) | |
| Mechanism. **(UM 1215)** | ) | |

DISPOSITION: TARIFF REVISIONS EFFECTIVE; WAIVER GRANTED

On August 17, 2005, Avista Utilities (Avista or company) submitted its annual gas cost tracking and technical adjustment filing, commonly known as its Purchased Gas Cost Adjustment (PGA) filing, with the Public Utility Commission of Oregon (Commission). The PGA allows Avista to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA balancing account and other deferred accounts. This filing included a proposed increase in annual revenues in Advice No. 05-03-G, docketed as UG 165, effective October 1, 2005. In a concurrent filing, docketed as UM 1215, Avista requested reauthorization of deferrals under the company's PGA mechanism. A description of the filing is found in Staff's Report, attached as Appendix A, and incorporated by reference.

On September 16, 2005, Avista filed replacement tariff sheets to correct errors found by Staff, along with a request to waive statutory notice (L.S.N.). Avista requested that all proposed tariff sheets become effective October 1, 2005.

At its public meeting on September 22, 2005, the Commission adopted Staff's recommendation to approve the L.S.N. and allow the tariff revisions of Advice No. 05-03-G to become effective with service on and after October 1, 2005. Staff also recommended reauthorization to use deferred accounting in accordance with the PGA balancing account.

## ORDER

IT IS ORDERED that:

1. Avista Utilities' request for amortization of deferred accounts, base gas cost changes, and rate changes as requested in Docket No. UG 165 is granted.

2. Avista Utilities' tariff revisions in Advice No. 05-03-G Supplemental are allowed to go into effect October 1, 2005, and the L.S.N. is approved.

3. Avista Utilities' request for reauthorization of the deferred accounting in Docket No. UM 1215, for the Purchased Gas Cost Balancing Account mechanism, for one year beginning October 1, 2005, is granted.

Made, entered, and effective SEP 29 2005.

**Lee Beyer**
Chairman

**John Savage**
Commissioner

**Ray Baum**
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

**ITEM NO. 3 & 4**

**PUBLIC UTILITY COMMISSION OF OREGON**
**STAFF REPORT**
**PUBLIC MEETING DATE: September 22, 2005**

**REGULAR** X **CONSENT** ____ **EFFECTIVE DATE** **October 1, 2005**

**DATE:** September 19, 2005

**TO:** Public Utility Commission

**FROM:** Ken Zimmerman, Lynn Kittilson and Carla Owings

**THROUGH:** Lee Sparling, Ed Busch, Bonnie Tatom and Judy Johnson

**SUBJECT:** AVISTA UTILITIES: (Docket No. UG 165/Advice No. 05-03-G) Reflects changes in the cost of purchased gas and technical adjustments. (Docket No. UM 1215) Requests reauthorization of the PGA deferral mechanism.

**STAFF RECOMMENDATION:**

We recommend the Commission approve Avista Utilities' (Avista or company) request to waive statutory notice (L.S.N.) and allow the company's proposed tariff sheets in Advice No. 05-03-G Supplemental to become effective on October 1, 2005. This filing increases the company's annual revenues by approximately $23.2 million, or 22.5%.

We also recommend the Commission approve the company's request for authorization to use deferred accounting pursuant to its Purchased Gas Adjustment (PGA) balancing account.

**DISCUSSION:**

On August 17, 2005, Avista filed its annual gas cost tracking and technical adjustment application, commonly known as its PGA filing. The PGA allows Avista to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA balancing account. The filing, docketed as UG 165, proposed an $18,935,855 revenue increase, or approximately 18.4%, effective October 1, 2005, to reflect changes in the cost of purchased gas, and amortization of deferred revenue and non-gas cost accounts. In a concurrent filing docketed as UM 1215, Avista requested reauthorization of deferrals under the company's PGA mechanism.

On September 16, 2005, Avista replaced Advice No. 05-03-G in its entirety, and filed replacement Advice No. 05-03-G Supplemental, along with an L.S.N., to reflect (1) the correction of an error in the calculation of gas costs in the company's original filing and (2) an update to the amortization rate for the PGA account to recover the balance over 24 months. The re-filed PGA requests an overall revenue increase of approximately $23.2 million annually, or 22.5%. Avista requested that all proposed tariff sheets become effective October 1, 2005.

## UG 165

In its amended filing, Avista seeks approval for a 22.5% rate increase to its Oregon customers. This rate change consists of an increase in the base cost of the company's system gas supplies, and an increase from adjusting the amortization rates for deferred revenue and gas cost accounts. The total change in annual revenues is summarized below and shown in Attachment A.

| | |
|---|---|
| PGA Base Gas Cost Increase | $ 21,572,240 |
| Removal of Temporary Debit Increment | (5,959,376) |
| Adding New Temporary Debit Increment | 7,891,306 |
| Other Changes[1] | (345,576) |
| Total Proposed Increase | $ 23,158,594 |

With these changes, the monthly bill of a typical residential customer using 53 therms per month will increase by $13.69, or 21.9%, from $62.61 to $76.30. In January, a typical residential customer's consumption of 114 therms would result in a billing increase from $128.91 to $158.37.

A summary of the proposed tariff and revenue changes for Avista's major rate schedules is shown in Attachment A. A summary that compares the impact of this year's proposed PGA rate changes, on both an annual and a January basis, for Avista, Cascade and Northwest Natural residential customers is shown in Attachment B. A graph illustrating each of the three local distribution companies' (LDCs') effective residential rates on a comparable basis is found in Attachment C. The effective residential rate is calculated as follows: the proposed residential rate multiplied by 65 therms plus the monthly customer charge, divided by 65 therms. The graph shows that Avista's residential customers have an effective rate of $1.42223 per therm, while Cascade's and NW Natural's effective rates are $1.16448 and $1.38398, respectively.

