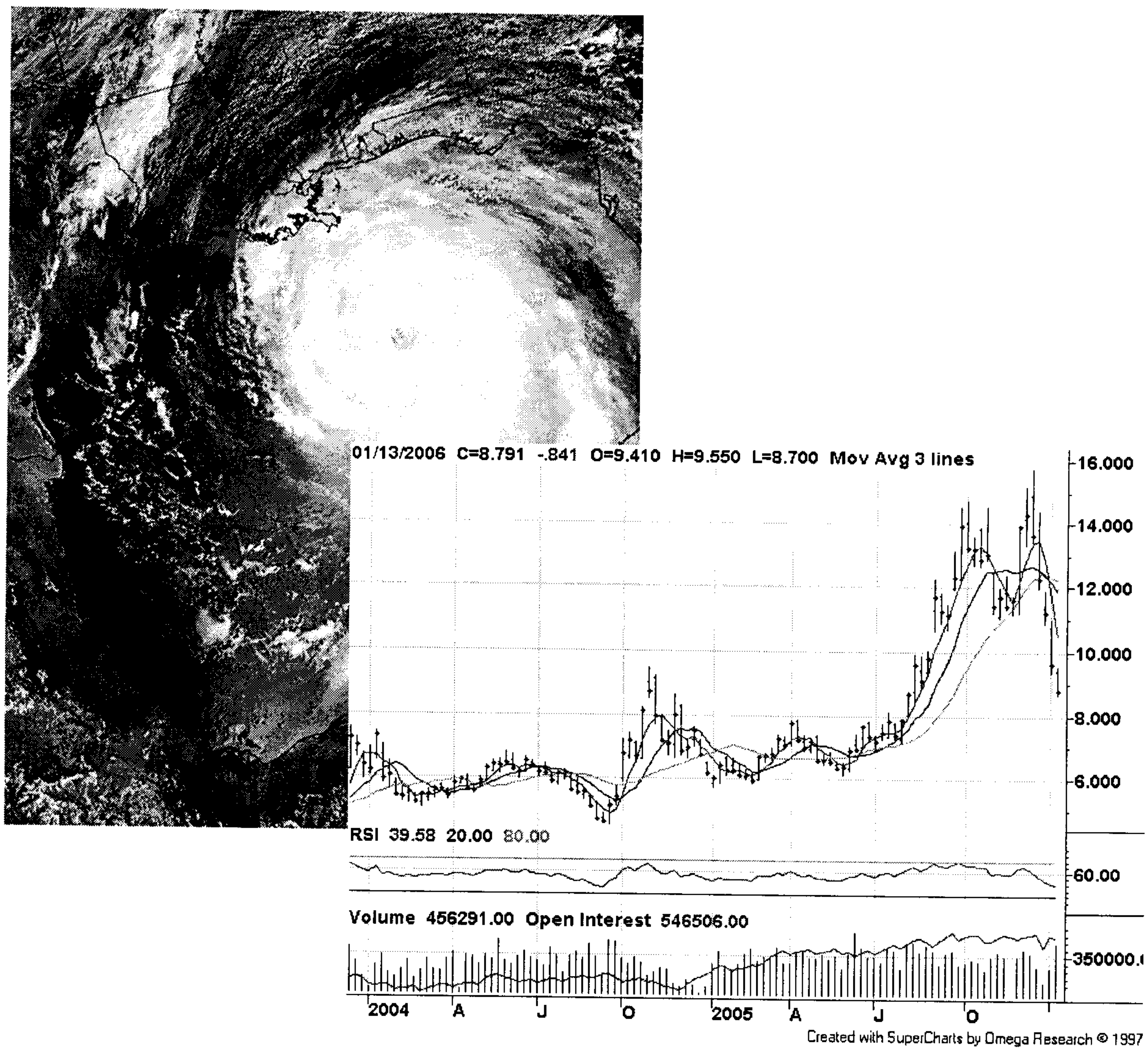
Joint Report on Natural Gas Market Conditions, PGA Rates, Customer Bills & Hedging Efforts of Missouri's Natural Gas Local Distribution Companies



In the Matter of an Investigation into the Status of	**)**	
Missouri's Natural Gas Local Distribution Companies'	**)**	**Case No. GW-2006-0110**
Compliance with Commission Rule 4 CSR 240-40.018	**)**	

Issued February 24, 2006

Table of Contents

I. Executive Summary & Joint Recommendations

There appears to be three general categories with respect to hedging performance by gas utilities this winter: those that, on or before November 1st, hedged a very high percentage of expected heating season needs, 80% or more (AmerenUE and Aquila); those that hedged in the 50% to 60% range (Atmos, Laclede and MGE) and those that did relatively little or no hedging by that date (Southern Missouri Gas[1], MGU and Fidelity[2]). Thus, over 95% of the natural gas customers in Missouri served by a MOPSC regulated utility are served by a utility that hedged 50% or more of its normal winter supplies against exposure to market prices this winter. However, these numbers do not reflect the significant disparities in hedging percentages, and the mechanisms used to hedge gas supplies revealed in this investigation.

A common topic in the parties' discussions leading up to this report was the "Natural Gas Price Volatility Mitigation" rule's language and intent. The purpose statement accompanying this rule states:

> *This rule represents a statement of commission policy that natural gas local distribution companies should undertake diversified natural gas purchasing activities as part of a prudent effort to mitigate upward natural gas price volatility and secure adequate natural gas supplies for their customers.*

A central question is what is an appropriate hedging strategy? The answer depends on your view of hedging's objectives, benefits, costs and risks. Hedging strategies that obtain price certainty in lieu of price variability may not result in the lowest costs. If a utility sets an objective to achieve the lowest delivered cost to its customers; and if market prices stay at, or increase from, current levels; then the lower the percentage of market price exposure the better. If market prices drop significantly, the opposite will be true. If a utility has targeted its hedging strategy at limiting exposure to market price spikes, the appropriate level of hedging for that utility will depend on its perception of forecasted market price trends and the benefits, costs and risks of relative hedging mechanisms.

---

[1] On January 3, 2006, Southern Missouri Gas did enter into several fixed price contracts which hedged approximately 65% of its expected natural gas requirements for the remainder of this winter.
[2] On November 1, 2005, and January 17 and 18, 2006, Fidelity Natural Gas, Inc. entered into several fixed price contracts which hedged approximately 18% of its expected natural gas for the remainder of this winter.

At the end of this section, this working group has listed its recommendations for steps the Missouri Public Service Commission (MOPSC) should take to provide greater guidance to LDCs on hedging objectives and strategies, and other steps the MOPSC should take to mitigate the effects of high natural gas prices.

This report identifies all utility PGA rate changes, estimated customer bills impacts and hedging efforts for each of Missouri's natural gas Local Distribution Companies (LDC) known as of the date of this report. Some utilities had aggressive hedging strategies in place for this winter; some utilities had taken a somewhat less aggressive, although substantial, approach; and some utilities chose less aggressive approaches. Even substantial approaches may have exposed customers to significant price volatility. For example, an LDC that hedged 50% of its winter supply still had 50% of the normal winter supply unhedged.

The individuals in this working group also provided their perspectives regarding the national issues that are contributing to high natural gas prices. Some of these opinions mirror those expressed by organizations like the National Petroleum Council and the American Gas Association.

This report also reiterates some of the natural gas price concerns and recommendations of some past task forces and working groups.

The stakeholders that developed this report appreciate the MOPSC's attention to this matter and believe that implementation of the following joint recommendations will improve the hedging practices of Missouri's LDCs and help to mitigate the impact of changing and higher natural gas prices on consumers in the future.

