ORDER NO. 08-523

ENTERED 10/30/08

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UG 185 & UM 1389

In the Matters of	)	
	)	
CASCADE NATURAL GAS CORPORATION	)	
	)	
Reflects changes in the cost of purchased gas and technical adjustments and makes adjustments to base rates for various programs (UG 185)	)	ORDER
	)	
and	)	
	)	
Request for an order reauthorizing deferred accounting. (UM 1389).	)	

DISPOSITION: APPLICATIONS APPROVED

On August 29, 2008, the Public Utility Commission of Oregon (Commission) received two applications from Cascade Natural Gas Corporation. 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 24, 2008, the Commission adopted Staff's recommendation to approve the applications.

ORDER

IT IS ORDERED that:

1. The amortization of deferred accounts, base gas cost changes and rate changes as requested in docket UG 185 are approved.

2. The associated tariff sheets of Advice Nos. O08-08-02 and O08-08-02-A are allowed to go into effect with less than statutory notice, beginning with service on or after November 1, 2008.

3. Reauthorization to use deferred accounting pursuant to Schedule 177 and Rule 19, as requested in docket UM 1389, for one year beginning November 1, 2008, is approved.

Made, entered, and effective OCT 30 2008.

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. 3 & 4

PUBLIC UTILITY COMMISSION OF OREGON
STAFF REPORT
PUBLIC MEETING DATE: October 24, 2008

REGULAR X **CONSENT** ____ **EFFECTIVE DATE** **November 1, 2008**

DATE: October 21, 2008

TO: Public Utility Commission

FROM: Ken Zimmerman, Lynn Kittilson and Deborah Garcia

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

SUBJECT: CASCADE NATURAL GAS: (Docket No. UG 185/Advice No. O08-08-02) Reflects changes in the cost of purchased gas and technical adjustments and makes adjustments to base rates for various programs.

CASCADE NATURAL GAS: (Docket No. UM 1389) Reauthorizes deferred accounting for the PGA deferral mechanism and other currently allowed deferred accounts.

STAFF RECOMMENDATION:

Staff recommends the Commission approve Cascade Natural Gas Corporation's (Cascade or Company) application for less than statutory notice (LSN) and allow the Company's tariff sheets in Advice Nos. O08-08-02 and O08-08-02-A to go into effect with service on and after November 1, 2008. This filing increases the Company's annual revenues by approximately $5.3 million, or 4.8%.

Staff also recommends Commission approval of Cascade's request for reauthorization to use deferred accounting pursuant to its Schedule 177, Purchased Gas Cost Adjustment Provision, and Rule 19, Conservation Alliance Plan Mechanism.

DISCUSSION:

On August 29, 2008, Cascade submitted its annual gas cost tracking and technical adjustment filing, commonly known as its PGA filing. The PGA allows Cascade 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. This filing consisted of a proposed increase in annual revenues of approximately $9.6 million or 9.1%, docketed as UG 185, Advice No. O08-08-02. In a concurrent filing docketed as UM 1389, Cascade requested reauthorization of deferred accounting under the Company's PGA mechanism and its Conservation Alliance Plan (CAP). On October 10, 2008, the Company filed replacement sheets in Advice No. O08-08-02-A, along with an LSN application, to lower its projected commodity cost and amortization rates for various temporary adjustments. The re-filed PGA requests an overall revenue increase of approximately $5.3 million annually, or 4.8%.

UG 185

In its amended filing, Cascade seeks approval to increase rates to: (1) track changes in purchased gas costs; (2) make a permanent adjustment to base rates for the Company's CAP; and, (3) make technical adjustments to amortize Cascade's deferred accounts including gas costs, earnings sharing, tax kicker refund and the CAP. The change in annual revenues is summarized in Table 1, below, and additional detail is shown in Attachment A.

Table 1: Change in Annual Revenues

PGA Base Gas Cost Change	$2,219,686
Removal of Prior Year Temporary Decrement	$2,971,372
Addition of New Temporary Increment	$280,923
Permanent Base Rate Adjustment (CAP)	($150,273)
Total Proposed Increase	$5,321,708

With these changes, the monthly bill of a typical residential customer using 59 therms per month will increase by $4.00, or 5.4 percent, from $74.32 to $78.32. In January, a typical residential customer's consumption of 113 therms will result in a billing increase from $139.60 to $147.25.