[1] Decrease in rates for Transportation Schedule 456 pursuant to Order No. 03-570

The following table shows the rates the Commission has approved for Avista's residential customers on Rate Schedule 410 between 2001 and 2004, and the current proposal.

| Date | Customer Charge | Rate Per Therm | Percentage Change [2] |
|---|---|---|---|
| October 2001 | $4.00 | $0.91367 | |
| April 2002 | $4.00 | $0.76535 | -16.2% |
| October 2002 | $4.00 | $0.71078 | -7.1% |
| October 2003 (PGA) | $4.00 | $0.80672 | 13.5% |
| October 2003 (UG 153) | $5.00 | $0.88787 | 10.1% |
| April 2004 | $5.00 | $0.95764 | 7.9% |
| October 2004 | $5.00 | $1.08689 | 13.5% |
| October 2005 (Proposed) | $5.00 | $1.34531 | 23.8% |

Avista offers customer assistance programs. Specific information on these programs is readily available to customers on their monthly bills, by telephone, in person at the company offices, and on the company's web site.

*National and Regional Natural Gas Markets*

An unprecedented crisis[3] in the natural gas industry has evolved over the last 10 years. The price of natural gas has risen over 300% and, barring a dramatic reduction in demand or huge new supplies, will rise further. Moreover, because North American natural gas production has plateaued,[4] reliability of supply is now also an issue. It is clear that the mistakes of the middle to late 1990s in quantifying remaining North American natural gas reserves and the continuing construction of gas-fired generation to meet the US growing demand for electricity are primary causes of the current crisis. The nonsensical coupling of natural gas and oil prices[5] also contributed to a run-up in natural gas futures price which forced the cash market to follow. Since 1999, over 395

[2] The percentage change reflects only the change in the rate per therm, and does not include the effect of the monthly customer charge on the bill. In 2005, when the rate per therm is combined with the monthly customer charge of $5.00, the average customer's bill is increased about 21.9%, as shown on Attachment B.

[3] American Chemical Council, American Council for an Energy Efficient Economy, Matt Simmons, Joseph Riva, senior geologist Colorado School of Mines, Frank Clemente, Andrew Weissman, National Petroleum Council (which refrains from actually using the word crisis), the International Energy Agency, the US Energy Information Administration, Exxon/Mobile, Royal Dutch Shell, Chevron, Total, and Alan Greenspan.

[4] See Andrew Weissman and the International Energy Agency, in particular.

[5] The two are generally not substitutable except in limited circumstances. Oil and natural gas prices were not historically linked and supply/demand for the two are not generally interconnected. Finally, the physical characteristics of the two are very different, as is their production.

GW of new gas-fired generation has come on line, with more expected to be built. This is to meet electricity demand that is expected to grow at or near 2% a year through at least 2010. By 2015, power generation will likely consume nearly 11 Trillion cubic feet (Tcf) a year more natural gas than it did in 2003. This generation was constructed and continues to be constructed based on erroneous information that North American natural gas supplies would remain plentiful for many decades.[6] This, combined with the low upfront capital cost and generally low emissions of such generation compared to other options, made gas-fired generation seem a clear winner. This has left the US with a continually expanding demand for natural gas that it cannot supply domestically (or even from North America). In short, the US has now entered a chronic (continuing) undersupply situation[7], made worse by the over 232 Tcf of estimated US outer continental shelf and Rockies natural gas that remains off limits for production due to federal restrictions. The push to quickly build more LNG terminals in the US to access world natural gas supply is clear evidence of this US undersupply situation.

*Current Cash (Spot) Price of Natural Gas*

National prices for natural gas have risen consistently over the last year and are expected to continue to increase through the end of 2005. Many forecasters believe the upward trend will subside in the second or third quarter of 2006. The pattern of volatility in natural gas prices appears unabated during the last year, but did not become more intense. Intra-month volatility has been particularly pronounced over the last 2 years. The Henry Hub spot (cash) natural gas price began the period (October 2004) near $6.25/MMBtu, remained relatively constant at that level through February 2005, and began to increase noticeably in March 2005. The Henry Hub price is expected to close the period (September 2005) at about $8.80, a more than 40% increase in price from October 2004.

Northwest natural gas cash prices followed the same general pattern as the Henry Hub, with a basis difference between the Henry Hub and the Northwest averaging about negative $1.25. Northwest prices began the period at $5.05 and ended at just over $7.60, a more than 50% increase in price. Price patterns in the Midwest and Northeast were similar to but not identical to those in the Northwest.

The primary factors that appear to explain these changes in natural gas price are:

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[6] A few claim large supplies remain untapped due to government restrictions. While it is true that large known supplies are off-limits due to government restrictions, these supplies are not large enough to avert the crisis.
[7] Undersupply refers both to depletion of supply and the peaking of production capability in North America.