Joint Recommendations

Recommendation No. 1: The MOPSC should open a case for the purpose of amending MOPSC Rule 4 CSR 240-40.018, the "Natural Gas Price Volatility Mitigation" rule. Although it is premature to set out detailed amendments to the hedging rule, goals of this rulemaking may include:

- Clarification that the provisions of this rule are mandatory unless a waiver or variance has been granted.
- The establishment of a minimum future timeframe over which planned gas hedging (financial instruments as well as physical supplies) must occur (e.g. 3 year minimum period for physical purchases and hedging and 5 year minimum period for capacity planning).
- The establishment of minimum boundaries for hedging programs unless good cause is shown for any deviations from these minimums (e.g. no less than 65% of the upcoming normal winter's supplies shall be hedged against market exposure by no later than October 1st each year).
- The establishment of a formal process for LDCs to provide the MOPSC and other interested parties with planned natural gas hedging (financial instruments as well as physical supplies) positions each spring and updates for the coming winter each fall. This process would need to include provisions for updates to the MOPSC and other interested parties if any substantial changes to plans are made.
- The establishment of a process for receiving comments on hedging plans in a timely manner so as to not delay the utility's implementation of its hedging plan (e.g. comments in writing within 30 days after hedging plan is filed).
- The establishment of a formal process for integration of information on hedging positions into the PGA/ACA process. This process could result in more up-front information on hedging positions, fewer surprises when PGA change filings are made, and a reduction in the amount of discovery related to hedging positions and outcomes in the ACA process.
- Recognition of appropriate hedging mechanisms that mitigate upward price volatility and mechanisms that may have other potential benefits but are not recognized as hedging mechanisms. This recognition will need to leave room for consideration of future hedging tools that may be developed and still retain flexibility for the LDCs to respond to changing market conditions. The

responsibility to respond to changing market conditions should continue to be with the LDC.

- Recognition of appropriate different standards or exceptions for small LDCs and for LDCs with small systems with separate PGAs.
- Changes to the current PGA/ACA process.
- Planned hedging (financial instruments as well as physical supplies) parameters that would apply during summer periods.

While not specific to this rulemaking effort, collaborative rulemaking meetings may provide for development of a "best practices" document. The parties expressed interest in working on development of such a document in conjunction with efforts to change the current "Volatility Mitigation Rule" and the PGA/ACA process.

Rationale for Recommendation: Under the current rule, some Missouri gas utilities have responded to price volatility by aggressively hedging and some have responded by doing very little. This situation may indicate that the current rule does not provide sufficient guidance and/or opportunity to assess penalties. It may also indicate that some utilities have not viewed this rule with sufficient weight in the timing and execution of their gas purchasing programs. It appears that the MOPSC wants more information at an earlier time concerning hedging activities and projected PGA estimates. It may be possible to address all of these concerns during the ACA process while mitigating some LDC concerns about sufficient guidance on major planning decisions and providing more certainty regarding these decisions.

Recommendation No. 2: The participants recommend possible implementation of these energy efficiency and consumer education recommendations from the task force reports in Case Nos. GW-2001-398 and GW-2004-0452:

- Develop Education Programs on Efficient Energy usage (flyers, videos, web portals, toll free phone number, etc…). DNR has a significant amount of information on their current website related to energy efficiency and weatherization and has indicated that they may be able to revise this site to provide more of the educational information discussed by the task force. The task force does, however, believe that a site devoted strictly to energy cost issues, long-term energy affordability, where to find assistance, and how to improve the energy efficiency of a home with a highly searchable title would be somewhat more beneficial. As part of this educational effort, methods to aid in earlier identification of developing arrearage problems, and designing appropriate collection/assistance measures should be developed.

- Pursue an active role in regular Public Service Announcements to advise the public on energy price concerns, where to seek assistance, and how people who wish to make a contribution can do so.
- Pursue increased governmental funding for low-income energy assistance and weatherization programs.
- Develop a Utilicare check off box on Missouri income tax forms for donations.
- Develop an incentive for high efficiency appliances and other energy efficiency measures that are purchased, e.g., tax credit.
- Implement statewide energy efficiency standards for new building construction and major building rehabilitations.
- Incorporate rate designs that remove disincentives for utilities to pursue programs aimed at reducing usage and do not penalize customers for conservation.

II. Hedging Approaches, Benefits, Risks, Alternatives & Limitations

Hedging for natural gas LDCs can be defined as the management of a natural gas portfolio to mitigate adverse upward price volatility, i.e. the use of both physical positions and financial instruments to avoid a total reliance on spot market purchases or a market based index. This includes recognition that the goal of hedging is not to "beat the market" but rather to mitigate upward price volatility. Physical positions that LDCs can utilize include storage and fixed-price contracts. Financial instruments available in the market include, but are not limited to, futures contracts, option contracts, collars, swaps, and certain combinations of the above. These financial instruments can be purchased through a regulated exchange such as the New York Mercantile Exchange (NYMEX), or through the over-the-counter market (OTC), where one party may be a major financial institution.

Management of the natural gas portfolio also extends to the purchasing decisions of the LDC regarding these positions. Does the LDC make regular purchases of financial instruments throughout the year (dollar-cost averaging)? Does the LDC try to time its purchases of financial instruments to take advantage of perceived dips in the market? Does the LDC focus only on the approaching winter heating season (short-term outlook)? Does the LDC blend in purchases for future winter heating seasons (long-term outlook)? Does the LDC simply ride the market or ride the market price with a locked-in basis differential? Finally, are there alternatives to these approaches? This section of this report addresses the various physical and financial instruments available to Missouri LDCs and the benefits and risks of each strategy.

PHYSICAL POSITIONS

One type of a physical position is storage. Natural gas storage is where LDCs (and others) actually purchase natural gas in the non-winter season (generally April – October) and put the natural gas in a storage facility. These facilities are located near pipelines and may be depleted natural gas reservoirs or other geological structures that permit the injection and withdrawal of natural gas.

There are two main reasons why LDCs purchase and place natural gas in storage. In order to address the demand put on the system in the winter to meet the residential heating load, LDCs must use natural gas from storage because production facilities cannot produce enough natural gas to meet the demand at that time. This operational requirement is the primary purpose of storage.

In addition, natural gas purchased for storage serves as a physical hedge. When LDCs purchase and inject natural gas into storage for later sale in the heating season (November – March), the LDC has fixed the price of natural gas it will charge its customers for those volumes. For example, if an LDC fills its storage with natural gas at an average price of $5 per million British Thermal Units (MMBtu), it knows in advance of the heating season that one component of its needed supply will be $5/MMBtu. The MMBtu is a common market volume for natural gas pricing and is roughly equivalent to the heat output of about 1,000 cubic feet of natural gas. PGA rates are sometimes expressed in dollars per Ccf where a Ccf is equal to 100 cubic feet of natural gas. Flowing gas supplies during the heating season may be higher or lower than $5/MMBtu but the price associated with the stored natural gas will be $5/MMBtu. Thus, storing natural gas helps to fix the price to be charged consumers and helps the LDC to have enough natural gas to meet demand. Storage also gives the LDCs flexibility in handling its supply portfolio. However, not all of Missouri's LDCs have storage available to use as part of their natural gas supply portfolio.

Storage has some costs; however, these costs generally pale in comparison to the benefits of storage. Losses occur during the injection and withdrawal process, or during the time that the natural gas is in storage. In addition, there are charges by storage facility operators and financial costs of carrying the natural gas inventory until it is sold in the winter. Also, some storage contracts have rigid injection and withdrawal timelines and inventory requirements. For LDCs that have storage resources that are used for operational and/or hedging purposes, the LDC must have a reasonable plan to fill storage prior to the winter heating season.

