ORDER NO. 06-610

ENTERED 10/30/06

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 176/UM 1279

In the Matters of AVISTA CORP., dba AVISTA UTILITIES Purchased gas cost adjustment to change rates within Avista Utilities' natural gas service schedules to reflect the projected cost of gas pursuant to tariff Schedule 461, Purchase Gas Cost Adjustment Provision. **(UG 176)** Application for Reauthorization of Certain Deferral Costs. **(UM 1279)**	))))))))))))	ORDER

DISPOSITION: APPLICATIONS APPROVED;
INVESTIGATION OPENED

On August 31, 2006, the Public Utility Commission of Oregon (Commission) received two applications from Avista Corp., dba Avista Utilities. A description of the filings and their procedural history is contained in the Staff Report, attached as Appendix A and incorporated by reference.

Based on a review of the applications and the Commission's records, the Commission finds that the applications satisfy applicable statutes and administrative rules. At its Public Meeting on October 25, 2006, the Commission adopted Staff's recommendation to approve the applications and allow the associated tariff sheets in Advice No. 06-06-G Supplemental to go into effect subject to refund. The Commission also approved Staff's recommendation that an investigation be opened under ORS 757.210 and 757.215 to examine Avista's gas purchasing strategy, particularly the company's level of financial hedging for Oregon volumes within the context of company-specific prudent purchasing practices.

ORDER

IT IS ORDERED that:

1. Amortization of deferred accounts, as requested in docket UG 176, is approved.

2. The associated tariff sheets in Advice No. 06-06-G Supplemental are allowed to go into effect with service on or after November 1, 2006, subject to refund, with less than statutory notice.

3. Reauthorization to use deferred accounting pursuant to Schedule 461, and for the reduction in margin for interruptible and transportation customers as set forth in Order No. 03-570, as requested in UM 1279, is approved.

4. An investigation pursuant to ORS 757.210 and ORS 757.215 be opened to examine Avista's gas purchasing strategy.

Made, entered, and effective OCT 3 0 2006.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

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 by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

ITEM NO. 5 & 6

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 25, 2006

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** November 1, 2006

DATE: October 18, 2006

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 176/Advice No. 06-06-G) Reflects changes in the cost of purchased gas and technical adjustments. (Docket No. UM 1279) 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. 06-06-G Supplemental to become effective on November 1, 2006, subject to refund. This filing increases the company's annual revenues by approximately $8.7 million, or 6.9%.

We recommend the Commission approve the company's request for authorization to use deferred accounting pursuant to its tariff Schedule 461, Purchased Gas Cost Adjustment Provision.

We also recommend the Commission open an investigation to address whether Avista's natural gas prices are higher than appropriate, given the company's characteristics and gas purchasing options.

DISCUSSION:

On August 31, 2006, 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 account and other deferred accounts. The filing, docketed as UG 176, proposed an $11,045,388 revenue increase, or approximately 8.8%, effective November 1, 2006. This filing reflects the changes in the cost of purchased gas and amortization of deferred revenue, gas cost and non-gas cost accounts through the temporary increment adjustment. In a concurrent filing docketed as UM 1279, Avista requested reauthorization of deferrals under the company's PGA mechanism.

On October 6, 2006, the company replaced Advice No. 06-06-G in its entirety and filed replacement Advice No. 06-06-G Supplemental, along with an L.S.N., to lower its projected spot natural gas forecast. The re-filed PGA requests an overall revenue increase of approximately $8.7 million annually, or 6.9%. Consistent with Commission Order No. 06-568, entered October 2, 2006, the company proposes an effective date of November 1, 2006—a permanent one-month shift, from October 1 to November 1, in the effective dates of the annual PGA filing and deferral request.

UG 176

In its amended filing, Avista seeks approval for a 6.9% 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 a decrease 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	$ 10,640,993
Removal of Temporary Debit Increment	(7,908,193)
Adding New Temporary Debit Increment	5,967,721
Total Proposed Increase	$ 8,700,521

With these changes, the monthly bill of a typical residential customer using 52 therms per month will increase by $5.30, or 7.1%, from $75.06 to $80.36. In January, a typical residential customer's consumption of 98 therms would result in a billing increase from $137.03 to $147.03.

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 60 therms plus the monthly customer charge, divided by 60 therms. The graph shows that Avista's residential customers have an effective rate of $1.53264 per therm, while Cascade's and NW Natural's effective rates are $1.26082 and $1.44052, respectively.

The following table shows the rates the Commission has approved for Avista's residential customers on Rate Schedule 410 between 2002 and 2005, and the current proposal.

Date	Customer Charge	Rate Per Therm	Percentage Change [1]
October 2002	$4.00	$0.71078	
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	$5.00	$1.34729	24.0%
November 2006[2] (Proposed)	$5.00	$1.44931	7.6%

Avista offers customer assistance programs. Avista also offers energy efficiency programs through the utility and through Energy Trust of Oregon. 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

2005 was a very eventful year for natural gas in the US. Prices rose to unprecedented levels and price volatility was rampant. Soon after the turn of the year, however, many factors combined to tame this very dangerous market and thus reduce natural gas prices:

- The winter of 2005-2006 was generally mild; no great demand was placed on existing natural gas supply;
- The summer of 2006 was, apart from a few occasions on both coasts and in the Midwest, a mild summer in terms of the use of natural gas to generate electricity to meet cooling demand;
- No major supply interruptions have occurred to date; the hurricane season has been mild and uneventful;
- The prices of natural gas and oil have generally de-linked—rising oil prices are no longer carrying natural gas price along;
- Gas storage injections and inventory levels are at historic highs;
- The futures markets, including speculators and hedge funds traders, have generally not been able to promote any sustained increase in natural gas

[1] 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 2006, when the rate per therm is combined with the monthly customer charge of $5.00, the average customer's bill is increased about 7.1%, as shown on Attachment B.
[2] The annual PGA effective date is permanently changed from October 1 to November 1 effective this year.

prices; futures prices across the country have consistently and generally declined, with particularly sharp declines in the West (e.g., Rockies);
- Demand destruction resulting from the hurricanes and higher prices of 2005 exceeded the supply lost because of the 2005 hurricanes;
- Domestic supply has remained steady, with no substantial decline—there has been a 300% increase in the number of wells drilling for domestic natural gas, helping domestic supply remain steady or even increase slightly;
- LNG imports, while not growing, remain poised to increase over the next several years; and
- The development of unconventional natural gas sources (e.g., coalbed methane, tight sands, deep-water) has expanded with significant events on both the technical and financial fronts.

Of course other potential factors may lead to increases in the price of natural gas. LNG imports into the US, while expanding, are not increasing at nearly the rate expected a few years ago. Plus, many other countries in the world are bidding for LNG supplies to help "fuel" their economic growth. Biggest among these are Japan, Korea, and several countries in Europe. Second, imports of natural gas from Russia to Europe, China, etc., are not growing as quickly as expected and it appears that Russia (the single largest holder of natural gas reserves in the world) is increasingly using natural gas and oil as foreign policy tools to seek control of the actions of other nations. Third, weather can play a large part in increasing natural gas price. For example, an up tick in the severity or length of the US hurricane season or an exceptionally cold winter in either the US or Europe could lead to significant increases in prices. Fourth, any large increase in either industrial production or the use of natural gas for electric generation could potentially lead to increases in the price of the resource. Fifth, any failure in the expected level or growth in the level of domestic natural gas production, either conventional or unconventional, could connect to an increase in price. Finally, the futures markets for natural gas, particularly the hedge funds involved in those markets, dominate both that market and the physical natural gas market in terms of money invested. With those futures markets not currently functioning in accordance with even the most expansive understanding of "market theory," the impacts of these markets on future natural gas prices cannot be understood and thus are impossible to forecast. Both market theory and government enforcement of market fundamentals will need to evolve to address this issue appropriately.

The US Department of Energy's Energy Information Agency (EIA) forecast of natural gas price at the Henry Hub has been declining since January. The next 12-months EIA forecast began the year at $9.81/MMBtu and steadily declined from that point. In its August 8, 2006 forecast, the EIA projected an average price for the next 12-months at the

Henry Hub of $8.06/MMBtu and projected an average Henry Hub price for the winter season at the Henry Hub of $9.05/MMBtu. These forecasts translate to natural gas prices, for the hubs from which Oregon LDCs purchase, of less than $7.00/MMBtu for the PGA year and less than $8.00/MMBtu for the winter season. Of course, all Oregon LDCs lock-in the price of a portion of their natural gas supply portfolio well in advance of the 2006-2007 winter season, including multi-year fixed price financial contracts, and place natural gas into storage during the off-peak season for withdrawal during the winter season. This means the overall pricing for their portfolios cannot, and properly should not, reflect only current natural gas prices.

Currently it seems the factors holding natural gas prices somewhat in check will control the futures and physical markets at least through the end of 2007. This should mean only slight increases over the next year from present prices and may even lead to some small price decreases in some parts of the US, including the Northwest.