1. Increased consumer demand (particularly for electric generation), tight supplies, and record crude-oil prices
2. No significant change in LNG imports
3. Increases in Rockies production are primarily unconventional (more expensive)
4. Continuing decline in US production
5. Continuing decline in Canadian production
6. Continuing growth in the US economy

*NYMEX Price*

NYMEX natural gas futures prices also increased noticeably over the period, particularly for winter 2005-2006 gas supplies. The table below depicts the changes in the price for each month over the period on the NYMEX exchange as of August 11. As of September 13, the NYMEX price for most months through September 2006 was up, especially for the winter months which averaged almost $12. The average increase in the NYMEX price over the period since October 2004 is now 55.62 %. A large share of this increase is the result of the shut-ins caused by Hurricane Katrina, but some is systemic and is likely to remain throughout the coming year.

| Month | Price – October 2004 | Price – August 11, 2005 | Change % |
|---|---|---|---|
| October 2005 | $7.00 | $11.00 | +57% |
| November | $7.00 | $10.90 | +56% |
| December | $7.50 | $11.70 | +56% |
| January 2006 | $7.60 | $10.90 | +43% |
| February | $7.60 | $11.90 | +57% |
| March | $7.40 | $10.60 | +43% |
| April | $6.25 | $8.50 | +36% |
| May | $6.20 | $8.20 | +32% |
| June | $6.10 | $8.50 | +39% |
| July | $6.00 | $8.60 | +43% |
| August | $6.10 | $8.65 | +42% |
| September | $6.05 | $8.60 | +42% |
| AVERAGES | $6.73 | $9.84 | +46% |

Over the last year the NYMEX has established a significant premium over current spot (cash) prices, averaging currently over $2 per MMBtu.

As of September 14, 2005, forecasts of natural gas prices for the upcoming winter and beyond have congealed around several values, including the effects of Hurricane Katrina. First, the price at the Henry Hub is expected to be between $11.00 and $11.50 for the final quarter of 2005. This translates to an expected Northwest price of $9.75 to $10.25. Prices at the Henry Hub are forecasted to decline slightly in 2006, averaging just below $8.50, or $7.25 for the Northwest. First, second, and third quarter prices for the Henry Hub in 2006 are expected to average $10.02, $7.53, and $7.20, respectively, according to the EIA. This translates to approximately $8.77, $6.28, and $5.95, respectively, expected for the Northwest. Changes in weather, demand, or supplies could, of course, lead to changes in these price forecasts or to the actual prices experienced.

In addition to the factors listed above under "Current Cash (Spot) Price of Natural Gas," other factors that appear important in explaining the NYMEX price are:

1. The tendency of many NYMEX traders to discount the notion that prices can be controlled through either supply or demand response (e.g., storage, conservation)
2. The tendency of NYMEX traders to focus more on bad news than good, and to place more credence in bad news than good
3. The role definition of "NYMEX" traders as price makers
4. NYMEX traders' generally shallow knowledge of energy engineering and politics, apart from commodity economics[8]
5. Treating natural gas as *only* a commodity[8]

*Gas Supply and Production*

The American Gas Association estimates that 57% (or 1,600 billion cubic feet) of the natural gas flowing to America's homes during the coldest month of the 2005-2006 winter will come from domestic production. This estimated proportion is down by 7% from the 64% from domestic production in 2001-2002. Natural gas from underground storage is expected to supply about 30% of the natural gas used during the 2005-2006 peak winter month, followed by Canadian imports (10.8%), LNG (1.8%) and supplementals, such as propane-air facilities (0.3%). This indicates the increasing importance of storage gas and LNG in meeting US peak winter gas needs.

Many factors can influence production. Hurricanes are certainly one of these factors. The effects of hurricane Katrina on natural gas production in the Gulf of Mexico were substantial. As of August 31 at 4 PM (EST), 8.345 billion cubic feet per day of Gulf natural gas production was shut-in, equivalent to 83.46% of daily Gulf natural gas production (which is 10 Bcf per day). Prices reflected this reduced supply. The NYMEX price reached a high of nearly $11.50/MMBtu at the close of trading on 8/31. The Henry Hub spot price was $12.69/MMBtu on 8/31, up $2.84/MMBtu from the price of Friday, 8/26. At market locations across the Gulf region, price increases ranged up to

[8] An indication of both this ignorance and the treatment of natural gas as only a commodity is a quote in the text, *Trading Natural Gas: A Nontechnical Guide* at page 11, "The supply of natural gas is essentially dependent on only one factor: price." This is nonsense since the major factors determining supply are physical (e.g., geology, physics and chemistry), both in terms of total supply and production.

$4.10/MMBtu with an average of $0.91/MMBtu. The overall average change in price was $0.58/MMBtu.

The price at Northwest trading hubs also increased. The price at AECO went up to $8.75, while Sumas and Rocky Mountain gas increased to near $9.00. As of September 13, 2005, the price effects of Katrina on NYMEX, the Henry Hub, and other trading hubs across the country had dissipated to a large extent. However, as of this date, an increase of about $0.50/dekatherm over the pre-Katrina price was visible at most Northwest hubs, while an $0.80/dekatherm increase was visible at the Henry Hub and about a $1.00/dekatherm increase was visible on NYMEX. It is unlikely that all of this price increase is due directly to Katrina, since prices were rising at all hubs and on NYMEX prior to Katrina. Katrina apparently has had little impact on receipts of shipments at the LNG terminal at Lake Charles, Louisiana. While no major shortages of natural gas have resulted thus far from Katrina, it now seems possible that shortages could be experienced this winter as a result of Katrina, depending on the severity of the winter. The Mineral Management Service reported on September 13, 2005 that 3.720 Bcf/d, or 37.20% of daily gas production offshore remained shut-in as a result of Katrina. There are also concerns that it may be as long as four months before full natural gas production from the Gulf is restored.