Fixed-price contracts are another type of physical position. These consist of an LDC contracting directly with its supplier to purchase natural gas for future delivery at a set price. For example, in July 2005, an LDC could reach an agreement with its supplier to take a fixed amount of natural gas in January of 2006 for a set price of $7/MMBtu. Depending upon the size of the LDC, this could be a portion of its supply portfolio, or the entire supply portfolio. This type of instrument is very similar to a futures contract that is traded on the financial markets.

Fixed-price contracts provide complete price certainty for the agreed to volumes thus eliminating exposure to market price increases. Any form of index pricing is subject to price uncertainty until the associated index is published and only fixes the given price for the contracted term (e.g. for one month if the contract has a monthly price index provision). These types of mechanisms should generally be available to all LDCs in Missouri, regardless of size. The Staff and Public Counsel emphasize here their position that First of the Month (FOM) index pricing is not a hedge, although other parties have contended it is since it fixes the price of gas for a fixed period of time.

The use of fixed-price contracts include the risk of being "above the market" (*e.g.,* the first of the month index price or the daily price prevailing during the delivery month) and the potential for non-performance. Once the contract is signed, the price for the fixed volumes is set. Thus, if the price of natural gas drops before the gas is delivered by the producer, the LDC's contract price will be above the market price. Also, there is the potential that the supplier may not be able to fulfill its contract obligations to deliver.

FINANCIAL INSTRUMENTS

The first type of financial instrument is the futures contract. Futures contracts are generally purchased through the NYMEX, or from an institution such as a major financial institution. The futures contract is very similar to the fixed-price contract, but actual delivery of natural gas seldom occurs. The futures contract purchased through the NYMEX or a major financial institution has the advantage over a fixed-price contract in that the credit risk of non-performance has been eliminated (NYMEX futures) or greatly diminished (financial institution). Also, futures contracts are much more liquid than fixed-price contracts because of the standard contract terms and the market discipline imposed on buyers and sellers in them. This gives the futures contract greater flexibility. Also, futures contracts are relatively cheap compared to other financial instruments. A futures or forward contract works the same as a fixed-price contract, with a small transaction fee added.

One drawback to the use of futures is the potential to lock in a price for natural gas supply above the spot market price (*e.g.,* the first of the month index price or daily price prevailing during the month of consumption). Second, when the futures contract price falls from its initial purchase price, the purchaser is subject to margin calls to cover the loss in value of the contract. Another limit on the use of futures contracts is that smaller LDCs, with their smaller loads, may be precluded from purchasing futures contracts, which have standard volumes of 10,000 MMBtu per contract.

A second type of financial instrument available to use in a LDCs natural gas supply portfolio is options. Call options give the purchaser the right, but not the obligation, to purchase a futures contract at a set (or strike) price in a future period. A put option gives the purchaser the right, but not the obligation, to sell a futures contract at a set (or strike) price in a future period. In order to purchase an option, the buyer pays a premium to the seller. The option premium varies depending on the volatility in the market, the underlying price of the futures contract, and the time until the contract's expiration.

Buying call options works as a cap or ceiling on the price to be paid for natural gas. In other words, when a call option is purchased, the buyer knows the price they will pay for the specified volumes will not be greater than the strike price, plus the premium. An advantage of using call options is that while it limits the upside price risk, the purchaser can take advantage of downward movements in market price simply by allowing their call option to expire. In this way, the LDC is only out the amount of the premium. For example, assume an LDC pays a $.50 premium for call option with a strike price of $6/MMBtu. If the actual price of natural gas increases to $8/MMBtu, the LDC would exercise its option, and the option seller would pay $2/MMBtu to the LDC. The effective price the LDC will pay for natural gas is $6.50/MMBtu (the $6 strike price plus the $0.50 premium). On the other hand, if the price of natural gas falls to $4/MMBtu, the LDC will purchase the volumes at $4 and will allow its call option to expire without execution. The effective price paid for natural gas in this example is $4.50/MMBtu ($4 plus the $0.50 premium paid for the option).

A negative aspect of hedging with call options is that the premiums can become prohibitively expensive. Because the price of the option is based, in part, on the volatility and the underlying price of the commodity, as the futures price increases, so does the premium associated with an option. For example, five to ten years ago when the price of natural gas traded between $1.50 and $3.50/MMBtu, an option with a $4 strike price would cost about $0.10/MMBtu. As of February 7, 2006, with prices at nearly $8/MMBtu for a March 2006 contract, an option with a strike price around $15/MMBtu for January of 2007 is currently trading at a premium of $1.17/MMBtu.

A third type of financial instrument utilized by LDCs is a swap. A swap is defined as an agreement between two parties to exchange a series of cash flows generated by an underlying asset. In a swap, one party (financial institution) agrees to pay the other (LDC) a fixed price for natural gas, for instance $8/MMBtu, for the agreed upon volumes. The financial institution will either pay or collect the difference between the contract price and a given First-of-Month (FOM) price index (usually where the LDC actually purchases its natural gas supplies). When used by a LDC a swap works like a futures contract, and is generally executed between the LDC and a financial institution, such as a major bank.

Financial instruments can be used in combination to balance price risk or reduce the overall cost of hedging. One combination of financial instruments used by LDCs is a collar. A collar pairs a call option with a put option to set a ceiling and floor for the price of natural gas. A put option works as a floor on the price to be paid for natural gas whereas a call option places a ceiling on the price. For example, an LDC buys a call option with a strike price of $10/MMBtu for a premium of $0.50/MMBtu, and at the same time sells a put option with a strike price of $7/MMBtu for a premium of $0.20/MMBtu. This means that the LDC has basically "collared" the price of natural gas between $7 and $10/MMBtu, and the premium received for the put option offsets part of the premium paid for the call option. The call option sets the ceiling price and the put option sets the floor price for the covered volumes of gas. If the cost of the call option and the price of the put option are equal, the arrangement is known as a costless collar.

However, because the collar is established using options, as the price of the underlying futures contract increases and becomes more volatile, the cost of a collar also increases. As a practical matter, high prices greatly reduce the difference between the floor and ceiling prices or price the collar above the value of the current futures price. Thus, while periods of high natural gas prices may result in some natural gas utilities relying more extensively on collars, such prices can also limit the protection that such collars afford.

HEDGING STRATEGIES

This section will discuss how an LDC may implement its hedging program.

Dollar Cost Averaging, Timing the Market and the Portfolio Approach

Once the determination has been made to hedge against upward price volatility and what instruments to use, the LDC must decide when to purchase those instruments. Another important decision is how much to hedge and how much of anticipated requirements to allow to follow the market. One approach to buying hedges is dollar cost averaging. Dollar cost averaging is making regular purchases at predetermined time intervals, with limited regard to market conditions. For example, in the early spring an LDC preparing for the upcoming heating season decides to dollar cost average its purchase of futures contracts by making in the months of May, June, July, August, and September five equal purchases. Thus if the LDC needs 100 contracts to hedge its load, it would purchase 20 contracts in each month.

This approach eliminates the guess work of when to make purchases, an approach favored by those who believe that no one can really predict the market. Under the dollar cost averaging approach, purchases are not made to outguess the market, but to recognize that even though prices may seem high today, they may be even higher in the future. Another aspect of dollar cost averaging is that it ensures that the LDC meets its hedging goals in a timely fashion. This avoids the temptation to postpone taking positions on the chance that prices will decline in the future.