The Appendix at the end of this document provides significant detail on the cash (spot) and futures prices for natural gas both nationally and regionally, as well as some discussion of futures pricing and gas supply, production and demand.

Natural Gas Purchasing Strategies

As Staff emphasized strongly in its PGA public meeting memos last year, and continues to emphasize strongly for its 2006 PGA memos,

> "[p]ortfolio 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. . . .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. . . .All portfolios should include each of the options in the table below, 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

No.	Portfolio Components
4	Contract take provisions – flexible to allow daily nominations of less than 100% of MDDV[3] 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 decline in natural gas prices does not lessen but rather increases the importance of adhering strictly to portfolio purchasing. With prices declining there may be a temptation to deviate from such purchasing in favor of purchasing as much as possible at current low prices. This is an error. Deviating from portfolio purchasing places the LDC into the position of speculating, guessing the direction of prices for natural gas in the future. Since it is impossible to consistently forecast accurately future natural prices, portfolio purchasing is the most effective means currently available to mitigate the impacts on both customers and the LDC of price movement of whatever size and whatever direction. For just as surely as natural gas prices can decline sharply, as they have in the last 6 months, they can also and just as quickly increase sharply. It is important that LDCs understand and apply portfolio practices in their gas purchasing. LDCs need to commit to expand these practices not only to include additional portfolio components but also to include more sophisticated means to evaluate portfolios.

Staff emphasizes the following points about portfolio purchasing that should be applied by all three LDCs. These points have been reviewed in meetings with the LDCs throughout the past year, and will be further discussed in a formal investigation (a request for a Commission investigation into the PGA Mechanism will be made before the end of the year) to be conducted in 2007.

1. In specific practice, portfolio purchasing means the LDC <u>must</u> purchase a combination of resources, including demand-side options, to meet the needs of its customers that are balanced, diverse, and flexible. Thus it is not just the size of each resource making up the portfolio that must meet these objectives but also such elements of the portfolio as timing, duration of supply contract, location of supply, contracting form/type, pricing, etc.

[3] MDDV is Maximum Daily Delivery Volume and represents the company's maximum daily responsibility to a customer.

2. While the current natural gas market arrangements do limit the options of LDCs in controlling the level and volatility of the price paid for natural gas, portfolio purchasing provides an array of tools to retain at least some LDC control over these pricing concerns.

3. Overemphasizing any particular resource option(s) in a portfolio is contrary to the proper application of portfolio purchasing, no matter the precise form of that overemphasis or the resource(s) to which it is applied. In 2005 all the Oregon LDCs entered into financial hedging arrangements for too large a share of their natural gas supply. Staff's public meeting memo last year and ensuing discussion with the three LDCs all indicated that a balanced approach was needed. For the 2006 PGA, Avista continues to financially hedge roughly 90% of its volumes. As prices declined, Avista was less able to take advantage of these lower prices on behalf of its Oregon customers, but did re-file its PGA after it was able to re-price (at a lower cost) its unhedged volumes (more detail on this filing later in this memo) and incorporate those lower prices into the PGA filing.

4. Purchasing natural gas via the portfolio approach requires more attention and effort by the LDC to gather, review, interpret, and apply market intelligence in constructing the portfolio; in monitoring the actual functioning of the portfolio constructed; and in modifying the portfolio as market or operational changes require. This is hard work, especially when compared to purchasing natural gas from daily, weekly, or monthly cash markets.

5. There is no "one size fits all" in portfolio construction. Each portfolio must be designed, constructed, applied, and reviewed based on existing and expected market conditions, and the demand, supply, operational, and general economic circumstances of the LDC for whom the portfolio is being constructed.

6. Each and every portfolio decision and action must be as fully documented as possible. That is, the details behind every decision and action in making a portfolio choice must be available for review and analysis by the LDC and Staff without any extraordinary effort on the part of either the LDC or Staff.

Avista's Natural Gas Purchasing Strategies

As described below, Staff has several serious concerns regarding Avista's gas purchasing strategy, particularly the company's decision to financially hedge over 90% of its volumes prior to the PGA year:

- Avista has not justified its level of financial hedging for Oregon volumes within the context of company-specific prudent purchasing practices,
- The company's use of Oregon's gas cost recovery mechanism as a rationale for its hedging level is unreasonable, and
- Avista's hedging level in Oregon at the time of the PGA filing was far higher than in its Washington and Idaho service territories, even after accounting for storage.

In its 2006 PGA filing Avista proposes the following natural gas supply portfolio:

Firm natural gas contracts for the entire year, winter season, or some other portion of the PGA year financially hedged to fix the price (as of the time of the PGA filing)	91%
Storage	1%
Short-term and peaking natural gas purchased at index price (unhedged)	8%

This portfolio is virtually the same as that proposed and approved for Avista as part of its 2005 PGA filing. However, Staff was critical of that portfolio and made clear in its 2005 PGA public meeting memo for Avista that the company should reduce its reliance on financial hedging and purchase a larger share of its gas supply at current index prices. Staff stated then that it was "false that LDCs are wholly at the mercy of the gas market," and that "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" and that "[i]t 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 . . . ." *Avista Utilities 2005 PGA Filing at page 9.* Avista has not followed this recommendation.

At the September 22, 2005, public meeting, Staff explained that Avista generally understands and tries to apply portfolio methods, but still failed to follow such purchasing practices. Staff explained at the time, that it was unable to "draw a nexus between harm to the ratepayer and the company's decision to change its hedging strategy" because had the company followed the method appropriately to reduce its risk from overuse of financial hedging, prices would actually have been higher (because prices were then increasing considerably due to the fallout from Hurricanes Katrina and Rita). *See 2005 Staff Report, page 13.* Regardless of the particular prices for the 2005 PGA, however, the main point here is that Avista disregarded accepted portfolio purchasing practices. So even if in the case of the 2005 PGA Avista was "saved" in terms of its weighted average cost of gas (WACOG) by Katrina and Rita, its lack of adherence to portfolio purchasing practices that seek diversity, balance, and flexibility in gas supply was the crucial issue in 2005 and now again in 2006. When commenting at the Public Meeting, Avista indicated that the Staff's

> "commitment going forward to revisit and to focus on hedging strategies, we're very glad that they're willing to do that and they're committed to do that and we're also fully committed to working with Staff and other parties going forward to figure out what is the best way to do this, both in terms of <u>how much you hedge</u> [emphasis added], when do you hedge going forward so that customers will get the lowest possible price as well as some price stability going forward." Audio file of September 22, 2005, public meeting.

Clearly, Staff stated concern for and was critical of the company's hedging strategy as early as last year. Even though the company's strategy last year saved customers from even higher gas prices, we cannot and do not simply look at the results in making our recommendations today.

Avista's portfolio for 2005-2006 and now 2006-2007 is significantly different from its historical portfolio as demonstrated in the table below taken from the "**Public Utility Commission of Oregon Natural Gas Procurement Study"** published in 2005. During the period between 1999 and 2004 Avista never financially hedged more than 37% of its gas supply, and never fixed the price through both physical (storage) and financial hedging of more than 38% of its annual gas supply need. Those levels in the 2005-2006 and 2006-2007 PGA filings are 93% and 94%, and 91% and 92%, respectively.

Table E.1. Avista Natural Gas Purchases, PGA Years 1999/2000 through 2003/2004 (percent of total).

Strategy	**99/00**	**00/01**	**01/02**	**02/03**	**03/04**
Hedged Volumes	37	34	36	36	36
Jackson Prairie Volumes	1	1	1	1	1
First-of-the-Month (FOM) Volumes	62	65	63	63	63
Total	**100**	**100**	**100**	**100**	**100**

Avista's hedging strategy <u>today</u> is different in its three jurisdictions and between it and the other two LDCs in Oregon. Avista's hedging strategy looms large in why the company's WACOG is higher than those of the other two LDCs. One reason, according to Avista, is that the company has only recently incorporated "an amount of longer-term hedges into its purchase portfolio to provide an additional degree of rate stability in the future." The other two LDCs have long had physical or financial hedges of greater length than one year. In addition, the company explained that the amount of storage it has available as a physical hedge is considerably lower than either of the other two LDCs—supplying only 1% of its Oregon customers' load requirements. Most telling, however, is that the company claims that the "90%/10% sharing mechanism in Oregon . . . creates an incentive for utilities in Oregon to hedge additional loads . . ." The company further indicated that "with the removal of the sharing component, the company would reduce the level of hedging in Oregon." *From Avista's October 10, 2006, e-mail response to Staff data request*. This statement indicates that Avista's purchasing strategy for Oregon is designed to reduce the company's risk rather than achieving an appropriate hedging level.