A summary that compares the impact of this year's proposed rate changes, on both an annual and January basis, for Cascade, Avista and NW 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 56 therms plus the monthly customer charge, divided by 56 therms. The graph shows that Cascade's residential customers have an effective rate of $1.33013 per therm, while Avista's and NW Natural's effective rates are $1.46094 and $1.52216, respectively.

Table 2 at the top of the next page shows the rates the Commission has approved for Cascade's residential customers on Rate Schedule 101 between 2004 and 2007, and the current proposal.

Table 2: Residential Rates 2004 – 2008 (Proposed)

Date	Customer Charge	Rate Per Therm	Percentage Change [1]
October 2004	$3.00	$0.97948	
October 2005	$3.00	$1.11833	14.2%
November 2006	$3.00	$1.21082	8.3%
June 2007	$3.00	$1.19900	-1.0%
November 2007	$3.00	$1.20884	0.8%
November 2008	$3.00	$1.27656	5.6%

Cascade's conservation programs are now provided by agreement with Energy Trust of Oregon (ETO). Low-income weatherization and bill payment assistance is provided by agreement with community service agencies. The Commission recently approved revisions to Cascade's Schedule No. 31 which allows current public purpose funding collected for low-income programs to be used entirely for low-income bill payment assistance through March 31, 2009. Specific information on these programs is readily available to customers on their monthly bills, by telephone, in person at the Company offices, on the Company's web site, and on the ETO web site.

Staff Review of Gas Costs

National and Regional Natural Gas Markets

Natural gas prices increased steadily from November 2007; peaking at just over $13/MMBtu at the Henry Hub spot market in June and on NYMEX in July. Since July, spot prices have declined about 45%, falling to between $7.00 and $7.50 per MMBtu in September. Likewise, NYMEX prices had declined to the $8.00 to $8.50 per MMBtu range by September. This is an approximate 40% decline in NYMEX prices since July. Pacific Northwest prices (both spot and futures) followed this trend, with a basis differential generally between ($1.00) and ($1.50) per MMBtu.

The conditions in the natural gas market over the last year include:

- The steady increase in natural gas price during November 2007 to July 2008, is generally attributed to two primary factors:
  - concerns about diminishing domestic reserves and production, and

[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 2008, when the rate per therm is combined with the monthly customer charge of $3.00, the average customer's bill is increased about 5.4%, as shown on Attachment B.

- the increase during that period in oil price. The oil price increase was attributed to continued growth in world and US demand, and financial speculation in oil markets.

- While total natural gas consumption is expected to increase by 2.7 percent in 2008 and by 2.2 percent in 2009, unlike past periods, domestic production is expected to increase by 7.8 percent in 2008 and by 3.8 percent in 2009.

- Concerns about declines in domestic natural gas reserves and production have been mitigated in the last few months by increases in unconventional domestic production and reserves from shale deposits. Currently, unconventional natural gas accounts for about one-half of annual US production, and is increasing. The fastest growing sector of unconventional production is gas from shale. Some estimates indicate at much as 118 years of reserves in shale gas alone. This is a dramatic departure from recent concerns about the continuous decline in domestic production and reserves.

- There are serious environmental concerns about unconventional production, particularly from shale deposits. These relate primarily to the use of and pollution of local water supplies. If validated, these environmental impacts may severely limit US unconventional natural gas production.

- Also, a supply based heavily on unconventional supplies will tend to keep pricing in the $7.00 to $10.00 range, as currently prices lower than $7.00 will generally make unconventional production unprofitable. Depending on the production site, unconventional supply is more expensive to bring to market.

- Along with the increase in domestic supplies, Canadian imports, at least for the time being, have increased. For the period November 2007 to September 2008, Canadian pipeline imports to the US have increased 20% for California, 14% for the Midwest, and 6% for the Pacific Northwest. Canadian pipeline imports to the Northeast US declined by 7.4%, however.