## *Avista's Natural Gas Purchasing Strategies*

Portfolio theory has been accepted for the last two decades as the best means to deal with the risks involved in the purchasing of natural gas by LDCs. This theory is based upon a mathematics of diversification. The theory proposes that LDCs focus on selecting portfolios of gas supplies based on their overall risk-reward characteristics instead of merely compiling portfolios of purchases that each individually has attractive risk-reward characteristics. In a nutshell, LDCs in purchasing natural gas should select portfolios not individual supply options. Such a portfolio should display the three characteristics of balance, flexibility, and diversity, and should be based on the particular circumstances in which the purchases are made. And the greater the risks of price change or supply availability, the greater the need to follow the diversity requirements of portfolio theory.

The general elements of an effective LDC gas supply portfolio are laid out in the table below. All portfolios should include each of these options, if available, to the extent possible based on the set of physical, operational, and economic circumstances of the particular LDC.

| No. | Portfolio Components |
|---|---|
| 1 | Base gas contracts |
| 2 | Seasonal contracts |

| | |
|---|---|
| 3 | Pricing in contracts – mix of fixed prices and index prices |
| 4 | Contract take provisions – flexible to allow daily nominations of less than 100% of MDQ without penalty |
| 5 | Storage |
| 6 | Multiple suppliers for all contract types (more than six for each type if possible) |
| 7 | No single supplier with sufficient share to dominate gas supply |
| 8 | All gas contracts staggered in term |
| 9 | Load management, e.g., interruptible sales contracts, real time pricing sales contracts |
| 10 | Buy back contracts |
| 11 | Energy conservation, e.g., weatherization |
| 12 | Financial hedges, e.g., options, swaps, staggered in timing |

The current and likely to continue crisis in natural gas price and supply means that it is even more important that LDCs learn, understand, and apply portfolio practices in their gas purchasing. And because of the ongoing crisis, LDCs will need to work to expand these practices not only to include additional portfolio components but also to include more sophisticated means to evaluate portfolios.

According to Avista's responses to Staff's data requests regarding its filed 2005 PGA,

> Avista has created a diverse portfolio of supply for the coming year. The diversity is both in source/basin and the point in time that the supply was procured. The source of supply is dictated by a combination of economic factors, physical location of load, and contractual capacity limitations. ...Avista's gas procurement plan has historically been one that was a balance of forward purchases over time with spot purchases, and those forward purchases began in April of this year. This year, Avista elected to modify its gas procurement plan and increased the hedged percentage to about 93% of expected load. The modification was the result of: 1) uncertainty related to the future direction of natural gas prices, combined with the tremendous level of price volatility and related global oil prices, and 2) discussions with OPUC staff about differences in hedging strategies between Avista, NW Natural and Cascade. Given the factors above, Avista felt it was prudent to modify its gas procurement plan <u>and to complete the planned purchases by early August</u>. (emphasis in original)
>
> Avista intends to have further discussions with OPUC staff regarding additional modifications to the gas procurement

> plan. Opportunities for those discussions will be through the IRP Technical Advisory Committee meetings this fall as well as the regular ongoing meetings to be scheduled. Avista expects the outcome of those discussions will result in further modifications to the gas procurement plan.

As Avista's answers indicate its gas procurement process is in flux and the Company is anticipating changes to that process over the next year, at least.

Avista's gas supply portfolio is made up of index-based physical contracts, fixed-price physical contracts, and fixed-price financial contracts. The first is a straight forward purchase of volumes at the price for a particular index point during the time period covered by the contract. This price is unknown until the actual index price is published. The second type of contract is for the purchase of gas volumes for a price fixed for the term of the contract. The third contract type is the purchase of a financial hedge against moving gas prices. A common fixed-price financial contract is a fixed-for-floating swap, in which the purchaser agrees to pay the seller a negotiated fixed-price for a pre-determined period and the seller agrees to pay the purchaser the published index price for the same period.

Avista has hedged 93% of expected load for the upcoming year, as already noted above. Currently, Avista has no purchase contracts for longer than one year. The company lists credit, liquidity, and pricing uncertainty as concerns it has regarding longer term purchase contracts and indicates it is currently considering these as it evaluates future changes to its purchasing plan.

Avista's answers to Staff's questions and the filed PGA for 2005 indicate the company has at least a basic understanding of portfolio methods for gas purchasing. However, a fuller and more robust application of these methods is required to effectively address the trends in current natural gas markets toward higher and more volatile prices, and fewer options for LDCs to mitigate these trends. Avista and Staff need to work constructively together over the next few months to ensure this objective is achieved in time for the purchasing season, beginning in April of 2006. Like many LDCs, Avista feels overwhelmed by the current natural gas supply market, largely seeing itself "at the mercy" of this market. While it is true that LDCs have fewer options for controlling gas price than they had in the past and that natural gas is in crisis, it is false that LDCs are wholly at the mercy of the gas market. But taking advantage of these options will require more than just learning and applying portfolio methods and their associated mathematics. It will require that Avista more directly and actively "manage" its gas supply cost on a monthly and sometimes even daily basis, especially during the peak winter period. It also means it will not be feasible for Avista to financially hedge almost all volumes purchased unless the hedging strategy is in line with the general requirements of portfolio methods and the specific portfolio practices designed for the Avista system and circumstances.

Specifically, Staff recommends Avista incorporate the following suggestions for future natural gas purchases:

1. If possible, Avista should look to add more and more flexible pricing options to its supply contracts (e.g., index changes, flexible MDQ, flexible nominations, weather derivatives).
2. Expand bidding (e.g., combination supply/transport, bid for hedges, direct comparison of bidding options).
3. Look into purchase partnerships with other LDCs or industrial customers.
4. Avista should analyze the following possible additional gas supply portfolio components:
    a. More volumes purchased through contracts of 5 years or longer (a workable option for an LDC the size of Avista)
    b. Direct LNG contracting
    c. Direct contracting for unconventional gas supplies
5. Improve coordination of energy efficiency programs, demand-response, buy-back contracts, and gas purchasing, to fine tune how the options might work together and get the maximum benefit in terms of customer cost.