In contrast, in other jurisdictions the company has employed a far different strategy on behalf of its customers. While Avista hedged 91% of its Oregon load requirements and thereby locked-in those prices to its customers, it hedged significantly lower levels in Washington and Idaho (less than 70%, including storage) and was able to substantially reduce its gas costs in Washington and Idaho because it was able to purchase additional lower-cost natural gas as prices fell in September. Its hedging strategy in those states was both more flexible and spread over a longer period of time. Avista's amended filing in Washington lowered its rate request from an 8.1 percent increase to a 1.3 percent increase, while in Idaho the company's rate request changed from a 3.2 percent increase to a 2.0 percent decrease. The company's hedging level and procurement strategy in Oregon is a major factor in the higher rates Oregon customers face this year.

The following tables show the dramatic differences between the company's PGA filings in Oregon (as described herein), and the filings the company made in Washington and Idaho. The information presented in these tables is disconcerting from the vantage point of the Oregon PGA for several reasons.

1. Even with the advantage of greater storage, Avista intends to financially hedge a maximum of 80% of annual gas sales in Idaho and Washington. This is the maximum level of financial hedging Staff believes is appropriate for Avista in Oregon as discussed in this memo.
2. At the time of the initial PGA filings in Idaho and Washington, Avista proposed to financially hedge about 66% of its annual gas sales. Increasing this level to compensate for the lesser access of Avista to storage in Oregon would be prudent, as would capping the increase at the maximum hedging level Avista proposed for both Idaho and Washington, 80%.
3. The timing of the execution of the hedges in Idaho and Washington is also worth noting. In both Idaho and Washington, the level of hedging already completed at the time of Avista's PGA filing was about 60%, leaving some room for additional

hedging after the filing or for gas purchases at index (spot) prices. In Oregon, the level of hedging already completed at the time of Avista's PGA filing was about 91%, leaving virtually no room for additional hedging after the filing or for gas purchases at index (spot) prices.

4. Finally, what does the lack of flexibility in the gas supply portfolio Avista filed in Oregon vs. Washington and Idaho mean in terms of customer costs? In its Idaho and Washington PGA filings Avista notes, "[h]owever, with the recent sharp drop in forward prices, and volatility of the wholesale natural gas market, the Company believes it is prudent to execute these additional hedges at these lower prices." Avista had this opportunity in Washington and Idaho only because at the time of the PGA filings in those states the company had financially hedged only about 60% of its expected gas sales. In Oregon Avista removed this opportunity when it chose to financially hedge about 91% of its expected gas sales, and its Oregon customers are expected to pay the price for that lack of flexibility in Avista's Oregon gas supply portfolio.

Avista PGA Flings in Washington and Idaho

Washington	
Filed Item	**Rate Impact**
Revenue impact	The proposed tariff sheets have an effective date of November 1, 2006 and will result in an estimated revenue increase of approximately 1.3% or about $2.7 million. As reflected in this filing, there is a $3.7 million *decrease* resulting from a proposed decrease in the weighted average cost of gas (WACOG) as compared to the WACOG reflected in present rates, and a $6.4 million *increase* related to the recovery of deferred gas costs. (PGA filing cover letter, p. 1)
WACOG	In the Company's original PGA filing, it used natural gas prices as of August 16th to price unhedged volumes for the forthcoming year (Nov. '06 – Oct. '07). Since that time, forward prices for the forthcoming year have fallen over $2.00 per dekatherm (20 cents per therm). In this filing, the Company has used forward prices as of September 21st to price unhedged volumes. The result is a proposed WACOG of $0.76357 reflected in this filing, as compared to a proposed WACOG of $0.849 reflected in the Company's original filing. (PGA filing cover letter, p. 1)

Washington	
Filed Item	**Rate Impact**
Hedging Explanation	**The Company has hedged approximately 60% of its estimated annual gas sales for the forthcoming year.** It will hedge an additional 20% of estimated sales within days of this filing. The Company has not executed these hedges as of the date of this filing as forward market prices have continued to fall. As the first sign of an increase in forward prices, the Company will execute these additional hedges. **This hedge level of approximately 80% of estimated customer requirements is higher than the Company's planned level of approximately 66% prior to September.** However, with the recent sharp drop in forward prices, and volatility of the wholesale natural gas market, the Company believes it is prudent to execute these additional hedges at these lower prices. The Company has discussed these additional hedges with the Commission Staff. **Further, if forward prices for this winter continue to fall, the Company will continue executing additional hedges beyond the 80% level. In that case, the Company will again contact the Commission Staff prior to executing these additional hedges.** (emphasis added) (PGA filing cover letter, p. 1)
Portfolio	Financially hedged – 80% (60% at time of PGA filing) Storage – not able to discern from the available information Index priced – not able to discern from the available information

Idaho	
Filed Item	**Rate Impact**
Revised Filing	
Reason for re-filing	The primary reason for this substitute filing is to revise the Company s proposed weighted average cost of gas (WACOG) to reflect a recent fall in wholesale natural gas prices. (PGA filing, p. 1)
Residential bills	The average residential customer using 65 therms per month will see their monthly bill decrease approximately $2.70 or about 3.4%, from $80.43 to $77.73 per month. The requested rate changes will have no effect on the Company s net income. (PGA filing, p. 1)
WACOG	The Company s present WACOG included in its gas sales rates is 78.600 cents per therm ($0.86485, total), which was approved by the Commission in Order No. 29902. The WACOG proposed in this requested increase is 76.244 cents per therm ($0.83938 total). The proposed WACOG of 76.244 cents per therm represents a decrease of approximately 2.4 cents per therm, or about 3.0%, over the present WACOG of 78.600 cents per therm. (paraphrase by Staff based on original PGA filing)

Idaho	
Filed Item	**Rate Impact**
Hedging Explanation	**The Company has hedged approximately 60% of its estimated annual gas sales for the forthcoming year.** It will hedge an additional 20% of estimated sales within days of this filing. The Company has not executed these hedges as of the date of this filing, as forward market prices have continued to fall. At the first sign of an increase in forward prices, the Company will execute these additional hedges. **This hedge level approximately 80% of estimated customer requirements is higher than the Company planned level of approximately 66% prior to September.** However, with the recent sharp drop in forward prices, and the volatility of the wholesale natural gas market, the Company believes it is prudent to execute these additional hedges at these lower prices. The Company has discussed these additional hedges with the Commission Staff. **Further if forward prices for this winter continue to fall, the Company will consider executing additional hedges beyond the 80% level. In that case, the Company will again contact the Commission Staff prior to executing those additional hedges.** (emphasis added) (PGA filing, p. 5)
Portfolio	Financially hedged – 80% (60% at time of PGA filing) Storage – 9% Index priced – 11%
Original Filing	
Residential bills	The average residential customer using 65 therms per month will see their monthly bill increase by approximately $2.41 or about 3%, from $80.43 to $82.84 per month. The requested rate changes will have no effect on the Company s net income. (PGA filing, p. 1)
WACOG	The Company's present WACOG included in its gas sales rates is 78.600 cents per therm, which was approved by the Commission in Order No. 29902. The WACOG proposed in this requested increase is 84. 712 cents per therm. The proposed WACOG of 84.712 cents per therm represents an increase of approximately 6.1 cents per therm, or about 7.8%, over the present WACOG of 78.600 cents per therm. (PGA filing, p. 5)
Portfolio	Financially hedged – 66% (at $0.873/therm – same as Oregon) Storage – 9% Index priced – 25%

Avista's hedging strategy is not a new concern to Staff as we noted in our 2005 PGA memo for Avista our multiple and serious concerns about the LDC's natural gas purchasing approach and the results of that approach:

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 (2005) [parenthetical date added for clarity] 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. *Avista Utilities 2005 PGA Filing at page 14.*

In its response to Staff's recent data request, Avista stated that "Staff at no time raised concerns with the level of hedging until after Avista filed its PGA request and all hedging had been completed." Staff disagrees with the company's assessment; we believe that staff clearly indicated our concerns with the company's hedging strategy in both last year's PGA filing (as the company's comments acknowledged) as well as individual meetings with the company over the past year. However, the central issue is not whether staff sufficiently conveyed its position to the company. Prudence of an LDC's purchasing strategy is not dependant on staff or the Commission instructing the utility what to do. Instead, prudence should be based on an examination—after the fact and without the benefit of hindsight—of what actions the company took and whether those actions were prudent based on information available at the time. The company is solely responsible for justifying whether its strategy was prudent.

Staff met with Avista Utilities twice in the last year to specifically discuss supply-side and demand-side acquisition strategies. In addition, we discussed portfolio strategies and management in a number of informal workshops as we had committed to do last year. Staff had not yet opened a formal investigation, but it was obvious earlier this summer that no informal agreement between the LDCs, Staff, NWIGU and CUB could be made regarding the appropriate sharing percentage in the PGA mechanism, at least in time for the 2006-07 PGA year. Staff continues to believe that while the current sharing percentage that Cascade and NW Natural are subject to (these companies share differences between actual and embedded natural gas costs on a 67/33 basis) could alter those companies' purchasing strategies, it appears that Avista Utilities' current sharing percentage of 90/10[4] also plays a significant role in its financial hedging strategy, which Staff believes is inappropriate. The sharing percentage component of the PGA mechanism is not meant to provide an incentive to hedge more, but rather to have the LDCs have a stake in doing the best job in purchasing natural gas during the PGA year. Under Avista's interpretation of the sharing mechanism, both Cascade and NW Natural should have a greater "incentive" to hedge more simply because they have a greater risk associated with incorrect embedded gas costs.