- Liquefied natural gas (LNG) imports remain sluggish, however; severely hampered by global LNG demand growth and higher relative prices in the Asia/Pacific region and Europe. For 2008, LNG imports are expected to total about 350 billion cubic feet (Bcf), a decline of more than 50 percent, or 420 Bcf, from 2007, and then to total about 450 Bcf in 2009 as new global LNG supply is added to the market. However, a new possibility has entered the LNG arena. Several natural gas production companies, particularly those producing the new shale gas wells, have begun to propose that the US become a net LNG exporter rather than net importer. Whether these proposals will gain traction and actually translate to changes in the direction LNG flows at US terminals is impossible to say at this time.

- The Henry Hub natural gas spot price averaged $7.17 per thousand cubic feet (Mcf) in 2007 and is expected to average about $9.70 per Mcf in 2008 and about $8.55 per Mcf in 2009. NYMEX futures (at the Henry Hub) averaged about $8.05 over the 2006-2007 PGA year, and about $9.50 for the 2007-2008 PGA year (through September 2008).

- Weather driven demand has not had a major impact over the last year. The winter of 2007-2008 was generally mild; placing little heating stress on supplies. Likewise, the summer of 2008 was mild in terms of the use of natural gas to generate electricity to meet cooling demand.

- Hurricane Gustav in August-September shut in about 6.1 Bcf/day (80%) of Gulf of Mexico (GOM) production. As of October 10, the Minerals Management Service (MMS) reported that 2.9 Bcf/day (39%) of GOM production remained shut in.

- While the prices of natural gas and oil are linked more closely today than at this same time last year, they remain partially delinked. If fully linked, the price of natural gas today would be about $17-$18 per MMBtu. The current natural gas price is less than half this.

- While not at record levels, as was the case last year, gas storage injections and inventory levels are high by historic standards. Natural gas in storage was 3,277 Bcf as of October 10, which is about 3% above the 5-year average, following an implied net injection of 79 Bcf.

- The futures markets, including speculators and hedge funds traders, have not sought a sustained increase in natural gas prices; futures prices across the country have consistently and generally declined since July, with particularly sharp declines in the West (e.g., Rockies).

- Amid signs of a softening economy, the spot price for natural gas at the Henry Hub remains relatively strong (just under $7/MMBtu), especially when compared to the recent precipitous decline in crude oil prices (about $75-$78/barrel).

Of course, other factors could potentially destabilize US natural gas supply, demand, and/or price. Despite a current steady balance in supplies, a decrease in unconventional production, without offsetting increases in LNG and/or Canadian imports into the US, could once again unbalance the US supply sector. 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. Also, Russia is seeking control of natural gas delivery utilities in Europe, and perhaps the US. Any or all of this combination could upset world supplies/prices, which could easily affect US supply and/or prices. 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 and a reduction in supplies. Fourth, the continued over-reliance on gas-fired electric generation must eventually increase the price of natural gas across the US. Fifth, any failure in the expected level or growth in the level of domestic natural gas production, either conventional or unconventional, could lead to an increase in price. Sixth, despite the fact that Canadian imports to the US are currently increasing, a decision by Canada to use more of its vast gas supplies for domestic development or to export more as LNG would certainly affect US price. Seventh, as noted in recent testimony before Congress, financial commodities traders dominate the US natural gas market in terms of money invested. It's difficult to say what and how much impact this fact will have on natural gas prices over the remainder of 2008 and into 2009. The Federal Energy Regulatory Commission's (FERC) and the Commodity Futures Trading Commission's (CFTC) "market manipulation" cases on oil and natural gas markets continue. Finally, and certainly not to be minimized, the current US financial crisis has already had some negative impacts on natural gas production, in terms of limitations on available credit and reductions in the overall market value of natural gas exploration and production companies. At the time of this writing, whether these negative impacts will continue or expand, or possibly decline, cannot reasonably be projected with any substantial degree of accuracy.

The US Department of Energy's (DOE) Energy Information Administration (EIA) weekly natural gas update shows the history of natural gas prices on NYMEX and physically at the Henry Hub, as well as the price of West Texas Intermediate (WTI) crude oil. Figures 1 and 2 are snapshots from this update for the period November 2007 to September 2008. As already noted, prices in both spot and futures markets have increased steadily since November 2007, reaching a peak in June and July. Figure 1 at the top of the next page demonstrates clearly that oil and natural gas prices are only partially linked. In Figure 2 (see bottom of next page), estimated prices for the Pacific Northwest (PNW) winter and PGA year futures strips are also depicted. As this figure demonstrates, PNW prices have followed closely the national pattern over the last year.