A risk of dollar cost averaging is that purchases may be made at inopportune times. If the plan requires 20% of hedges must be made in August and a major hurricane hits the natural gas supply and production area, positions may be set as the price spikes in the short-term due to this event. The natural gas market has always been volatile, and short-term events can cause the price to rise rapidly for a short period time, only to fall back. If an LDC is locked into a situation where it has to purchase to meet a dollar cost averaging schedule, it may be purchasing during short-term price peaks. This particular concern is one reason to use dollar cost averaging approaches in multi-year programs to avoid obligations that can result in significant purchases during periods of extreme market prices.

Another approach available to LDCs is to make hedging purchases when it perceives prices as being advantageous, meaning that the LDC tries to time, or beat the market. The LDC, based on a variety of factors such as history and current market conditions, tries to time its hedging purchases to take advantage of low prices and avoid short-lived price spikes. The advantage to this approach is that it gives the LDC flexibility in its purchasing. The LDC is not locked into making a 20% purchase during a heat wave in July when natural gas prices are soaring due to the demand for electric generation. However, trying to beat the market can backfire. The higher prices associated with a hot July or August could linger, leaving the LDC with no choice but to hedge a significant portion of its expected load at high prices in September and October, or even risk riding the market through the winter.

A modification of the dollar cost averaging and market timing methods is a portfolio management approach. Like the programmed dollar cost averaging method, there is a disciplined plan to purchasing supplies. Rather than rely upon strict average monthly purchases, goals for long-term purchases are set throughout the multi-year purchasing cycle. This allows for flexibility to react to markets by purchasing more or less for the portfolio in some months than in others, and to allow hedging purchases for three or more years in the future. The portfolio couples financial hedges with physical supplies actually purchased.

Every six months the future period is advanced and new goals for the portfolio must be set. This approach provides a disciplined method to layer in purchases over a long time period, but allows the utility some flexibility to react to some market conditions throughout the course of the year.

For example, the hurricanes in 2005 have had a significant impact on NYMEX futures prices in 2007 and beyond, even though actual production in 2007 will not likely be impacted by those hurricanes. The portfolio management approach allows the utility to wait several months, until the volatility due to the current crisis hype has subsided, on making purchases for 2007 and beyond.

In addition, the portfolio management approach employs a variety of pricing mechanisms. Physical purchases may be priced at fixed prices from the supplier, hedged by NYMEX futures, financial swaps or a combination of put and call options. The portfolio management approach therefore provides price diversity through layering in a variety of contracts throughout the course of the year.

Short-term vs. Long-term

Another factor is the LDC's hedging horizon. Currently, most LDCs only hedge for the upcoming winter heating season, a short-term outlook. However, some LDCs have expanded their hedging horizon and look at more than a year into the future, a long-term outlook.

During the course of any one-to-five year period, the price of natural gas may be rising, falling, or both; that is high one year, low the next. A long-term outlook is beneficial if the LDC expects gas prices to rise over any given period of time. It allows the LDC to lock in prices at lower levels now. However, if prices fall from current levels, the LDC will have locked in prices that tend to be higher than current market conditions. A short-term outlook has the advantage of focusing only on the year at hand. The LDC will have a better idea of its needs and may be able to take advantage of lower prices if the market is declining. However, if the market in the short-term is on the upswing, the LDC will have missed an opportunity to establish lower prices by purchasing hedges in previous low price markets. Another item to consider in assessing the time horizon over which hedges are to be placed is the LDC's increased exposure to credit risk which occurs as the time horizon is extended. LDCs should formulate their long-term market expectations and factor them into purchasing plans.

Within this debate over whether to keep a short-term outlook or a long-term outlook is the decision to dollar cost average or not. A hedging plan could incorporate dollar cost averaging over a period of years. For example, if a LDC had a five-year outlook, it could decide to lock in 20% of its prices each year. Thus for 2010, the LDC would lock in 20% in 2006, 20% in 2007, 20% in 2008, etc. Or, it could try to time the market anticipating this may be an era of low prices and taking hedge positioning now for several years in the future; conversely if it is a period of high prices it may defer taking hedge positions.

Alternatives

The risk of adverse price movement is always a possibility in the market. The main alternative to actively hedging against that risk is not hedging. Not hedging exposes customers to the volatility of the market. If the price falls, the LDC's customers enjoy the lower prices; if the price increases, the LDC's customers face higher bills. Predictably, prices generally fall when the winter weather is warmer-than-normal, and therefore, the customer's usage is lower. Thus, the customer has lower usage and lower prices. On the other hand, prices generally increase when the winter weather is colder-than-normal. When this happens, the customer's usage is higher. Thus, the customer's bill impact is compounded by both high prices and higher usage. Also, while there is a limit to how far prices can fall, there is almost no limit to how high prices can rise. The market has not seen prices below $1.50/MMBtu in a decade and has not seen prices below $2/MMBtu in about five years.

Budget billing is one mechanism available to customers who wish to have more stable bills. While this is not a form of utility hedging it is an option customers who value bill stability should consider.

Locking In Basis Differentials

While Staff and the Office of the Public Counsel do not generally view basis differential locks, as a stand alone tool, as an effective hedging mechanism, the following discussion is included in this report since several natural gas LDCs entered into these types of agreements. Basis differential is the price difference between two delivery points. Generally speaking, basis is the difference between the Henry Hub in Louisiana and the First-of-Month (FOM) index used by the LDC to price its actual natural gas supplies. Henry Hub is the point used to price the NYMEX futures contract and is considered a primary pricing point. Most, if not all, LDCs in Missouri purchase their natural gas from other basins, with pricing provisions based on prices for gas delivered into the interstate pipeline that delivers the natural gas from the supply basin to the LDC. Examples would be FOM indices for Panhandle Eastern Pipe Line Company (PEPL), Southern Star Central (SSC), or Natural Gas Pipeline Company of America (NGPL). Because the prices at the Henry Hub and the PEPL basin are different, there is a basis differential. Generally, the Henry Hub price is the higher price; however, the index price and the Henry Hub usually move in tandem.

Even though the prices move in tandem, one of the prices may move more rapidly than the other. An LDC could hedge this changing basis differential through a basis swap. For instance, due to the hurricane damage in the gulf coast region this year, the differential between Henry Hub prices and Mid-Continent (Kansas – Oklahoma) prices has increased. Since this basis differential varies over time, a LDC could lock in a basis differential when it perceives the current differential to be greater than it will be when the actual natural gas needs to be purchased. For example, assume a historical basis differential is $0.50/MMBtu (meaning if the price at the Henry Hub is $7/MMBtu, the Mid-Continent index price is $6.50/MMBtu). Next, assume that the basis differential has grown to $0.75/MMBtu, and the LDC locks in this basis differential. If the price at the Henry Hub is $8/MMBtu when the LDC purchases its actual supplies, it will pay $7.25/MMBtu ($8 - $0.75(basis swap)). Since the historical basis was $0.50/MMBtu, the LDC may have saved $0.25/MMBtu. In effect, the basis swap locks in a fixed discount from the NYMEX price. This action does not protect against adverse price movements in the larger, underlying price of the gas. If the price at the Henry Hub increases to $20/MMBtu, the LDC's customers will pay $20 less the locked in basis.

Locking in a basis differential may be helpful to small LDCs that otherwise have limited tools available for mitigating high prices on their systems. By locking in basis differentials, the LDC may secure a larger discount off the index price and secure a lower overall price for its customers when the prices begin to decline. It also avoids the costly up-front fees and credit requirements of some other financial instruments (e.g. swaps, options and collars). One of the risks associated with these transactions is that basis differentials may increase over those fixed by the contract, as has happened recently with several of Missouri's LDCs.