Staff also suggests that Avista more rigorously apply portfolio methods through mathematical testing (statistical) of varied portfolios.

*Avista's Natural Gas Costs*

For the time during which Avista purchased gas for the period October 2005 through September 2006, the average cash (spot) price in the Northwest was approximately $6.00/MMBtu, with prices noticeably higher during the last two months of the period (July and August 2005). The NYMEX price closed the period (September 2006) at over $9.00 ($7.75)/MMBtu,[9] with prices between $11 ($9.75) and $12 ($10.75) per MMBtu for the winter months of 2005-2006. However, the NYMEX price for September 2006 ranged from $6.75 ($5.50) to near $7.25 ($6.00) during April and May of 2005, began to rise noticeably in early June, ending finally just over $9.00 ($7.75) at the end of August. After a spike during March and early April over $8.50 ($7.25), the NYMEX price for the winter months declined below $8.00 ($6.75) in April before beginning a climb in May which, thus far, has produced a high near $12.00 ($10.75).

[9] Prices in parentheses are estimated Northwest prices based on an average basis difference from national price of ($1.25).

The limitations of Avista's gas purchasing process already identified should be addressed as soon as possible and Avista should work to incorporate more and more diversified options for controlling the price it pays for natural gas. For the current PGA, Avista proposes to pass through to its sales customers an average delivered natural gas cost of $0.77586/therm ($7.76/dekatherm (MMBtu)), based on normalized purchase volumes. Avista then adds commodity-related delivery costs and line losses to this value and calculates a revenue sensitive rate per therm of $0.79768 ($7.98/dekatherm (MMBtu)). This pass through proposal stands out when compared with the sales WACOGs proposed by the other LDCs, Cascade and NW Natural.

Based on this history of prices in the Northwest and the general practice of purchasing over the period between April/May and September during the year, the expected price for hedged volumes would be in the range of $7.00 to $7.15/dekatherm. The hedged cost of gas proposed by Cascade falls slightly below this range while the hedged cost of gas proposed by NW Natural falls within the range. However, Avista's proposed cost of hedged natural gas volumes is about 9% higher than the top of this range.

As noted in Avista's responses to Staff's data requests quoted above, the company changed its purchasing plan regarding the amount of gas purchase volumes it intended to hedge financially, but it did not make the change until late July. The final decision by Avista was to hedge 93% of expected load, a more than doubling of the percentage of expected load to be hedged according to Avista's plan put in place at the beginning of the purchasing season in April 2005.

Since this decision was made by Avista in late July, the company was forced to hedge the entire amount of its thus far "unhedged load," more than one-half of its expected load, in July and August, less than 30 days before the 2005 PGA was to be filed. This violates one of the basic tenets of portfolio theory, which emphasizes diversity in all aspects of gas purchasing, including timing.

Because of this decision, for the then unhedged portion of expected load, Avista was unable to diversify its hedging purchases over the entire purchase period, but instead was forced to compress the hedge purchases into a period of less than 30 days. That the hedge prices were higher is a function of the upward direction of NYMEX futures price over the entire purchase period, meaning that the highest prices for the period were at its end. However, Avista's action violates portfolio theory decision making regardless of the particular pattern of the NYMEX futures price. Avista failed to diversify over time its hedge purchases.

Based on its responses to Staff data requests, Avista apparently understands and attempts to implement diversity, both in terms of physical sources of natural gas and the timing of purchases.[10] But Avista directly violated this basic portfolio principle in its purchasing of hedges. This is one of the fundamental differences between hedging (to control volatility and help mitigate up turns in gas price) and speculation. Speculators try to guess which direction price in the market will go and based on that guess seek to make a profit by buying and selling NYMEX futures contracts. This is not appropriate behavior for an LDC. The discipline of portfolio methods is important to clearly demarcate hedging and speculation.

The decision in July by Avista to greatly increase the volumes of gas purchases it hedged and thereby force these new hedges to be completed in a period of less than 30 days raises the issue of whether this decision and its results are prudent and whether all or some portion of the gas cost increase requested by Avista should be disallowed. Several factors support the conclusion that the decision and its results are imprudent:

1. As indicated above, the decision forced Avista to violate one of the basic tenets of portfolio purchasing – the need for diversity in all aspects of purchasing to mitigate risks, including the timing of hedge purchases. That is, portfolio methods direct that hedges, like gas volumes themselves, be purchased in segments over the entire purchasing season (April/May to September) rather than during any particular part of the season.
2. The decision to hedge significantly more volumes late in the season is not a part of any long-term hedging/purchasing strategy prepared, documented with research and analysis, and tested through experience by Avista. Purchasing/hedging natural gas volumes should not respond to short-term price and supply signals, but rather must be part of a well designed, researched, and tested long-term strategy that takes into account the multiple long- and short-term factors that affect natural gas price and availability.
3. Avista has provided no specific market intelligence or analysis of that intelligence supporting the decision as reasonable. In fact, the July 21, 2005 memo written by the Gas Supply Manager to Avista's Risk Management Committee (RMC) and Strategic Oversight Group (SOG) appears to recommend the change in hedging strategy primarily because Avista is now subject to a "90%/10% sharing of the difference between actual and estimated monthly gas costs…" <u>Actual</u> market intelligence about an impending significant up-turn in natural gas price and/or gas price volatility and analysis of that intelligence is not mentioned in that memo.