Figure 1: Natural Gas and WTI Prices, Nov 2007 – Oct 2008

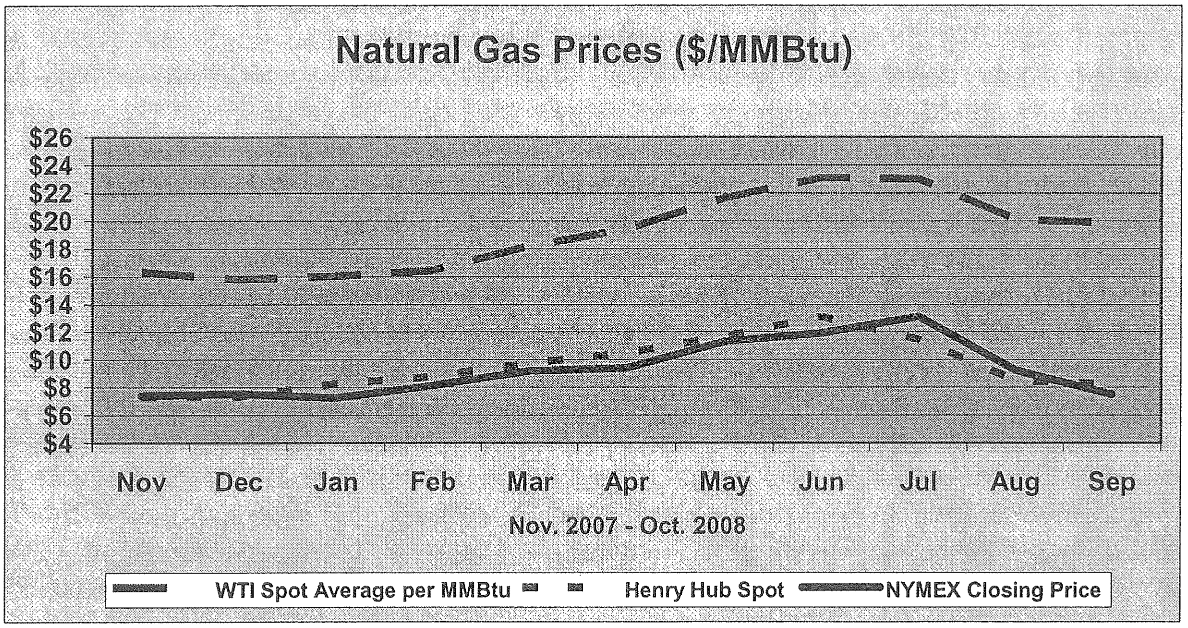
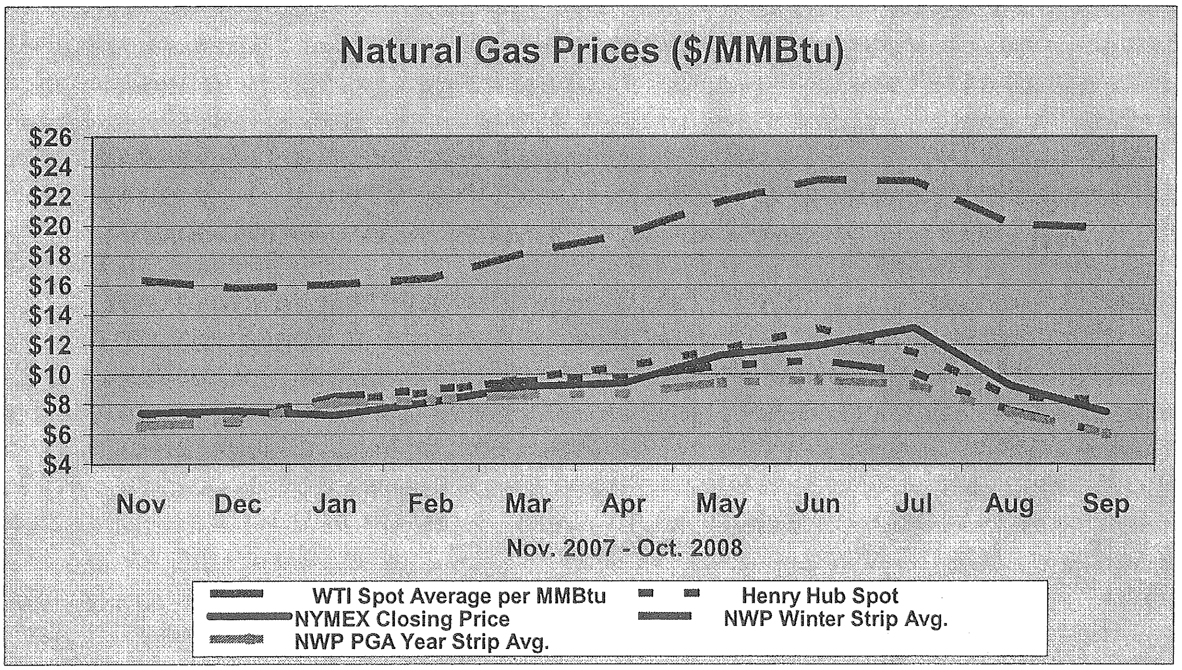