Limitations of Hedging Techniques for Small LDCs and for Isolated Systems of Large LDCs with Separate PGA Rates

Small Missouri LDCs may have limitations on their ability to use some hedging techniques. For example, some small LDC systems do not have physical storage available on their systems or their interstate pipeline systems. As a result, these small LDCs are unable to purchase and place natural gas in storage, thereby limiting their ability to use this tool to hedge against price volatility.

Secondly, NYMEX futures contracts have standard minimum volumes of 10,000 MMBtu per contract. Since small LDCs may need only small volumes of natural gas to meet their customers' load requirements, the small LDC may be precluded from widely utilizing futures contracts as instruments for mitigating price volatility.

Small LDCs may only be able to purchase a small number of fixed-price contracts prior to the winter heating season without exceeding the expected load requirements for a warmer-than-normal winter. Further, credit issues may also limit the ability to enter into these contracts.

Small LDCs may also have limited ability to pay the premiums required for call options as they are expensive and may be cost prohibitive to small LDCs whose balance sheets may not meet the credit requirements required to participate in such instruments. Some of these limitations can potentially be addressed through mechanisms like a costless collar or other types of contracting directly with a supplier that can provide the desired price terms.

LDCs serving rural markets must compete for customers against propane competitors. If the price for natural gas, including the cost of financial instruments or other mechanism for insuring against price volatility, becomes too high relative to the propane market, then the LDCs may be unable to retain or attract customers, and the financial viability of the small LDCs' system may be jeopardized. It is particularly important to such LDCs that they be able to compete with their competitors, thereby limiting small LDCs' options for limiting price volatility in these markets.

While these limitation examples refer to smaller LDC systems, they may also be limitations facing larger LDCs on physically isolated systems when the utility does not have a consolidated PGA rate.

III. PGA Rate Changes, Estimated Customer Bill Impacts and Hedging Efforts

Tables no. 1 and 2 in this section illustrate effective PGA rate changes, Staff estimated customer bill impacts this winter versus last winter, and Staff's view of hedging percentages for all the MOPSC regulated LDCs. These tables reflect the PGA rate reductions approved by the MOPSC that took effect prior to the issuance of this report.

Table no. 1 contains the following information, from left to right:

- On the far left side of this table all the MOPSC regulated LDCs are listed. LDC divisions are also listed for LDCs that have PGA rates that vary by division.
- The second column shows effective PGA rates for last winter and this winter. These effective PGA rates are calculated based on the PGA rates in effect, the time periods they are, or are expected to be, in effect, the weather observed or expected during these time periods, and estimated usage during these time periods. All of this information is used to calculate a total number of PGA billed dollars and associated usage over the winter. The total number of PGA dollars billed, or expected to be billed, divided by the usage is the effective PGA rate. The effective PGA rates for this winter reflect the recent PGA rate reductions that took effect prior to the issuance of this report. This winter's effective PGA rate may change based on fluctuations in the natural gas market, actual weather deviations from normal weather, and additional PGA rate changes.
- The third column shows estimated total 5-month winter bills for last winter and this winter. All of these numbers are pre-tax. Estimated winter bills for last winter are based on actual weather observed, estimated usage, and all rates in effect last winter. Estimated winter bills for this winter are based on a projection of normal weather for the remainder of this winter, based on 30-year averages, anticipated usage and rates currently in effect. Staff has not made adjustments to these numbers based on an expectation of warmer than normal weather the remainder of this winter or that customers will reduce their usage in response to high natural gas prices. Either of these factors would reduce winter bill impacts below those given in this table.
- The fourth column shows the percentage increase in the 5-month winter pre-tax bill of last winter versus this winter.
- The fifth column shows the bill increase (as a percentage) given in the fourth column due to the change from a warmer-than-normal last winter to an expectation of normal weather the remainder of this winter; and the percentage change due to PGA rate increases.

- The sixth column shows the total bill increase from last winter versus this winter, premised on a customer taking measures to reduce usage by approximately 5% in response to high natural gas prices. This column is provided for comparison with the fourth column.

Schedule WLG-4

Table 1

1st Column	2nd Column		3rd Column		4th Column	5th Column		6th Column
Missouri Natural Gas Local Distribution Companies (LDC)	Effective Winter PGA 2004-05	Effective Winter PGA 2005-06	Estimated Total Winter Bill 2004-05	Estimated Total Winter Bill 2005-06	Approx. Bill Increase Total Winter Bill 04-05 to 05-06	Estimated Increase Due To Changes in Weather	Estimated Increase Due To Changes in Price	Bill Increase 04-05 to 05-06 With Conservation*
Missouri State Weighted Average	**$0.7915**	**$1.0461**	**$662**	**$818**	**24%**	**-1%**	**24%**	**21%**
AmerenUE	**$0.8157**	**$1.0503**	**$586**	**$700**	**19%**	**0%**	**19%**	**17%**
AmerenUE NGPL	$0.6333	$0.8749	$488	$606	24%	1%	24%	21%
AmerenUE PEPL	$0.7900	$0.9977	$580	$681	17%	0%	18%	15%
AmerenUE TETCO	$0.8900	$1.2685	$610	$794	30%	1%	30%	27%
AmerenUE - MGC/MPC	$1.2102	$1.3986	$656	$735	12%	0%	12%	9%
Aquila	**$0.8290**	**$1.0376**	**$642**	**$749**	**17%**	**-1%**	**17%**	**14%**
MPS-Northern	$0.8244	$1.0453	$641	$732	14%	-4%	19%	12%
MPS-Southern	$0.8423	$1.0760	$634	$755	19%	0%	19%	17%
MPS-SJLP	$0.7764	$0.8549	$690	$748	8%	1%	7%	6%
Atmos	**$0.7471**	**$1.0956**	**$508**	**$691**	**36%**	**0%**	**36%**	**32%**
ANG-Butler	$0.6729	$1.0956	$499	$703	41%	-5%	46%	38%
ANG-Kirksville	$0.7195	$1.1354	$521	$775	49%	0%	49%	45%
ANG-SEMO	$0.8289	$1.1145	$489	$628	29%	1%	28%	25%
Greeley	$0.8182	$1.2775	$644	$862	34%	-5%	39%	30%
UC-BG	$0.5992	$1.0366	$558	$824	48%	0%	48%	45%
UC-HC	$0.5992	$1.0366	$558	$824	48%	0%	48%	45%
UC-Palmyra	$0.5992	$1.0366	$558	$824	48%	0%	48%	45%
UC-Neelyville	$0.6361	$0.8345	$459	$556	21%	1%	21%	18%
Fidelity	**$0.8366**	**$1.1983**	**$613**	**$791**	**29%**	**0%**	**29%**	**26%**
Laclede Gas Company	**$0.7645**	**$1.0593**	**$682**	**$887**	**30%**	**1%**	**29%**	**27%**
LGC Laclede District	$0.7702	$1.0653	$703	$914	30%	1%	29%	27%
LGC Midwest District	$0.7185	$1.0115	$556	$719	29%	1%	28%	27%
LGC Midwest Franklin County	$0.7353	$1.0291	$595	$769	29%	1%	29%	26%
LGC Midwest Proper	$0.7155	$1.0084	$550	$711	29%	1%	28%	27%
LGC Missouri Natural Gas	$0.7259	$1.0192	$573	$741	29%	1%	28%	27%
LGC St Charles County	$0.7401	$1.0339	$608	$788	30%	1%	29%	27%
Missouri Gas Energy	**$0.8249**	**$1.0180**	**$674**	**$774**	**15%**	**-4%**	**18%**	**12%**
MGE-Joplin	$0.8232	$1.0191	$583	$689	18%	0%	18%	16%
MGE-Kansas City	$0.8252	$1.0178	$687	$785	14%	-4%	18%	12%
MGE-St Joe	$0.8251	$1.0178	$726	$830	14%	-4%	19%	12%
Missouri Gas Utility Inc.	**$0.7164**	**$0.9081**	**$662**	**$789**	**19%**	**2%**	**18%**	**16%**
Southern MO Gas Comp	**$0.8639**	**$1.3081**	**$720**	**$962**	**34%**	**0%**	**34%**	**30%**