At the same time Avista has offered several factors that suggest the decision was not imprudent:

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[10] "Avista has created a diverse portfolio of supply for the coming year. The diversity is both in source/basin and the point in time that the supply was procured."

1. The Commission has not adopted guidelines for purchasing/hedging strategies. Staff recently completed a study on natural gas procurement, and plans to follow up that study with an investigation on the effect of current sharing mechanisms on the LDCs' purchasing and hedging strategies. We plan to work closely with the LDCs and interested parties over the next two months on an informal basis prior to opening a formal investigation.
2. Avista has assured Staff that it used typical market intelligence (articles from industry publications) in its purchasing strategy but has provided no documentation of such information, nor any documentation of how it used that market intelligence to support its decision to change its hedging strategy for Oregon ratepayers.
3. It is likely that the total cost of Avista's gas supply, including spot (cash) purchases, would have been higher had the company continued its original strategy to hedge less than the 93% of expected load. Staff can speculate that spot purchases for any significant share of Avista's gas supply over the next year could have potentially cost the company, and its customers, millions of dollars more.

Based on NYMEX futures during the April/May to September 2005 period, Staff estimated a reasonable sales WACOG for Avista to be $0.70603/therm ($7.06/dekatherm (MMBtu)), about 91% of the WACOG level proposed by the company in its filing, and within the range of hedge prices for this period that could reasonably be expected. A full disallowance of the excess costs would reduce Avista's proposed rate increase related to gas cost by $6,462,690, down to $15,109,550.

Another option the Commission might consider is a disallowance of a portion of the gas cost increase requested by Avista in its filing. Such a disallowance might serve to underscore the importance of Avista following the generally accepted portfolio practices for gas purchasing, including the use of appropriate mathematical tools and completion of necessary research and analysis. This would certainly encourage Avista to develop a balanced, flexible, and diverse portfolio strategy that could accommodate and provide the analytical rigor to properly address changes in market conditions, such as those Avista says prompted it to change its hedging strategy in July.

If any disallowance is ordered, Staff recommends the difference between the WACOG proposed by Avista and the reduced WACOG not be recoverable by Avista through any type of deferral account or mechanism.

Notwithstanding all the aforementioned discussion, Staff is not recommending a disallowance at this time because Staff cannot draw a nexus between harm to the ratepayer and the company's decision to change its hedging strategy. However, Staff is disturbed about Avista's lack of control in its gas procurement process.

1. The process is not well organized; it demonstrates lax internal monitoring and controls. There are no minutes of any meetings of the internal oversight groups (who are charged with reviewing and approving such changes) on the decision to change the hedging strategy at Avista. Even though Avista's internal documents indicate meeting minutes will be created, there is also no written approval for this change from these oversight groups. And since there are no minutes of meetings, or written approval, there is no documentation of the reasons such an approval was granted.
2. The process also displays inadequate research and analysis of market intelligence. Avista has no quantitative or even detailed qualitative analysis to support the decision in July to change its hedging strategy. Additionally, it is not apparent that any such analysis was presented to the internal oversight groups before the decision was made.
3. According to Avista, the company made the decision to change its hedging strategy to "protect against the possibility of a significant rise in prices this coming winter." This is a valid reason for changing a purchasing strategy only if it is based upon reasonable research and analysis of reliable market intelligence covering both the pros and cons of available actions for addressing the problem effectively. As already noted, Avista has provided no evidence that it did any of this research and analysis. But equally troubling is the fact that Avista did not implement this new strategy, or any change in its existing strategy in Washington or Idaho. The decision not to implement the new strategy was apparently due to the fact that neither the Washington nor the Idaho regulatory authorities require gas cost sharing mechanisms. Therefore, Avista does not risk any shareholder responsibility for gas cost sharing in the other two states. Staff believes this difference in strategy for the other states belies the company's claim that the increased hedging (for Oregon ratepayers only) was a response to market conditions. It is wholly inappropriate and inconsistent with portfolio purchasing to make changes to a purchasing strategy based on such reasoning.
4. Finally, and most importantly, the company lacks a formal long-term purchasing and risk management strategy that is consistent with accepted portfolio purchasing practices, provides for sufficient research/analysis to support particular decisions made regarding purchasing, and ensures that full documentation of decisions and their basis is prepared at the time the decision is made. Avista has a "Natural Gas Supply, Procurement, and Hedging Policy." But this document is little more than some general guidelines and a division of responsibilities for "everyday" actions.

The lack of rigor in Avista's gas purchasing decision-making process and oversight indicates a lack of management attention and control. Staff will monitor Avista's purchasing process and address the status of that process in its review of Avista's 2006 PGA filing.

Staff recommends the Commission allow the increase in gas cost as requested by Avista to go into effect. However, Staff also recommends that Avista work with and provide regular reports to Staff in the following areas:

1. Development of a long-range purchasing and risk-management strategy that is consistent with accepted portfolio purchasing practices.
2. Inclusion in this strategy of comprehensive consideration by Avista of long-term contracting for supply and other contracting practices designed to control the price paid for natural gas.
3. Inclusion in the strategy of means to assess, quantitatively if possible, the impact, if any, of Avista's credit difficulties on the price of natural gas paid by Avista.
4. Development of clear procedures and guidelines, including oversight by company officers, of the actual implementation of this long-term strategy, including the timing of hedging decisions and purchases.
5. Full participation in the informal workshops and later, formal investigation into the PGA mechanism, along with the other LDCs, to provide the Commission Staff and Commission with meaningful input into if and how the company's gas purchasing strategies are affected by the mechanism, and how changes to the mechanism may ultimately affect the cost of gas passed through to its customers.