Figure 2: Natural Gas (National and PNW) and WTI Prices, Nov 2007 – Oct 2008



The EIA forecast of the natural gas price at the Henry Hub has fluctuated widely since January. The 12-month forecast began the year at just over $6.00, then moved to just over $8.00 in March, before reaching its peak of $12.01 in June. By August the 12-month forecast had fallen to $9.25 and in September the EIA's forecast for the next twelve months at the Henry Hub was just over $8.60. In October, the 12-month forecast from the EIA had declined to $8.40. Actual prices for spot gas at the Henry Hub began the year just under $8.00, jumped to nearly $13.00 by June, and currently stand between $6.50 and $7.00 depending on the day. These forecasts and actual prices translate to average natural gas prices, for the hubs from which Oregon LDCs purchase, of about $8.00/MMBtu for the PGA year and about $7.30/MMBtu for the winter season. Over this same period, NYMEX 12-month strips for the PGA year averaged about $9.50 while winter strips averaged about $10.00. PNW winter strips over the last year averaged $8.60, while strips for the PGA year average $8.00. Of course, all Oregon LDCs "lock-in" the price of a portion of their natural gas supply portfolio well in advance of the winter heating season for 2008-2009, including multi-year fixed price financial contracts, and place natural gas into storage during the off-peak season (spring and summer) 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 and price forecasts or simple averages of spot and futures prices over the twelve months from November 2007 through October 2008.

It appears the natural gas market has finally reached the price tipping point. From this time forward for the foreseeable future, prices at the Henry Hub will likely fall between $8.00 and $10.00 while PNW physical prices will likely fall in the range of $7.00 to $9.00. Futures prices are likely to be higher than these physical prices for both the nation and the PNW.

Natural Gas Purchasing Strategies

Staff continues to emphasize that "portfolio purchasing" 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 purchasing approach requires 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. The greater the risks of price change or supply availability, the greater the need to follow the diversity requirements of portfolio theory.

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 four years and were included in the last three PGA Staff Reports.

1. In specific practice, portfolio purchasing means the LDC must 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.

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. Some of, but not all, the LDCs also made this mistake in 2006 and 2007. We discuss Cascade's current hedging strategy in the following section, and Avista's and NW Natural's strategies in their respective Staff Reports.

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 on 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.

Cascade's Natural Gas Purchasing Strategies

In 2006, at the time of its PGA filing, Cascade had financially fixed the price for about 68% of its annual sales volumes. As Staff indicated at that time, this level of financial fixed-price hedging is more appropriate for Cascade than the level the Company had completed at the time of the filing of its 2005 PGA. The Company also expected to provide from storage about 6% of the volumes its customers required. That picture changed somewhat in 2007, with about 81% of firm natural gas deliveries fixed in price through financial hedging and another 4% drawn from storage (physically fixed price or physical hedging). Cascade's portfolio for the current PGA filing is shown in Table 3 below.