[4] Avista's sharing percentage is higher than the other two LDCs. This is a result of a negotiated settlement with the company after the company discontinued its experimental Gas Benchmark Mechanism. It was meant to be a temporary sharing percentage, subject to change when the informal and/or formal PGA mechanism review was completed. Avista also is subject to a fall earnings review under OAR 860-022-0070(8).

Staff also recommended in that 2005 memo that Avista work with and provide regular reports to Staff in the following areas:

1. If possible, Avista should look to add more and more flexible pricing options to its supply contracts (e.g., index changes, flexible MDDV, 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.

Since the time of the 2005 Staff Report, Avista has tackled some of these issues. However, based on our review, it appears that Avista has made only limited progress in addressing these issues.

1. Avista's pricing strategies remain largely inflexible. Avista itself describes its hedging process as "mechanical." Also, the review of the process for possible updates based on changes in the natural gas market is slow and cumbersome, and is clearly not dynamic.
2. Avista continues to utilize informal bidding for both financial hedges and gas supply.
3. Avista has not yet investigated any purchasing partnership arrangements.
4. Avista has entered some 3-year financial hedges for natural gas but has not yet sought to enter longer-term natural gas purchase contracts. LNG and purchasing unconventional natural gas directly remain longer-term IRP scenarios.
5. Avista appears to be working to improve the coordination of energy efficiency programs, demand-response, buy-back contracts, and gas purchasing.

Staff remains concerned that Avista's gas supply portfolio violates the basic tenets of portfolio purchasing and thus is inappropriate. The three goals of portfolio purchasing are diversity, flexibility, and balance. The level of financial hedging by an LDC should reflect the levels of price and operational risk facing the LDC. As those levels increase then financial hedging should increase also to help mitigate these risks. Severe levels of risk for an LDC are the result of extreme limitations in purchasing, transportation, and/or pricing options. The extreme case is an LDC that can purchase from only a single supply source, transport on only one pipeline (or even more limiting only one segment of one pipeline), has no or very limited access to storage, and has few or even no competitive options in the pricing for gas supply. Such an LDC should attempt to financially hedge all of its gas supply. LDCs facing fewer limitations should accordingly limit financial hedging to a level that directly reflects the level of limitations, and thus risk, they face. Based on these circumstances, Staff believes that an LDC of the size and operating under the circumstances of Avista should financially hedge no more than 80% of its gas supply. And even this 80% is the outer extreme for an LDC such as Avista. Because Avista's portfolio has already fixed the price of 91% of its gas supply through financial hedging, that portfolio is not diverse, flexible, or balanced.

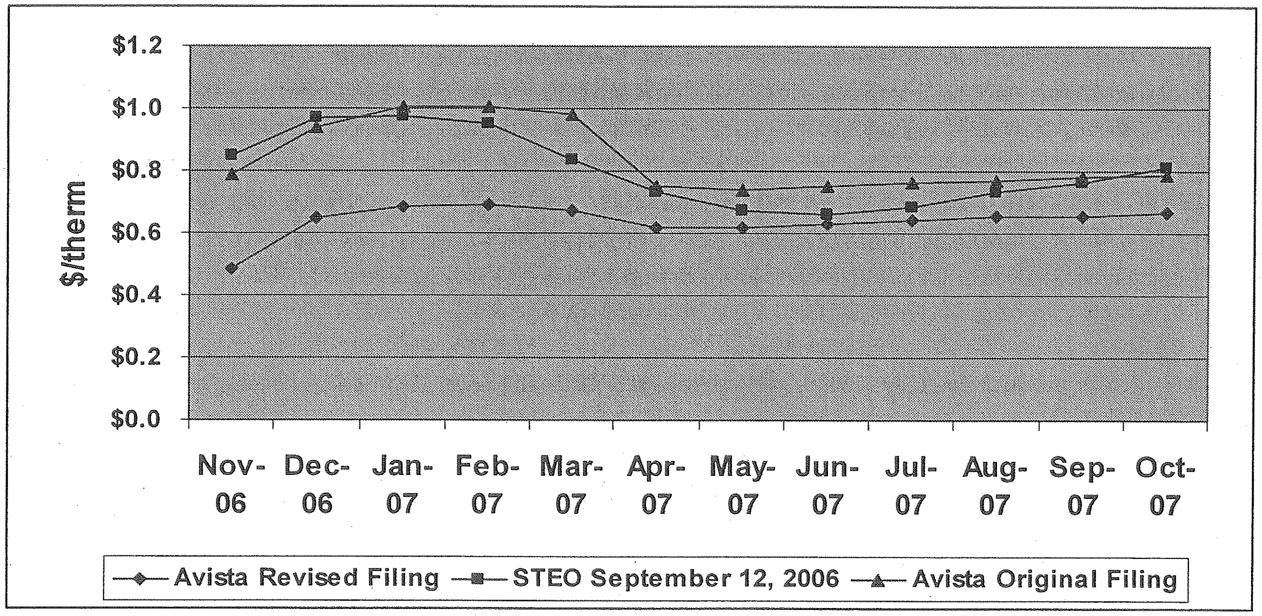
But the overuse of financial hedging can itself create a limitation for the LDC but one that constitutes a risk only for the LDC's customers. An LDC that commits to a level of financial hedging beyond the limitation and risks it actually faces reduces, and can in fact remove, flexibility from its portfolio while also severely damaging the balance and diversity of the portfolio. As financial hedges fix the price of an ever larger share of an LDC's portfolio, the ability of the LDC to respond to favorable changes in price, transport opportunities, purchasing location, contract type/length, etc. is reduced or eliminated. Customers of the LDC thus end up with a fixed price well above current natural gas prices that neither they nor the LDC can mitigate. Portfolio purchasing practices are also appropriate even in the reverse situation. The protection provided by these practices, by a balanced, diverse, and flexible portfolio, remain even where the price for the hedges is less than actual prices in the future. The future price of natural gas cannot be forecasted accurately on a consistent basis. Thus, the only protection a purchaser of natural gas for actual end-users has against future changes in natural gas prices, in whichever direction, is to not, as the old adage recommends, "put all your eggs in one basket." Portfolio purchasing accomplishes this objective. The LDC that fails to follow the tenets of portfolio purchasing has in simple terms so reduced the flexibility, balance, and diversity of its natural gas portfolio that it now only has one option for purchasing—the hedged price gas supply it has committed to. If that hedged price is lower than future actual prices for natural gas, the end-users win. If that hedged price is higher than future actual prices for natural gas, the end-users lose. But the results of winning and losing are not symmetrical. The price for future natural gas is not likely to drop below about $3.00/MMBtu under expected market conditions. On the other hand, the upper limit of this market is, as we've already seen, $15.00/MMBtu and perhaps even higher. Portfolio purchasing protects end-users from this asymmetry. There is no algorithm for computing the precise level of financial hedging an LDC should enter into. However, the general rule of thumb follows the above logic—the hedging level should be a response to a specific level of assessed operational and supply risk.

Avista has provided no compelling or even indicative evidence that its decision to enter financial hedges for over 90% of its required volumes is a response to a level of risk that justifies that level of hedging financially. During the upcoming workshops on the PGA the appropriate level of financial hedging and the related criteria will be discussed further. Staff hopes those workshops will lead to a specific agreement on appropriate hedging levels for LDCs of various sizes and circumstances.

Staff has other concerns about Avista's gas supply portfolio. First, the overall cost of Avista's financial hedging appears too high, based on the data available to Staff about the pricing for financial hedges during the period January 2006 to August 2006. The overall WACOG for the hedges entered into by Avista is $0.87342/MMBtu. Based on the actual futures prices available for hedges during the first eight months of 2006, Staff has projected what would be a reasonable overall price for hedges entered into during the period from January to August 2006. That price is $0.83020. The average price for hedges entered into over that period by NW Natural and Cascade are below that price. Avista has failed to explain or provide documentation for the higher level for its overall hedged price other than that it received multiple phone bids for hedge prices and accepted the bid that was the lowest while best meeting the needs of Avista's system and demand. As of the time of the writing of this memo, specific documentation had not been provided by Avista as to the sources of the actual prices at which hedges were entered, the actual conversation with "hedge bidders," or the specifics of the decision-making in accepting and rejecting hedging bids. Avista provided enough general documentation and data, however, that Staff has developed at least a general understanding of how Avista's hedging process actually functioned and how the overall price for the hedges entered came about. Although at this point Staff is still unable to fully explain the difference, Staff accepts the company's justification within the context that the upcoming workshops may provide specific standards, guidelines or criteria for determining the appropriate hedge price.