Noting once again that future natural gas prices are very likely to be even higher and perhaps more volatile, the changes proposed for Avista's purchasing process should help control its future cost of gas, thus limiting future increases and rate shock.

**Technical Adjustments – Deferred Accounts**

Staff has reviewed the deferred accounts and verified the accuracy of the amortization rates, the accuracy of the costs posted to the accounts, the interest rates applied to the accounts and the calculation of lost margins. Over the past twelve months, Staff has worked closely with Avista to improve the models used by the company to make these calculations as well as the reporting format and documentation needed by Staff to review the accuracy of these accounts.

In the August 17, 2005 original filing of this PGA, Avista proposed that there be no change to the present amortization rate used to recover costs in the PGA deferral account. In its 2004 PGA filing, Avista requested a 24-month recovery time be allowed in the PGA deferral account which was applied to the balance of the deferral account from October 1, 2004 to September 30, 2005.

In its review, Staff discovered that no change to the amortization rate results in an inadequate rate to recover the full balance of the deferral account within the 24-month period agreed to by Staff and proposed by Avista. Staff requested the company recalculate the rate. The recalculated rate resulted in an adjustment to the rate equivalent to approximately a two cent per therm increase in the amortization rate.

Northwest Industrial Gas Users (NWIGU) expressed a concern about the dramatic rate increase proposed in the company's filing and requested that Staff consider extending the amortization of the PGA deferral account balance from 24 months to 30 months. Staff reviewed several potential options available to address rate shock to consumers and still recommends that the 24-month amortization period is the most appropriate to avoid further accumulation of interest, further deferral of future gas costs and to address concerns about deferred charges allowed in the company's most recent general rate case (UG 153) that still have not been amortized to residential and commercial customers.

**Earnings Review and 3% Test**

Until 1999, as a matter of policy, the Commission conducted earnings reviews for both prospective purchased gas costs changes and PGA-related deferrals. The Commission then adopted OAR 860-022-0070, which requires an annual spring earnings review in lieu of an earnings review related to prospective purchased gas cost changes. In addition, Section (8) of that same rule states that an earnings review is not applicable to amortization of deferred gas costs if the LDC assumes at least 33% of the responsibility for commodity cost differences in the risk sharing mechanism. In 1999, the Commission allowed Avista to implement an experimental natural gas benchmark mechanism (GBM). At the March 5, 2002 Public Meeting, the Commission approved Avista Utilities request to renew its GBM for a three-year period ending March 31, 2005.

On August 2, 2005, Avista filed a proposed new Schedule 462, Purchased Gas Cost Adjustment Provision - Oregon, in Advice No. 05-02-G. Schedule 462 is a temporary PGA mechanism, the terms of which reflect numerous discussions between Staff and the company. As set forth in the tariff, beginning October 1, 2005, the company will defer 90 percent of the difference between its monthly actual and estimated commodity cost of gas. As this sharing level is less than the 67/33 percentage sharing prescribed under OAR 860-022-0070(8), the company is now subject to a fall earnings review, as well as the mandated spring earnings review, beginning in 2006. The proposed tariff also includes an agreed-upon reduction in the earnings threshold from 300 to 200 basis points above the company's authorized return on equity, as adjusted.[11] For the 2005 spring earnings review, Avista's earnings threshold was 13.33 percent. For purposes of

[11] The earnings threshold is adjusted annually to reflect 20 percent of any change in the risk-free rate (see Order No. 04-203).

illustration, assume no change in Avista's 2005 earnings threshold. If the company is earning more than 12.33% on equity at the time of the 2006 spring earnings review, it will share the amount it is "overearning" with its customers. The purpose of the fall earnings review is to determine whether or not Avista should absorb any of its deferrals. At the time of the fall earnings review in 2006, Avista has agreed they would be at risk for not amortizing the amount of deferrals accumulated from October 1, 2005, through September 30, 2006, or returning to customers 80 percent of the overearnings above the threshold (again, 12.33 percent in this example), whichever is less.[12] On August 16, 2005, the Commission adopted 05-02-G as proposed on its consent agenda.

ORS 757.259(6) and (7) states that the overall annual average rate impact of the amortizations authorized under the statute may not exceed three percent of the utility's natural gas gross revenues for the preceding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. To mitigate the overall impact of this rate increase, Avista proposes to amortize $12.8 million over a two-year period. The amortization rate recovery for deferrals not related to the recovery of purchased gas costs fall below the three percent threshold pursuant to the utility's natural gas gross revenues for the preceding year. Staff finds that the rate increase is just and reasonable and recommends the Commission adopt the increase pursuant to ORS 757.259(7).

**UM 1215**

In this filing, Avista requests reauthorization of deferrals pursuant to its automatic adjustment clause, the PGA mechanism. The PGA allows the company to adjust tariffs annually for known and measurable changes in purchased base gas costs and for changes in amortization rates relating to the PGA balancing account.

The information contained in the application is consistent with the requirements of ORS 757.259, 757.210 and OAR 860-027-0300. The application states that continued deferral of these cost and revenue differences minimizes the frequency of rate changes and appropriately matches costs borne and benefits received by ratepayers, consistent with ORS 757.259(2)(e). The reasons cited for reauthorization are still valid. Staff recommends the Commission approve the request for reauthorizing the PGA, effective October 1, 2005.

[12] See Order No. 98-543, Appendix A, Page 4.