Table no. 2 contains the following information, from left to right:

- On the far left side of this table all the MOPSC regulated LDCs are listed. LDC divisions are also listed for LDCs that have PGA rates that vary by division.
- The second column shows effective PGA rates for last winter and this winter. This information is the same as provided in the second column of Table no. 1. This column also shows the percentage change in effective PGA rates from last winter to this winter.
- The third column shows total percentage of normal winter supplies that are not exposed to market price fluctuations, by LDC and district. The numbers shown reflect Staff's opinion of these percentages, were determined by Staff in late October 2005, and do not reflect any hedging efforts that any LDCs may have taken after early November 2005. Some of these percentages reflect efforts to adjust numbers provided by the LDC downward to reflect Staff's view that some hedging mechanisms do not provide for a meaningful reduction in market price exposure. One of the notable adjustments in these calculations reflects Staff's view that a basis differential cap is not a hedging approach that provides for protection against market price volatility.
- The fourth column shows percentages of hedging that result from storage volumes and those from financial hedging of flowing volumes. These percentages add up to the percentages given in the third column.
- The fifth column is where LDCs have noted their exceptions to Staff's view of the percentages given in the third column.

Table 2

1st Column	2nd Column			3rd Column	4th Column		5th Column
Missouri Natural Gas Local Distribution Companies (LDC)	Effective Winter PGA 2004-05	Effective Winter PGA 2005-06	Increase In Purchase Gas Adjustment (PGA)	Staff's View of LDC's Total Percent of Winter Hedged Supplies	Percentage of Winter Supplies from Storage	Percentage of Winter Supplies Financially Hedged	Utility Comments
AmerenUE				-			
AmerenUE-NGPL	$0.6333	$0.8749	38%	**80%**	32%	48%	
AmerenUE-PEPL	$0.7900	$0.9977	26%	**85%**	63%	22%	
AmerenUE-TETCO	$0.8900	$1.2685	43%	**71%**	42%	29%	
AmerenUE-MGC/MPC	$1.2102	$1.3986	16%	**85%**	63%	22%	
Aquila				-			
MPS-Northern	$0.8244	$1.0453	27%	**88%**	72%	15%	
MPS-Southern	$0.8423	$1.0760	28%	**81%**	23%	58%	
L&P (NW MO)	$0.7764	$0.8549	10%	**88%**	68%	20%	
Atmos				**47%**	39%	8%	
ANG-Butler	$0.6729	$1.0956	63%				
ANG-Kirksville	$0.7195	$1.1354	58%				
ANG-SEMO	$0.8289	$1.1145	34%				
Greeley	$0.8182	$1.2775	56%				
UC-Bowling Green	$0.5992	$1.0366	73%				
UC-Hannibal/Canton	$0.5992	$1.0366	73%				
UC-Palmyra	$0.5992	$1.0366	73%				
UC-Neelyville	$0.6361	$0.8345	31%				
Fidelity	$0.8366	$1.1983	43%	**0%**	0%	0%	**See Note 1 Below**
Laclede	$0.7645	$1.0593	39%	**55%**	30%	25%	
Missouri Gas Energy	$0.8249	$1.0180	23%	**55%**	35%	20%	
Missouri Gas Utility	$0.7164	$0.9081	27%	**12%**	12%	0%	
Southern Mo Gas	$0.8639	$1.3081	51%	**0%**	0%	0%	**See Note 2 Below**

Note 1: On November 1, 2005, and January 17 and 18, 2006, Fidelity entered into several fixed price contracts which hedged approximately 18% of its expected natural gas for this winter. Earlier in the year, Fidelity had locked in discountes (i.e. basis differentials) on its expected winter loads. In addition, it should be noted that Fidelity does not have storage available on its system. Therefore, Fidelity is not in a position to use storage as a hedge against price volatility. Finally, it should also be noted that the Fidelity natural gas system is being sold to Laclede Gas Company.

Note 2: On January 3, 2006, Southern Missouri Gas entered into several fixed price contracts which hedged approximately 65% of its expected natural gas requirements for the remainder of this winter. Earlier in the year, SMGC had locked in discounts (i.e. basis differentials) on a substantial portion of its winter loads. In addition, it should be noted that SMGC does not have storage available on its system. Therefore, it is not in a position to use storage as a hedge against price volatility.

IV. Current Markets & Impacts on PGA Rates

Over the past 10 years, the price of natural gas on the unregulated wholesale market has increased from an average annual price of approximately $2/MMBtu to nearly $15/MMBtu in some markets during price spikes this winter. Over this span, natural gas prices have remained volatile, ranging from a low of about $2/MMBtu as recently as October of 2001, to new highs on the NYMEX market of over $4 in January 1996, nearly $10 in January 2001, and, recent price spikes to nearly $15 this winter.

The rise in natural gas prices can be attributed to a number of national and international market factors that have significantly altered the balance between supply and demand in the natural gas marketplace. On the demand side, the domestic consumption of natural gas has held fairly steady over the past decade, hovering between 22 and 24 Trillion Cubic Feet (Tcf).[3] However, the consumption mix has changed significantly. While industrial demand for natural gas has actually declined over this period, the use of natural gas to generate electricity has increased sharply.

This increased reliance on natural gas for electric generation has arisen in part because it has been easier and less expensive to satisfy environmental requirements with gas-fueled generation. Moreover, the relatively lower capital costs and shorter construction lead times associated with gas-fueled generation tend to reduce the financial risks associated with constructing more capital intensive units and often present the most favorable alternative for meeting peak requirements. Gas-fueled electric generation will obviously have a less pronounced affect on the demand for natural gas to the extent it is used to meet peaking requirements versus baseload requirements. The rapid increase in the number of unregulated generators in the market, which have been almost entirely gas-fired, has also contributed to this trend. At the same time, it has proved difficult to promote other sources of electric generation in the United States without tax credits or other regulatory incentives. For example, in contrast to other countries that rely extensively on nuclear power to meet their electric needs, the United States has not seen a new nuclear power plant constructed in more than two decades. In recent years the construction of new coal plants has also been hindered by environmental considerations, the perceived financial and regulatory risks associated with the greater lead times and cost of this option, as well as general "not in my backyard" resistance at the local level.

[3] In 2003, industrial consumption accounted for about a third of all domestic consumption (7.4 Tbtu out of 22.1 Tbtu). The next largest share was residential (5.1 Tbtu), followed by electric generation (4.2 Tbtu) and commercial (3.3 Tbtu). Source *American Gas Foundation*. Current projections indicate that industrial, residential and commercial consumption will grow modestly by 2020 (i.e. to 7.7 Tbtu, 6.3 Tbtu and 3.9 Tbtu, respectively), while consumption for electric generation will more than double (from 4.2 Tbtu to 10.2 Tbtu). *Id.*

Indeed, even the most benign forms of energy production, including windmills, have encountered some opposition. However, very recently some of these factors have diminished somewhat and more coal-fired generation is being built. The projected cost differentials between coal and natural gas have been a significant contributor to this trend.