Second, Avista's projection for future spot (cash) prices, for natural gas the company may purchase for the 8% of its portfolio that is not financially hedged or already in storage at a known price, was, prior to the Company's re-filing, too high and was based on a single NYMEX "strip" for the PGA year. In the re-filing, the level of the forecast was reduced but the methodology for creating the forecast was not changed. Under current circumstances using a NYMEX strip or even an average of NYMEX strips to project spot natural gas prices will inevitably lead to a forecast biased toward the high end. This is the case because NYMEX prices have a premium built into them, usually referred to as an "insurance" or "risk" premium. Spot prices have either no premium or one much smaller than the one included in NYMEX prices. Currently, the NYMEX risk premium is estimated at approximately $2.00/Dth. So basing the forecast of spot prices on a

NYMEX strip is a methodological error that leads to the too high cost projection for spot prices made by Avista. Spot price forecasts may certainly incorporate NYMEX pricing signals, but in addition should integrate several reputable fundamentals forecasts of spot prices, supply, and demand from government and private fundamentals natural gas forecasts. Avista has not yet developed this necessary integration as it would apply to Avista's particular operational and financial circumstances. Avista's spot price forecasting methodology, as described by the company, is not appropriate and would tend to overstate the level of future spot prices. However, since the revised spot forecast is actually now below reputable fundamentals forecasts of future spot prices, the issue now arises as to whether Avista, by relying wholly on NYMEX strips for spot price forecasting, has understated the value of future spot prices. Fundamentally, the use of NYMEX forward prices as a forecast of future spot prices is problematic under any circumstances. Staff hopes to move Avista away from this practice. While Staff accepts Avista's spot prices for this filing, the forecasting of future spot natural gas prices for the PGA will be fully investigated in the upcoming PGA workshops, with the intent of developing criteria all LDCs can adhere to when forecasting spot price natural gas prices for their PGA and IRP filings. The graph at the top of the next page presents Avista's original and revised spot price forecasts along with the most recent of future spot prices for the EIA Short-Term Energy Outlook.



Avista's Natural Gas Costs

In its 2005 PGA public meeting memo for Avista, Staff noted that Avista's proposed PGA WACOG was noticeably higher than the other LDCs and presented reasons supporting either a partial or full denial of excess cost recovery for Avista. Ultimately Staff recommended the WACOG as filed be approved, but also recommended the following:

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.

Staff's assessment of Avista's progress in satisfying these recommendations is mixed.

- Avista now has a long-range purchasing and risk-management strategy but it is still in the "testing" phase, needing monitoring and modifications as it is actually implemented. Internal controls for the purchasing process have been improved, but still do not include full documentation of decision making or detailed accounts of the decision making process.
- Research and analysis of market intelligence remains fragmented and inadequate. Avista apparently establishes a procurement plan at the beginning of the purchasing season. That plan can be changed only by the action of the "Strategic Oversight Group," which meets only monthly. Any changes to the plan must then be approved by senior management. This is a cumbersome and, even more important, overly slow process. In today's natural gas market, an LDC must respond both quickly and thoughtfully to market changes that could occur daily or even on an intra-day basis. Avista needs to find a process that allows it to make such responses. While approval of senior management is important from a control and oversight perspective, that process for approval must allow changes to procurement necessary to respond

timely to market dynamics. Another concern is the review of market intelligence by Avista. While Avista has indicated it reviews market intelligence, it has not given details on how that review occurs, who actually does the review, and how that review directly and indirectly impacts the gas procurement process, despite several requests from Staff that the company provide such documentation.

- Avista continues to financially hedge significantly less in Washington and Idaho than in Oregon, apparently due primarily to Oregon's PGA requirement for sharing between customers and the company of differences between the PGA WACOG and the actual WACOG for each month. As we pointed out last year, this is an inappropriate reason for differences in portfolio design. *Avista Utilities 2005 PGA Filing at page 14.* Avista is unable to cite other differences between the states that could justify a significant difference in the financial hedging levels for the states. Avista has pointed out, correctly, a difference in access to storage in Oregon vs. Idaho and Washington. In Oregon about 1 percent of supply is expected to come from storage, while in Idaho and Washington this level is expected to be 8%-9%. This difference would justify some additional financial hedging in Oregon. As already noted above, Avista's proposed level of financial hedging in both Idaho and Washington was 60-66%[5] at the time of the PGA filings in those jurisdictions. Compensating for the lesser access to storage in Oregon would justify a 10% increase in this level to 76%. Staff believes an appropriate level is 80% [see page 17 of this memo], but Avista actually executed hedges prior to filing its Oregon PGA for about 91% of its expected Oregon gas needs.
- It appears based on the purchasing materials and documentation presented in Avista's 2006 PGA filing, the company's purchasing and risk-management strategy is still not fully"...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." Some progress has been made but the multiple concerns raised in this memo indicate Avista has not yet fully mastered the details of portfolio purchasing and the design of a portfolio based on the need for balance, diversity, and flexibility.
- Avista has participated fully in workshops regarding the PGA mechanism. As noted above, the informal workshops did not result in an agreement between the parties. Staff plans to open a formal review of the PGA mechanism later this year.

For the time during which Avista purchased gas for the period November 2006 through October 2007, the average cash (spot) price in the Northwest was approximately $5.80/MMBtu, with prices declining through almost the entire period. The NYMEX price

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[5] Avista increased this to 80% only in revised PGA filings, in an effort to take advantage of the continuing fall in futures natural gas prices.

closed the period (September 2006) at about \$8.80 (\$8.00)/MMBtu for the PGA year,[6] with prices also declining over most of the period since January 2006. The 2006-2007 winter NYMEX strip ended the period at about \$9.50 (\$8.70), but ranged between \$11.00 (\$10.20) and \$9.40 (\$8.60) per MMBtu for the winter months of 2006-2007.

For the current PGA, Avista proposes to pass through to its sales customers an average natural gas cost of \$0.85727/therm (\$8.57/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 \$0.88334 (\$8.83/dekatherm (MMBtu)). When fixed delivery costs are added the WACOGs are \$1.06514 (\$10.65/Dth) and \$1.09773 (10.98/Dth) sensitized. This pass through proposal stands out when compared with the sales WACOGs proposed by the other LDCs, Cascade and NW Natural. The proposed WACOGs are approximately 13% higher than those proposed by NW Natural and Cascade. The overall revenue increases proposed by Avista are \$5,984,931 for natural gas commodity and \$4,656,062 for natural gas transportation, totaling \$10,640,993.

At the end of June 2006 both interstate pipelines Avista transports on filed general rate cases at the Federal Energy Regulatory Commission (FERC). Northwest Pipeline (NWPL) requests a rate increase of about \$119 million, mostly related to rate base additions and an increase in its rate of return. Gas Transmission Northwest's (GTN) filing would nearly double its current rate for firm transportation. GTN also requests market-based rates for full haul interruptible transportation and a sharing of costs for turned back capacity. It has been over ten years since either company filed a general rate case at the FERC. The LDCs and Staff have agreed to place the full rate increase requested by both pipelines into the filed PGAs, subject to refund based on the actual rates finally approved by the FERC. For this reason, Staff has not analyzed the transportation portion of the increase in Avista's PGA filing except to ensure the increase fairly reflects the rates proposed by the two interstate pipelines.

Based on the history of prices in the Northwest and the general practice of purchasing over the period between April/May and September during the year, Staff has calculated WACOGs for Avista of \$0.83156(\$8.32/Dth) and \$0.83262 (\$8.33/Dth, revenue-sensitized). Adding fixed delivery costs the WACOG are \$1.03943 (\$10.22/Dth) and \$1.04197 (\$10.24/Dth, sensitized). In calculating this WACOG, Staff made only one adjustment to Avista's filed PGA. Staff reduced the level of financial hedging in the PGA from the approximate 91% filed by Avista to 80%. And even with these reductions Avista's WACOGs would remain about 8%-10% higher than those proposed by Cascade and NW Natural. The revenue increases associated with these Staff-calculated

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[6] Prices in parentheses are estimated Northwest prices based on an average basis difference from national price of (\$0.80).

WACOGs are approximately $3,572,000, for natural gas commodity and $4,656,000 for natural gas transportation, totaling approximately $8,228,000. Staff's adjusted cost increase is about $2.41 million less than the increase proposed by Avista.