Table 3: Cascade Gas Supply Portfolio

Resource	Percentage in Portfolio
Pipeline deliveries of natural gas	90.16%
Citygate deliveries of natural gas	6.03%
Storage deliveries of natural gas	3.81%
Percentage of firm natural gas deliveries fixed via financial hedges	69%

Cascade may financially hedge additional volumes subsequent to its PGA filing. However, due to already completed hedges for 2008 and the small number of volumes remaining open for financial hedging currently, Cascade's additional financial hedging cannot involve large amounts of volumes. Staff recommended last year that Cascade not hedge more than the 81% of volumes hedged at the time of its PGA filing. That recommendation is made for Cascade's 2008 PGA as well.

Staff noted in last year's PGA that Cascade was focusing too much of its hedging activity during the three-month period June-August 2007. Staff recommended that Cascade spread its hedging activity across more of the PGA year. In 2008, Cascade hedged during May, June, July, August, September, and October. But about 80% of hedges were entered into during the three months June, July and August. In most years, the June through August period is an opportune time to complete financial hedging as it is an off-winter peak period and gas prices are generally at or near their annual low point. During 2008, this was not the case as already noted above. The fact that gas prices for the PNW during this period were at or above $10.00 makes the over-concentration of hedging in this period even more of a problem. Perhaps Cascade took this course of action because it was concerned that prices later in the year might be even higher than those in June, July, and August. This was not the case this year.

Cascade's situation with respect to financial hedging is complicated by additional factors, which to some extent mitigate but do not fully resolve the above concerns. First, Cascade financially hedges one-third of its warmer than normal annual demand each year. This rolling three-year hedging process is not inappropriate for Cascade, but it does substantially reduce the volumes available for hedging for any particular PGA year. In addition, Cascade's small size in terms of system load does not fit well with the normal parameters of financial hedging. Hedging contracts are generally sold in 10,000 Dth per day contracts. Because of its load characteristics, Cascade usually purchases only a portion of a contract (e.g. 2,500/day, 3,000/day). Such contracts are often slightly more expensive on a per unit basis than the full 10,000/day contract. Also because of its load size, Cascade has divided the PGA year into only three hedging windows: spring, summer, and fall. In practice, this means 1-3 hedges are entered into during each of these periods. Even with these circumstances in place, however, Cascade must make every effort to actually spread its hedging activity over this 9-month period and not focus it in late spring and summer. If additional hedges are completed by Cascade during September, this also will help to mitigate this concern. Cascade does not entirely agree with Staff's position but agrees with Staff that this is a topic for further discussion in the upcoming Phase II of Docket UM 1286 and in quarterly meetings with Staff and other interested stakeholders.

Staff continues to believe that Cascade's circumstances (purchasing limitations and risks) justify a higher level of financial hedging, and even fixed-price financial hedging. Financially hedging (but not all in fixed-price hedges) up to about 90% of the volumes required for the PGA year is thus, in Staff's view, appropriate for Cascade. But these hedges must be completed in accordance with appropriate portfolio purchasing standards. Staff also expects that Cascade will not enter into additional financial hedges if market intelligence and reliable fundamentals forecasts indicate purchasing gas at index price in either the daily or monthly market is a lower cost option. Staff will continue to discuss these issues with Cascade during regular quarterly and other meetings (e.g., IRP meetings).

Staff re-emphasizes its storage recommendation from last year. Cascade needs to increase its efforts to obtain additional storage for its Oregon customers. In 2006, the Company's portfolio included storage volumes of just over 6%, but due to loss of storage under a recall agreement with Avista Utilities, the Company's portfolio in 2007 and 2008 includes only 4% storage. Serving about 6% of annual demand from storage would be appropriate for an LDC of the size and operating characteristics of Cascade. We recognize that there may be impediments to additional storage acquisition on behalf of Cascade's Oregon customers, but Staff will continue to work with Cascade to help improve its storage position.

Cascade's overall hedge price for 2008 is approximately $8.40/Dth. When prior hedges are included, the overall hedge price included in Cascade's 2008 PGA is about $8.20. The 2008 hedge price is within the range Staff calculated as reasonable for PNW futures pricing (see Table 4). Also, Cascade's 2008 hedging price is only slightly above that of NW Natural ($8.33/Dth) but noticeably lower than the Avista hedging price ($8.87/Dth).