The end result of all of these factors is that over 90% of the new electric generation capacity installed over the past decade has been fueled by natural gas – an incremental increase in natural gas consumption equivalent to what would be required to provide gas service to about 15 million new homes. This, in turn, has placed a steady upward pressure on gas prices, particularly during the summer months when purchases made by LDCs to meet their storage requirements must now compete with the significantly increased demand imposed by summer electric generation requirements.

Notwithstanding these facts, gas-fired generation plays an important and necessary role in peaking and intermediate generation. Coal-fired generation, for example, is not an appropriate or efficient method to meet peak demand for electricity which occurs in the summer months. The concerns expressed above should not be interpreted as a blanket condemnation of gas-fired generation.

Unfortunately, the supply of natural gas has not been sufficient to keep pace with even present demand. Older production fields in the United States have experienced declining production. At the same time, imports of natural gas from Canada have stabilized or declined over the past several years. Exploration for new domestic supplies has also proved problematic. Over the last 20 years natural gas has been generally recognized as a preferred environmental fuel for electric generation and other uses. Nonetheless environmental opposition, regional resistance and federal moratoria on exploration and development have effectively shut off large areas of the country from meaningful development of new supplies. Practically speaking, much of the Eastern Gulf Shelf and Slope, as well as most of the offshore areas and slopes of the Atlantic and Pacific coasts have drilling moratoria that effectively foreclose development of any new resources in those areas. Access restrictions also apply to large areas of the Rockies, where significant natural gas resources have been discovered. Local and regional opposition has also slowed the development of new liquefied natural gas plants that could be used to import additional gas supplies from foreign sources.

Domestic Natural Gas Resources Currently Restricted

(from April 2005 ACEEE Report)

REGION	Trillion Cubic Feet (TCF)	% Restricted From Development
West Coast	21	100%
East Coast	31	100%
Eastern GOM	43	56%
Rockies	346	40%

Two major hurricanes in late August and September, 2005, in the Gulf region further exacerbated this supply situation. As a result of Katrina and Rita, approximately 13% of total US natural gas production was shut-in, resulting in a significant increase in already high natural gas price. While prices have recently fallen, they still remain well above historical levels.

Although difficult to quantify, it is possible that some portion of the upward price volatility in natural gas wholesale markets is due to speculation in these markets by persons who are not producers or users of natural gas. For a general discussion of speculative activity in commodities markets see CFTC Speculative Limits Backgrounder, 3-92, October 2005. The US House of Representatives has recently passed a bill that requires tighter limits on trading; it is uncertain if it will become law. An antitrust case brought against major natural gas producers in Alaska is another example of the national scope of this issue.

These increases in the wholesale price of natural gas have significantly affected both the costs that LDCs across the country have incurred to acquire gas supplies and the PGA rates they charge to recover such costs from their customers.

Expressed in dollar terms, these price and weather-related changes would increase, over last winter, the typical residential customer's total billings for the winter period of November through March, before taxes, by approximately $156. This would, in turn, translate into an average increase of about $31 per month during the heating season for a customer who does not choose to take service under a levelized bill arrangement; and an increase of about $13 per month for a customer electing to take service under such an arrangement. These estimated dollar amounts reflect the PGA rate reductions that took effect prior to the issuance of this report. These mid-winter adjustments to PGA rates dropped the estimated total winter bill to the average customer by approximately $134 (04-05 winter to 05-06 winter increase of approximately $156 vs $290).

V. Public Information & Education Efforts

Since 2000, the MOPSC has been notifying customers, low-income advocacy groups, lawmakers and other interested parties of increasing natural gas prices. These notifications to interested parties have taken multiple forms. Starting in the spring of 2005, the MOPSC increased these efforts significantly in response to what looked like another record jump in natural gas prices. The MOPSC has been very busy with the media throughout 2005 answering questions from the media and lawmakers on natural gas price trends and impacts on customer bills. Much of this information, with information available from low-income advocacy groups and social service organizations, was used in determining the need for Utilicare funding this year.

Since early 2005, Missouri's LDCs have continued to communicate – via a number of different means – that the price of gas continues to be high, and recommending that customers enroll in budget billing plans and take steps to conserve their energy consumption through weatherization and reduced thermostat settings. The communication methods used included radio advertising, bill inserts, and direct mail to elected and public officials. Working with, and assisted by, social service agencies, schools and faith-based organizations, these utilities also made numerous direct presentations to potentially vulnerable groups (*i.e.*, elderly, low-income, disabled) about LIHEAP, other forms of energy assistance, conservation and safety.

In the late summer months, utility personnel participated in a number of television and radio programs promoting conservation and energy assistance efforts in light of the continued high gas prices.

The utilities have continued their communication efforts into the fall, meeting monthly with social service agencies to keep them up-to-date on customer issues and participating in CAP agency poverty simulations. They have also continued to use bill inserts periodically to communicate the need for customers to be aware of the continued existence of high gas prices, the potential benefits of enrolling in budget billing and conservation and to request contributions to "dollar-more" assistance program.

Various utilities have also continued their participation in: HUEE (Heartland Utilities for Energy Efficiency) funded by Kansas City area utilities (including MGE and Aquila) on a per meter basis which creates funding for energy conservation/weatherization education awarded as grants to social service agencies; and in a metro Kansas City group called KC Cash that provides and staffs VITA (Volunteer Income Tax Assistance) sites and educates citizens on obtaining Earned Income Tax Credit (EITC) which is a way for low-income taxpayers to obtain funds. Laclede and AmerenUE participate in similar weatherization programs in their service territories.

Individual company programs vary to one degree or another. In October, Laclede Gas Company's chief executive officer authored an "As I See It" piece about the high gas price environment that was published in the editorial page of the St. Louis Post-Dispatch.

VI. The Current Purchased Gas Adjustment (PGA) and Actual Cost Adjustment (ACA) Process

A detailed background of the PGA and ACA process was provided on pages 70-74 and 79-81 of the "Final Report of the Missouri Public Service Commission's Natural Gas Commodity Price Task Force" (Task Force Report), submitted August 29, 2001. See sections 5.b, 5.c, and 5.e. Because the market has changed substantially in the last four years, it is important to review more recent experience regarding the PGA and ACA provisions.

<u>Changes in the Market Since 2001</u>

Market events over the past year have illustrated how dramatically natural gas market prices can vary and why the PGA process was implemented for natural gas LDCs. The PGA has been in practice since the 1960s when the wellhead price of natural gas was regulated. The federal government began to deregulate natural gas in 1978 and by 1993 all remaining price regulation was removed from wellhead gas supplies. Since 1993, the PGA has allowed LDCs to flow through to their customers both the significant increases as well as the significant decreases which have occurred in the unregulated wholesale market for natural gas. Without some mechanism to address this fuel volatility, like the current PGA process, LDCs would be subject to significant swings in over- and under-collections of actual natural gas cost compared to an embedded natural gas rate. This situation could result in frequent earnings complaints and emergency rate relief cases and could result in significant credit risk to the LDCs. If this situation were not addressed, it could result in pre-payment requirements from natural gas suppliers and other types of credit-related payments that could ultimately impact the delivered price and availability of natural gas to LDCs and their customers. While more recent increases have resulted in utility bills that some customers have found difficult, if not impossible, to pay, the availability of a mechanism for recovering the large costs that LDCs must pay in order to secure gas supplies from third parties has helped to minimize credit-related payment and reliability risks.

It must be emphasized that the PGA continues to be tied to an unregulated market. With regard to this deregulated market, at least two-thirds of a typical PGA factor is made up of the cost of the gas supply itself. Even as far back as the mid 1990s, there was a risk that market prices could exceed $15/MMBtu, but this risk appears to be increasing with the record setting prices in late 2005. LDCs must consider carefully the portions of their portfolios that are exposed to unlimited price fly-ups and the inevitable effect on PGA rates.