Staff's adjustments to Avista's proposed WACOGs are based on the concerns explained above under the discussion of Avista's Natural Gas Purchasing Strategies. In summary, we believe the company's proposed WACOG is not justified because the company has financially hedged an imprudent amount of its volumes, with inadequate support for its strategy. As discussed above, several factors lead Staff to this conclusion:

- First, in order to create a gas supply portfolio that is flexible, diverse, and balanced, portfolio purchasing practices must be adhered to in all instances. Otherwise the LDC becomes a speculator attempting to guess the direction and level of future natural gas prices. Avista has violated this basic rule by creating a supply portfolio that is imbalanced, inflexible, and clearly not diverse due to the over reliance on financial hedging.
- The gas supply portfolios proposed by Avista in Idaho and Washington meet the requirements of portfolio purchasing. The result is a balanced, diverse, and flexible gas supply. In its Idaho and Washington PGA filings, Avista is not overly dependent on financial hedging as it is in its proposed Oregon PGA.
- It appears the price of the hedges Avista entered into prior to filing its PGAs in Idaho, Washington, and Oregon is the same, $0.8734/therm. As Staff has already indicated, this price seems high based on the data and information available to Staff about the prices for hedges in 2006 through August. However, Staff is willing to accept the explanations offered by Avista for this difference. But because of Avista's over-reliance on financial hedging for its Oregon gas supply, this price applies to 91% of the company's expected sales in Oregon. In Idaho and Washington this price applies only to about 60% of expected sales in those states, and some of the impacts of this higher price may even be offset by lower priced financial hedges Avista proposes to enter into after its PGA filing in those states.
- Finally, Avista has attempted to justify its over-reliance on financial hedging in its Oregon PGA filing by claiming the sharing component of the Oregon PGA forces the company to enter into hedges at this higher level in order to protect its revenues. As Staff has pointed out, this is an inappropriate reason for differences in portfolio design. While protecting revenues is an appropriate goal for an LDC to pursue, it is not appropriate to pursue that goal through the PGA or gas supply

portfolio design. Gas supply portfolio design should focus on diversity, balance, and flexibility, as required by portfolio purchasing, and as pointed out to Avista by Staff in both the 2005 PGA memo and in subsequent workshops.

Staff and Avista met several times after the company made its original filing in late August, and by teleconference over the last several weeks. Avista has not been willing to reduce its WACOG to a level Staff believes is more appropriate. The Commission does not have the option to simply reject the company's filing, but rather must either order the suspension of the tariff sheets, pending an investigation pursuant to ORS 757.215, or under Section (4) of that statute, approve the tariff sheets subject to refund.

Staff recommends that the PGA WACOGs proposed by Avista be allowed to go into effect on November 1, 2006, but with the revenues collected as a result of the WACOG increase from 2005 subject to refund. Staff also recommends that an investigation be opened and a prehearing conference be scheduled soon to set a procedural schedule for matters related to the investigation. The investigation would provide another opportunity for Avista to justify its revenue increase request associated with the proposed WACOG and why the increased revenue should not be disallowed and refunded to the customers from whom it will be collected, and why its proposed WACOG is more reasonable than the WACOG proposed by Staff. This recommendation would allow the changes related to non-commodity costs to go into effect, as well as the various temporary increments—only the commodity cost increase portion of the company's request would still be in dispute.

There are two other options the Commission may consider with regard to the disposition of the company's request for approval of its tariff sheets:

- Approve the company's request in its entirety. Under this alternative, the tariff sheets would go into effect on November 1, 2006, as filed. Staff does not believe that Avista has adequately supported its WACOG increase, and therefore, this option seems untenable.
- Suspend the entire filing, and initiate an investigation into the company's filing to include a hearing before the Commission after discovery and testimony. This option is also not very practical because many of the elements of the company's filing are undisputed.

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.

Avista's proposed filing requests an amortization rate of 6.843 cents per therm to recover net costs in the PGA deferral accounts over a two-year period as well as to recover the estimated DSM account balances over a three-year period and the balance of the state-mandated weatherization program over one year. Given the magnitude of the overall proposed increase requested in Avista's filing, a two-year amortization of the PGA account balances reduces the impact from 11.9 percent with recovery over a one-year period to 6.9 percent over a two-year period. Staff believes Avista's proposal for amortization is reasonable.

Earnings Review and Three Percent 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). In 2002, the Commission approved Avista Utilities request to renew its GBM for a three-year period ending March 31, 2005.

In 2005, Staff and Avista agreed upon a sharing mechanism of 90/10. 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. On August 31, 2006, Avista filed proposed new Schedules 461, 461A, 461B and 461C, Purchased Gas Cost Adjustment Provisions - Oregon, in Advice No. 06-06-G. These schedules are a temporary PGA mechanism, the terms of which reflect numerous discussions between Staff and the company. As set forth in the tariff, the company will defer 90 percent of the difference between its monthly actual and estimated commodity cost of gas.

In Avista's 2005 PGA filing, Staff and the company agreed-upon a reduction in Avista's earnings threshold from 300 to 200 basis points above the company's adjusted[7] return on equity. Staff proposes to adhere to this agreement in the 2007 spring earnings review. For the 2006 spring earnings review, Avista's earnings threshold as determined by Staff was 12.37 percent. The company calculated its ROE for the 12-months ending December 31, 2005, as 11.54 percent prior to the application of its Type I and Type II adjustments. The company's ROE calculation fell below the earnings threshold of 12.37 percent authorized by the Commission; therefore, there was no sharing of earnings required in the 2006 spring earnings review.

The purpose of the fall earnings review is to determine whether or not Avista should absorb any of its deferrals. 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 natural gas utility's gross revenues for the proceeding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. To mitigate the overall impact of this rate increase, Avista proposes to amortize $7.6 million over a two-year period. The extended amortization period allows the amortization of gas costs to fall below three percent of Avista's gross revenues for the proceeding calendar year. Staff finds that the rate increase is just and reasonable and recommends the Commission adopt the increase pursuant to ORS 757.259 (7).

At the time of the fall earnings review in 2007, Avista has agreed they would be at risk for not amortizing the amount of deferrals accumulated from November 1, 2006, through October 31, 2007, or returning to customers 80 percent of the overearnings above the threshold, whichever is less.[8]

UM 1279

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 company also requested reauthorization of its deferral accounting for the reduction in margin for interruptible and transportation customers as set forth in Commission Order No. 03-570.

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

[7] The authorized return on equity is adjusted annually to reflect 20 percent of any change in the risk-free rate in order to determine the company's earnings threshold (see Order No. 04-203).
[8] See Order No. 98-543, Appendix A, Page 4.

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 reauthorization to use deferred accounting pursuant to tariff Schedule 461, effective November 1, 2006. Consistent with Commission Order No. 06-568, entered October 2, 2006, the company will not compute interest on the deferrals accrued for the period November 1, 2006 through October 31, 2007, until amortization begins November 1, 2007.

PROPOSED COMMISSION MOTION:

Avista Utilities' request for 1) amortization of deferred accounts be approved; 2) the associated tariff sheets in Advice No. 06-06-G Supplemental to go into effect with service on November 1, 2006, subject to refund, and the L.S.N. be approved; and 3) the company's request for reauthorization to use deferred accounting pursuant to Schedule 461 and for the reduction in margin for interruptible and transportation customers as set forth in Order No. 03-570, be approved. In addition, Staff's request to open an investigation pursuant to ORS 757.210 and 757.215 be approved.

Attachments

Avista 2006 PGA and UM 1279

APPENDIX

This Appendix contains figures, charts and narrative referred to in the main text of the Staff Report. It is an integral part of Staff's report and is included here to provide detail not specific to Avista's filing, but rather details of national and regional natural gas prices and markets, and information and date that apply to all three Oregon LDCs.

Current Cash (Spot) Price of Natural Gas

National. Price at the Henry Hub has declined significantly since December 2005. Prices at the Henry Hub ranged from $13 to about $10 during the final quarter of 2005. Cash prices have declined since that point. The price hovered near and actually dropped below $6.00 during the spring and summer of 2006 and was approximately $7.00 for August, before dropping below $5.00 during September. The price is forecasted to increase as winter approaches but is not expected to exceed $9.00, on average, for the winter season. This history is depicted in Table 4 and Figure 2 below (pages 6-7). A snapshot of the changes in price for cash (spot) natural gas is presented in Table 1.

Table 1 - Henry Hub Prices

Month	$/Dth (MMBtu)
October 2005	$13.71
November	$10.28
December	$12.99
January 2006	$8.76
February	$7.62
March	$6.88
April	$7.10
May	$6.23
June	$6.26
July	$6.05
August	$7.24
September	$4.95
October (as of October 9, 2006)	$4.19
AVERAGE (October 2005 – September 2006)	**$8.17**

Northwest Basis Difference. As it applies to the cash (spot) market for natural gas, basis is the difference between the national cash price (at the Henry Hub) and the cash price, for the time, place and quality where delivery actually occurs.

The cash price for natural gas in the Northwest US is directly influenced by the price at the Henry Hub, as this price reflects both domestic and world worldwide supply and demand factors. However, while Northwest US natural gas prices are heavily influenced by the Henry Hub prices, rising and falling generally in unison, they are seldom identical to the Henry Hub price. There is usually a difference in actual prices between the two market areas due to local variations in circumstances. This difference between the cash prices at the Henry Hub and the cash price at the Northwest hubs is called the basis. This basis reflects the supply and demand situation in the Northwest US market area and changes as local conditions change. Historically, the basis difference between the Henry Hub price and the price at the Northwest hubs has been negative, as the Northwest US does not utilize natural gas to the extent or frequency of much of the remainder of the country and has a large hydroelectric resource to rely on for a significant portion of its electric needs.