**PROPOSED COMMISSION MOTION:**

Avista Utilities' request to approve the company's L.S.N. and allow the company's proposed tariff sheets in Advice No. 05-03-G Supplemental to become effective on October 1, 2005, and the company's request for reauthorization to use deferred accounting pursuant to its PGA balancing account be approved.

Attachments

Avista 2005 PGA and UM 1215

Avista Utilities
Oregon Gas Operations
Summary of Present and Proposed Rates
2005 PGA Tracking Application



| Line No. | Description | Rate Sch | Adjusted Sales (Therms) | Revenues at Present Rates | PGA Gas Costs | | | Temporary Increments | | Other Changes (Note 1) | Total Change | | Revenues at Proposed Rates |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Demand Portion | Commodity Portion | Total Change | Remove Old | Add New | | In Rates | In Revenue | |
| | (A) | (B) | (C) | (D) | (E) | (F) | (G) | (H) | (I) | (J) | (K) | (L) | (M) |
| 1 | Residential | 410 | 51,812,884 | $61,082,625 | $271,500 | $12,019,035 | $12,290,535 | ($3,396,335) | $4,495,286 | | $0.25842 | $13,389,486 | $74,472,111 |
| 2 | General | 420 | 28,504,205 | $29,361,879 | $149,362 | $6,612,120 | $6,761,482 | ($1,868,451) | $2,473,025 | | $0.25842 | $7,366,057 | $36,727,936 |
| 3 | Large General | 424 | 4,039,540 | $3,893,693 | $21,167 | $937,052 | $958,219 | ($264,792) | $350,470 | | $0.25842 | $1,043,898 | $4,937,591 |
| 4 | Emergency Instit. | 430 | | | | | | | | | $0.25842 | | |
| 5 | Interruptible | 440 | 6,534,247 | $5,036,794 | | $1,515,749 | $1,515,749 | ($417,016) | $555,607 | ($67,564) | $0.24284 | $1,586,776 | $6,623,570 |
| 6 | Seasonal (2) | 444 | 194,996 | $184,556 | $1,022 | $45,232 | $46,255 | ($12,782) | $16,918 | | $0.25841 | $50,389 | $234,945 |
| 7 | Special Contract | 447 | 13,942,231 | $558,982 | | | | | | | | | |
| 8 | Firm Transportation | 455 | | | | | | | | | | | $558,982 |
| 9 | Int. Transportation | 456 | 36,217,112 | $2,780,124 | | | | | | ($278,012) | ($0.00768) | ($278,012) | $2,502,112 |
| 10 | TOTAL | | 141,245,215 | $102,898,653 | $443,051 | $21,129,188 | $21,572,240 | ($5,959,376) | $7,891,306 | ($345,576) | | $23,158,594 | $126,057,247 |

Note 1 Per Commission Approved Stipulation in Docket UG-153, Order No. 03-570

Attachment A
ORDER NO. 05-1053

**Attachment B**

**Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service**
(October 2005 PGAs)

| Class of Service | Rate Schedule | RATE IMPACTS | | | | BILL IMPACTS | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Current Rate per Therm | Proposed Rate per Therm | Change Rate per Therm | %-Change Rate per Therm | Average January Therms | Customer Charge | Current January Bill | Proposed January Bill | Change January Bill | %-Change January Bill | Annual Therms/ Month | Customer Charge | Current Monthly Bill | Proposed Monthly Bill | Change Monthly Bill | %-Change Monthly Bill |
| **Residential** | | | | | | | | | | | | | | | | | |
| Avista | 410 | $1.08689 | $1.34531 | 0.25842 | 23.8% | 114 | $5.00 | $128.91 | $158.37 | $29.46 | 22.9% | 53 | $5.00 | $62.61 | $76.30 | $13.69 | 21.9% |
| Cascade | 101 | $0.97948 | $1.11833 | 0.13885 | 14.2% | 131 | $3.00 | $131.31 | $149.50 | $18.19 | 13.9% | 63 | $3.00 | $64.71 | $73.45 | $8.74 | 13.5% |
| NW Natural | 2 | $1.10784 | $1.29167 | 0.18383 | 16.6% | 122 | $6.00 | $141.16 | $163.58 | $22.42 | 15.9% | 59 | $6.00 | $71.36 | $82.21 | $10.85 | 15.2% |
| **Commercial** | | | | | | | | | | | | | | | | | |
| Avista | 420 | $1.00313 | $1.26155 | 0.25842 | 25.8% | | | | | | | | | | | | |
| Cascade | 104 | $0.87928 | $1.01813 | 0.13885 | 15.8% | | | | | | | | | | | | |
| NW Natural | 3 | $1.02239 | $1.19803 | 0.17564 | 17.2% | | | | | | | | | | | | |
| **Industrial** | | | | | | | | | | | | | | | | | |
| Avista | 424 | $0.94671 | $1.20513 | 0.25842 | 27.3% | | | | | | | | | | | | |
| Cascade | 105 | $0.83947 | $0.97832 | 0.13885 | 16.5% | | | | | | | | | | | | |
| NW Natural | 31 | $0.99346 | $1.15524 | 0.16178 | 16.3% | | | | | | | | | | | | |
| **Interruptible** | | | | | | | | | | | | | | | | | |
| Avista | 440 | $0.77803 | $1.01367 | 0.23564 | 30.3% | | | | | | | | | | | | |
| Cascade | 170 | $0.77643 | $0.91482 | 0.13839 | 17.8% | | | | | | | | | | | | |
| NW Natural | 32 | $0.77579 | $0.93900 | 0.16321 | 21.0% | | | | | | | | | | | | |

**Attachment C**