Table 4: Staff's Hedging Price Range for 2008 PGAs[2]

High	Low
$8.60	$8.00

Cascade's Natural Gas Costs

During the period November 2007 to October 2008 when Cascade purchased gas for the period November 2008 through October 2009, the average cash (spot) price in the PNW was approximately $8.03/MMBtu. PNW spot prices increased steadily through this period, reaching near $10.50 in June. Spot price dropped in July and reached a low point just below $6.00 in September. The NYMEX PGA strip price over the period November 2007 to September 2008 averaged about $9.50/MMBtu for the PGA year and about $10.00/MMBtu for the winter period, with a similar price pattern to the Henry Hub physical prices. Over that same period, the average forward prices for the hubs at which the Oregon LDCs purchase were about $8.10/MMBtu for the PGA year and about $8.60/MMBtu for the winter period, also with a similar price pattern.

The commodity price and transportation demand charge Cascade proposes to pass through to its sales customers are shown in Table 5 (see top of next page), along with the range of prices for commodity Staff recommends as reasonable. Staff accepts the demand charge proposed by Cascade, as it is established via FERC tariff. Staff has only verified that the transportation charge proposed by Cascade is the actual charge approved by FERC and in place currently.

Cascade's proposed weighted average cost of gas (WACOG) is just above the bottom of Staff's range of WACOGs. The proposed commodity WACOG is a 6% percent increase over the company's current WACOG.

[2] This range is based on a weighted average made up of high and low prices for the winter and PGA year Pacific Northwest winter strips combined with the averages for these strips over the period November 2007 to September 2008.

Even in the context of the several concerns about Cascade's purchasing practices, particularly financial hedging identified in the previous section, the Company's gas costs are reasonable.

Table 5: Cascade Commodity and Demand Costs for 2008 PGA[3]

Charge ($/therm)	Cascade	Staff's Range
Commodity	$0.83429	$0.82500 - $0.87500
Commodity (revenue sensitized)	$0.85455	
Demand	$0.08958	$0.08958
Demand (revenue sensitized)	$0.09176	
Total	$0.92387	$0.91458 - $0.96458
Total (revenue sensitized)	$0.94631	

The Company's workpapers support the overall natural gas commodity and transportation cost related increase in revenues proposed by Cascade of $2,219,686.

Technical Adjustments - Deferred Accounts

Cascade's application proposes to make technical adjustments in amortizing credit and debit balances in its deferred accounts. This activity consists of the following components:

- Removal of net temporary credit increments currently in place, increasing revenues by $2,971,372.
- Addition of a new temporary increment of $280,923 to the Company's deferred accounts as detailed in Table 6 at the top of the next page. The Commission previously authorized all of the deferred amounts subject to amortization.

[3] The low value in Staff's range is a ±1 SD/0.5 SD weighted average of the median and average values for the PNW futures strips for the winter and PGA year over the period November 2007 to September 2008 in combination with the average of two fundamentals forecasts. The high value in Staff's range is a ±1 SD/0.5 SD weighted average of the highest values for the PNW futures strips for the winter and PGA year over the period November 2007 to September 2008 in combination with the average of two fundamentals forecasts. Both values are rounded to the nearest cent.

Table 6: Cascade Temporary Revenue Increments for 2008 PGA

Temporary Debit (Credit) Revenues	Amount
Commodity and Demand costs	$2,001,874
UM 1283 Revenue Credit	($200,000)
Intervenor Funding	$75,456
Earnings Sharing	($248,426)
Conservation Alliance Plan	($1,347,981)
Total	$280,923

The net revenue effect of adding the new temporary increments and removing the current increments is an increase of $3,252,295 on an annual basis. Staff has reviewed the Company's technical adjustments and determined that the proposed amortizations are appropriate. The revised amortization increments are incorporated in the energy charge component of the Company's primary rate schedules.

Other Base Rate Adjustment

CAP Baseline Adjustment: Staff reviewed the Company's calculations that support the change in baseline rates associated with the decoupling mechanism. In this filing, the adjustment credits about $0.03 per therm to residential customers' rates and approximately $0.01 per therm to commercial customers' rates. The total decrease to revenues is $150,273.

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 the 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. Cascade's mechanism includes a 33% sharing level, so amortization of deferred gas costs in this PGA filing is exempt from an earnings review.