Average basis differential for 2006, through August, is negative $1.08/MMBtu. The differential in 2006 has varied, however between negative $0.75/MMBtu (February) and negative $1.39/MMBtu (April) through August. If, as Staff expects, natural gas prices across the country stabilize and perhaps even decline slightly from today's prices over the next year the Northwest differential is likely to decline, but remain negative.

Regional (various major trading hubs). As with the Henry Hub price, the prices at western and northwestern natural gas hubs have steadily declined since the beginning of the year, with only a modest up turn in August. The decline continues in September. This trend is clearly visible in Figure 2, with the actual average prices by month at most major western and northwestern hubs presented in Table 4. Most of the natural gas purchased by Oregon LDCs is purchased at the AECO, Sumas, and Rockies hubs. AECO's prices began the year at $7.48/MMBtu, declined to $5.10/MMBtu by July, before moving up slightly to $5.88/MMBtu in August. However, in September the price has declined to less than $4.50/MMBtu. The average price at AECO for the year through August is $5.85/MMBtu. Similar patterns are found at the Sumas and Rockies hubs. Sumas began the year at $7.71/MMBtu, moved up slightly in August to $6.13/MMBtu, before declining to less than $5.00/MMBtu in September. The average price at Sumas for the year through August is $5.61/MMBtu. The Rockies hub began in January at $7.30/MMBtu, turned up slightly in August to $6.02/MMBtu and declined in September to just over $3.50/MMBtu. The average price at the Rockies for the year through August is $4.99/MMBtu.

<u>Futures Price</u>

Like physical prices, the prices for natural gas futures on NYMEX have declined since last year's PGA filing, although not so much as the declines in physical prices. The history of these changes is depicted in Table 2 at the top of the next page.

Table 2 - Change in Futures Prices (NYMEX)

Month	October 2004	August 11, 2005	August 31, 2006
October 2005	$7.00	$11.00	
November	$7.00	$10.90	
December	$7.50	$11.70	
January 2006	$7.60	$10.90	
February	$7.60	$11.90	
March	$7.40	$10.60	
April	$6.25	$8.50	
May	$6.20	$8.20	
June	$6.10	$8.50	
July	$6.00	$8.60	
August	$6.10	$8.65	
September	$6.05	$8.60	
October			$6.05
November			$8.23
December			$9.98
January 2007			$10.63
February			$10.66
March			$10.48
April			$8.34
May			$8.19
June			$8.28
July			$8.39
August			$8.48
September			$8.57
October			$8.73
November			$9.70
AVERAGES	$6.73	$9.84	$8.91

The current basis difference between the futures at the Henry Hub and the futures prices in the Northwest is approximately $0.80 per Dth. When this difference is applied to the above NYMEX futures for the upcoming months the results are shown in Table 3.

Table 3 - Change in Futures Prices (Northwest)

Month	August 31, 2006
October	$5.25
November	$7.43
December	$9.18
January 2007	$9.83
February	$9.86
March	$9.68
April	$7.54
May	$7.39
June	$7.48
July	$7.59

Month	August 31, 2006
August	$7.68
September	$7.77
October	$7.93
November	$8.90
AVERAGES	$8.11

Gas Supply, Production, and Demand

In the early part of 2006, the EIA produced the data found in Figure 1 regarding expected US natural gas demand and supply. This data is still largely valid, as changes in expected demand have largely been offset by changes in domestic production, primarily in new onshore production in such places as Texas, the Rockies, and in deepwater offshore production. Imports from Canada are expected to decline, but it is expected that LNG imports will more than make-up for this loss. One of the main points of the Figure remains true—the US cannot now and is unlikely for the future to be able to meet its natural gas demand with domestic supplies alone. Conservation (designed or brought about by price) and weather (e.g., hurricanes, very cold winter) are primary factors in changing the supply-demand balance shown in Figure 1 below.

Figure 1 - EIA's Estimate of Expected US Natural Gas Demand and Supply

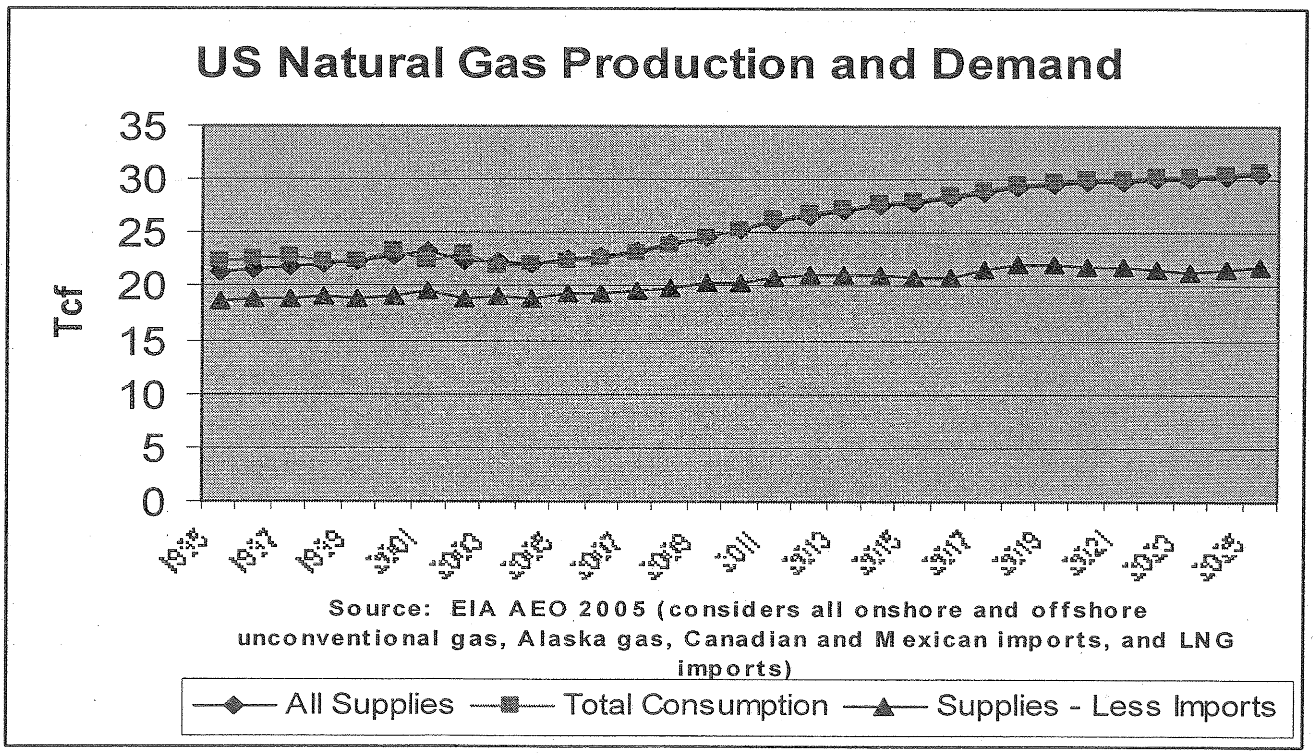
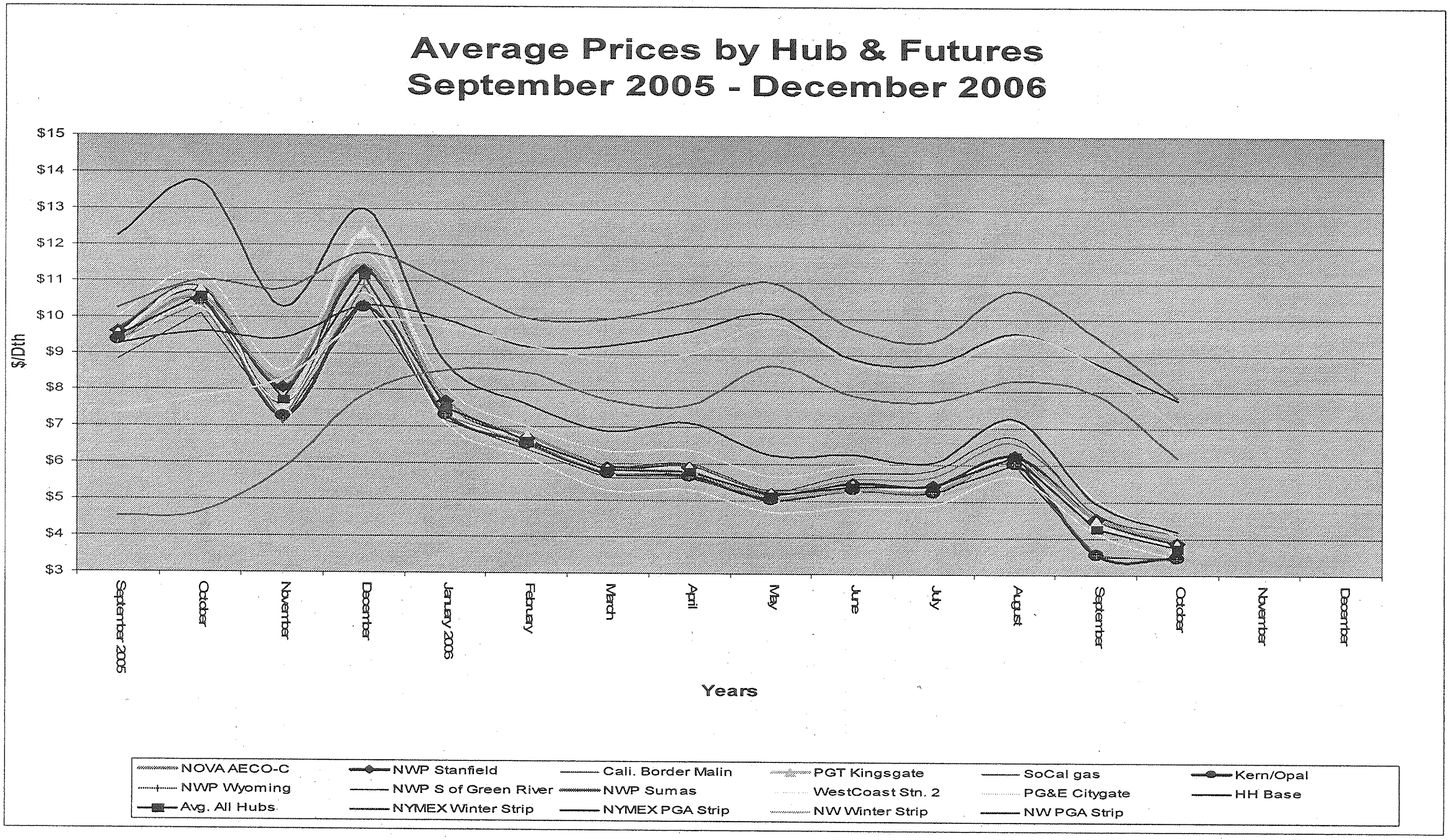


Table 4 – History of US Natural Gas Prices (Physical and Futures)

	Stanfield	Malin	Kingsgate	AECO	SoCal	Opal	Wyoming	S. of Green River	Sumas	Station 2	PG&E	Henry Hub	Avg. All NWP Hubs	NYMEX Winter Strip	NYMEX PGA Strip	NWP Winter Strip	NWP PGA Strip
September 2005	$9.61	$9.70	$9.50	$9.44	$9.65	$9.36	$9.33	$8.83	$9.38	$9.18	$10.02	$12.26	$9.45	$10.26	$9.25	$7.39	$4.52
October	$10.71	$10.83	$10.73	$10.54	$10.81	$10.46	$10.37	$10.09	$10.55	$10.26	$11.23	$13.71	$10.60	$11.03	$9.59	$7.83	$4.63
November	$8.06	$8.12	$7.49	$7.87	$7.58	$7.28	$7.15	$7.06	$8.27	$7.63	$8.54	$10.28	$7.73	$10.78	$9.42	$8.31	$5.84
December	$11.29	$11.37	$12.33	$10.79	$11.30	$10.29	$10.89	$10.47	$11.45	$10.67	$11.79	$12.99	$11.15	$11.79	$10.31	$9.82	$7.86
January 2006	$7.69	$7.76	$7.45	$7.48	$7.66	$7.34	$7.30	$7.17	$7.71	$7.08	$8.09	$8.76	$7.52	$10.96	$9.94	$9.75	$8.53
February	$6.69	$6.71	$6.72	$6.51	$6.79	$6.53	$6.52	$6.38	$6.78	$6.20	$7.00	$7.62	$6.62	$9.99	$9.19	$9.24	$8.49
March	$5.90	$5.94	$5.82	$5.73	$5.96	$5.75	$5.74	$5.61	$5.89	$5.26	$6.36	$6.88	$5.81	$9.97	$9.22	$8.86	$7.76
April	$5.91	$5.96	$5.88	$5.76	$6.00	$5.66	$5.65	$5.61	$5.77	$5.28	$6.37	$7.10	$5.80	$10.41	$9.63	$9.01	$7.62
May	$5.20	$5.28	$5.16	$5.07	$5.30	$5.04	$5.02	$5.02	$5.11	$4.67	$5.66	$6.23	$5.14	$10.99	$10.12	$9.84	$8.68
June	$5.47	$5.58	$5.41	$5.27	$5.75	$5.31	$5.28	$5.29	$5.33	$4.85	$5.97	$6.26	$5.41	$9.73	$8.89	$8.80	$7.88
July	$5.42	$5.67	$5.34	$5.10	$5.86	$5.24	$5.24	$5.24	$5.30	$4.90	$6.10	$6.05	$5.40	$9.39	$8.74	$8.55	$7.72
August	$6.25	$6.59	$6.14	$5.88	$6.76	$6.04	$6.02	$6.01	$6.13	$5.65	$7.16	$7.24	$6.24	$10.78	$9.60	$9.54	$8.30
September	$3.88	$3.90	$3.79	$3.57	$4.12	$3.48	$3.43	$3.47	$3.92	$3.48	$4.08	$4.19	$3.74	$7.84	$7.78	$7.03	$6.22
October																	
November																	
December																	
Average 2006	$5.91	$6.03	$5.83	$5.68	$6.10	$5.61	$5.60	$5.54	$5.85	$5.35	$6.43	$6.80	$5.81	$10.19	$9.35	$9.14	$8.08
Average 2005-2006	$7.14	$7.25	$7.12	$6.91	$7.25	$6.76	$6.78	$6.64	$7.10	$6.61	$7.65	$8.50	$7.02	$10.43	$9.44	$8.89	$7.35
Jan - Aug Strip Avgs.																$9.20	$8.12
Feb - Aug Strip Avgs.																$9.12	$8.06
Apr - Aug Strip Avgs.																$9.15	$8.04

Figure 2 – History of US Natural Gas Prices (Physical and Futures)



ORDER NO. 06-610
Attachment A

Avista Utilities
Oregon Gas Operations
Summary of Present and Proposed Rates
2006 PGA Tracking Application

Line No.	Description	Rate Sch	Adjusted Sales (Therms)	Revenues at Present Rates	PGA Gas Costs			Temporary Increments		Other Changes	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	51,273,139	$73,970,087	$2,808,743	$3,361,980	$6,170,723	($4,448,458)	$3,508,621		$0.10202	$5,230,886	$79,200,973
2	General	420	29,212,107	$37,688,766	$1,600,239	$1,915,438	$3,515,677	($2,534,442)	$1,998,984		$0.10202	$2,980,219	$40,668,985
3	Large General	424	4,331,166	$5,303,074	$237,261	$283,994	$521,255	($375,772)	$296,382		$0.10202	$441,865	$5,744,939
4	Emergency Instit.	430									$0.10202		
5	Interruptible	440	6,279,774	$6,378,052		$411,765	$411,765	($533,969)	$151,468		$0.00466	$29,264	$6,407,316
6	Seasonal (2)	444	179,251	$216,329	$9,819	$11,754	$21,573	($15,552)	$12,266		$0.10202	$18,287	$234,616
7	Special Contract	447	8,735,919	$334,340									$334,340
8	Firm Transportation	455											
9	Int. Transportation	456	31,377,917	$2,049,864									$2,049,864
10	TOTAL		131,389,273	$125,940,512	$4,656,062	$5,984,931	$10,640,993	($7,908,193)	$5,967,721			$8,700,521	$134,641,033

Attachment B

Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service
(November 2006 PGAs)

		RATE IMPACTS				BILL IMPACTS											
Class of Service	Rate Schedule	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	$1.34729	$1.44931	0.10202	7.6%	98	$5.00	$137.03	$147.03	$10.00	7.3%	52	$5.00	$75.06	$80.36	$5.30	7.1%
Cascade	101	$1.11833	$1.21082	0.09249	8.3%	117	$3.00	$133.84	$144.67	$10.83	8.1%	62	$3.00	$72.34	$78.07	$5.73	7.9%
NW Natural	2	$1.29167	$1.34052	0.04885	3.8%	109	$6.00	$146.79	$152.12	$5.33	3.6%	57	$6.00	$79.63	$82.41	$2.78	3.5%
Commercial																	
Avista	420	$1.26353	$1.36555	0.10202	8.1%												
Cascade	104	$1.01813	$1.11062	0.09249	9.1%												
NW Natural	3	$1.19803	$1.24436	0.04633	3.9%												
Industrial																	
Avista	424	$1.20711	$1.30913	0.10202	8.5%												
Cascade	105	$0.97832	$1.03535	0.05703	5.8%												
NW Natural	31	$1.15524	$1.21826	0.06302	5.5%												
Interruptible																	
Avista	440	$1.01565	$1.02031	0.00466	0.5%												
Cascade	170	$0.91482	$1.00732	0.09250	10.1%												
NW Natural	32	$0.93900	$0.99873	0.05973	6.4%												

Attachment C