ORS 757.259 (6) and (7) state 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 preceding calendar year, unless the Commission finds that allowing a higher amortization rate is reasonable under the circumstances. Cascade's proposed net amortization under this statute for 2008 is $1,553,448, or approximately 1.4% of the previous year's gross revenues, and should be implemented as proposed.

UM 1389

In this filing, the Company requests reauthorization of deferrals for (1) all of the gas cost differences associated with purchases of gas supplies for system requirements that differ from gas costs embedded in rates, consistent with the procedures outlined in its Schedule 177; and (2) changes in margin due to conservation and variances from normal weather under the CAP mechanism, effective for the twelve months beginning November 1, 2008. 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 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.

PROPOSED COMMISSION MOTION:

Cascade Natural Gas Corporation's request for: (1) amortization of deferred accounts, base gas cost changes, and rate changes as requested in Docket No. UG 185 be approved; (2) the application for LSN be granted, and the associated tariff sheets in Advice Nos. O08-08-02 and O08-08-02-A be allowed to go into effect with service on or after November 1, 2008; and, (3) the request for reauthorization to use deferred accounting pursuant to its Schedule 177 and Rule 19, for one year beginning November 1, 2008, be approved.

Attachments

Cascade 2008 PGA

Attachment A

Cascade Natural Gas
Rates & Regulatory Affairs
2008-2009 PGA Filing - Oregon: October refiling
PGA Effects on Revenue

Purchased Gas Cost Adjustment (PGA)	**Amount**
Commodity Cost Change	$3,673,759
Demand Capacity Cost Change	(1,454,073)
Total Gas Cost Change	2,219,686
Temporary Increments	
Amortization of Commodity and Demand Cost Differences	2,001,874
Amortization of Intervenor Funding - CUB & NWIGU	75,456
Amortization of 2008 Earnings Sharing	(248,426)
Amortization of Decoupling (Residential & Commercial)	(1,347,981)
Amortization of UM 1283 Revenue Credits	(200,000)
Total Proposed Temporary Increments	280,923
Removal of Current Temporary Increments	2,971,372
Total Net Temporary Rate Adjustment	3,252,295
Permanent Rate Adjustments	
CAP Baseline Adjustment	(150,273)
Total Net Base Rate Adjustment	(150,273)
TOTAL OF ALL COMPONENTS OF ALL RATE CHANGES	**$5,321,708**

Attachment B

Comparison of Proposed Rate and Bill Increases for Oregon Local Distribution Companies by Class of Service

(November 2008 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*	$1.40692	$1.35380	-0.05312	-3.8%	100	$6.00	$146.19	$141.38	-$4.81	-3.3%	53	$6.00	$80.07	$77.75	-$2.32	-2.9%
Cascade	101	$1.20884	$1.27656	0.06772	5.6%	113	$3.00	$139.60	$147.25	$7.65	5.5%	59	$3.00	$74.32	$78.32	$4.00	5.4%
NW Natural	2	$1.22449	$1.41502	0.19053	15.6%	109	$6.00	$139.47	$160.24	$20.77	14.9%	56	$6.00	$74.57	$85.24	$10.67	14.3%
Commercial																	
Avista	420*	$1.33604	$1.27304	-0.06300	-4.7%												
Cascade	104	$1.10819	$1.17591	0.06772	6.1%												
NW Natural	3	$1.12149	$1.30440	0.18291	16.3%												
Industrial																	
Avista	424	$1.22216	$1.18830	-0.03386	-2.8%												
Cascade	105	$1.04579	$1.15085	0.10506	10.0%												
NW Natural	31ISF	$0.81672	$0.99780	0.18108	22.2%												
Interruptible																	
Avista	440	$0.92531	$0.89385	-0.03146	-3.4%												
Cascade	170	$0.99242	$1.09689	0.10447	10.5%												
NW Natural	32ISI	$0.74241	$0.93976	0.19735	26.6%												

* Rate Schedules 410 and 420 include the Margin Reduction Surcharge (in Rate Schedule 496) allowed under the approved Stipulation in Order No. 03-570.
Avista's proposed billing rates also include the effects of rate changes previously approved in Order No. 08-185, Docket UG 181.

Attachment C