It is notable that the Enron saga had not yet unfolded and therefore was not mentioned in the 2001 Task Force Report. The Federal Energy Regulatory Commission (FERC) had not yet begun its investigation into "index pricing". In July 2003, the FERC issued a "Policy Statement on Natural Gas and Electric Price Indices" in Docket No. PL03-03-000, Price Discovery in Natural Gas and Electric Markets. Although improvements have been implemented, there could still be additional transparency with regard to index pricing. Improvements include new reports of volumes and the number of transactions at particular pricing points. Elements that are not known to the public include: who the counterparties are, what types of entities are reporting their trades, how much of the total gas flowing through a particular pricing point is represented by the sample, and how much regulatory oversight will be applied to the reporting and development of the price indices.

Also in 2001, the Commodity Futures Trading Commission (CFTC) had not yet conducted its inquiry into various price reporting practices of natural gas traders. It has been reported that over the past two years the CFTC has settled price manipulation cases with energy marketers for more than $250 million. In October 2005, the United States District Court for the District of Columbia (Misc. No. 05-235(RCL)) issued a Memorandum Opinion pertaining to a subpoena served upon McGraw-Hill that related to the development of natural gas index prices that might have been impacted by an "energy company".

Finally, over the last several years lawsuits have been filed alleging natural gas price manipulation. A recent example is a case filed in the District Court of Wyandotte County Kansas (Civil Action No. 05CV1500) where Learjet, Inc. and Cross Oil Refining & Marketing Inc. are the plaintiffs.

Changes to PGA/ACA Process Following the Winter of 2000/2001

The Office of the Public Counsel requested that their objection to the PGA be noted in this report and their requested language regarding this has been placed in the Additional GW Docket Participant Recommendations and Observations section of this report. Missouri Gas Energy provided a response to OPC's language which is also reflected in the Additional GW Docket Participant Recommendations and Observations section of this report.

On March 26, 2002, the MOPSC established Case No. GO-2002-452 to review PGA clauses in the tariffs of Missouri's LDCs. On June 5, 2003, the MOPSC issued an Order that summarized the general agreement of the LDCs, Office of Public Counsel and Staff. The issues addressed included the following:

A. The LDCs agreed to using the ACA balance every month to determine the amount upon which interest will be charged. This will simplify the calculation, and will base the calculation on factors consistent within the month of calculation (both volumes and unit costs). This ACA mechanism will be reviewed after two winters. Because of Laclede's concerns about lost revenue, Staff will examine Laclede's Deferred Carrying Cost Balance (DCCB) approach in Laclede's next rate case.

B. Generally, the final ending DCCB (both over- and under-recovery) that is calculated bears no interest. This has been called a "flashcut" of the ending DCCB. The parties agreed that in the ACA approach, the ACA balance will continue to bear interest until amortized, known as the "roll-over" approach.

C. Currently, under- or over-recoveries of gas costs do not earn interest until those costs exceed five or ten percent of gas costs depending on which LDC is involved. The parties agreed to eliminate these deadbands, and agreed that interest will accrue from the first dollar either way. The exception to this general rule is that for the small LDCs, Southern Missouri Gas Company and Fidelity Natural Gas Company, the interest balance calculation will include a mutually agreeable deadband.

D. The parties agreed that LDCs shall be allowed to make up to four PGA rate changes per year, one of which will be mandatory. Also, the filings can be no sooner than 60 days from the last PGA rate change. The parties have also agreed that the LDCs will provide workpapers in electronic format when PGA rates are changed. The parties have agreed that the factors used to calculate PGA rates will be stated in each LDC's tariff.

E. The parties agreed that, for purposes of the PGA/ACA process, interest shall be accrued at the prime interest rate, less two percent, but not less than zero percent.

F. Currently, LDC tariffs provide that pipeline refunds to customers will be held until a stated amount is accumulated before the refunds will be flowed back to customers. The parties agreed that pipeline refunds will be flowed back to system sales customers, and transportation customers as appropriate, without the need to accumulate a threshold amount and file a separate refund rate factor. This alternative method contemplates that the ACA approach has been implemented for the purposes of applying carrying costs.

Another concept that was incorporated into all LDC tariffs was the requirement that the PGA rate estimate include consideration of storage and other hedging instruments that could have a stabilizing effect on the PGA estimate. Although this was a critical element in moving away from what historically was a "spot market" driven estimate, some flexibility in the timing and choice of other key PGA estimating variables remains. Some of this flexibility is driven by the fact that some portion of gas purchases in forecasted periods will be based on market prices that can change dramatically between PGA adjustment filing and approval dates.

For example, in some LDC tariffs, the following language appears:
"*The Company will utilize any technique or method it deems reasonable for purposes of estimating the gas cost revenue requirement to be reflective for this component in each RPGA filing.*"

When the proposed PGA rate for an LDC with this provision in its tariffs is reviewed it is necessary to review the reasonableness of the technique or method used as well as the forecasted variables.

Other LDC tariffs are somewhat more restrictive, but still allow a degree of discretion on what variables go into the estimate, along with the date of the PGA filing, which itself can impact the level of market prices used.

The genesis of the flexibility allowed in current Missouri LDC tariffs goes to the idea the PGA rate was indeed an estimate that would ultimately be reconciled, or "trued-up" to actual gas costs. However, as the level of gas costs has risen to previously untested levels, increased scrutiny has been placed upon the development of the PGA estimates themselves.

PGA Rate Estimating Process

It is the Staff's experience that NYMEX and/or First-of-Month Index pricing drives the PGA estimate more than any other factor. This reflects the fact that this variable is the unknown with the greatest impact on forecasted delivered gas costs. If an LDC assumes that its PGA factor will be in effect for the entire winter, it might choose a NYMEX assumption that considers forward price estimates for the entire winter. If the LDC considers that its PGA factor will only be effective for a couple of months, it will tend to use shorter term NYMEX/Index based pricing.

Sometimes so-called "basis" adjustments to NYMEX are explicitly considered in the PGA estimates. Basis refers to the difference between NYMEX pricing (which is referenced to the Henry Hub in Louisiana) and prices where the gas is physically delivered. Recently these price differences have widened due to circumstances in the gulf coast region, resulting in index pricing that could be \$2 to \$3/MMBtu lower than its corresponding NYMEX Henry Hub price. There have been situations where an LDC's "market view" has been lower than available NYMEX estimates, and has filed a lower PGA rate than current NYMEX prices would have implied. If this "market view" is incorrect, a later PGA filing will include a larger over- or under-recovery adjustment.

NYMEX and index price estimates are significant drivers of PGA estimates and at times concerns are raised regarding possible manipulation of the underlying market indexes. Even if concerns regarding alleged speculative influence or alleged misreporting of index price information were to be fully addressed, the natural gas supply and demand balance can, by fundamentals alone, move prices to unaffordable levels.

This is why the requirement to incorporate all hedging results, including storage, in current PGA estimates was so important. Prior to 2001, the PGA estimate was essentially a "point estimate" sometimes not even requiring that lower summer storage prices be reflected in current prices. Prior to 2001, variability in prices between storage volumes and spot market prices was small enough to be acceptable, but this variability is now large enough that such simplifying adjustments cannot be made.

VII. Benefits & Problems of Current PGA / ACA Process & Hedging Rule

Benefits of Current PGA/ACA Process

- Provides reasonable certainty to LDCs that actual gas costs will be reflected in PGA rate;
- Limit of four filings per year moderates month-to-month pricing fluctuations experienced by customers while still providing reasonably accurate pricing signals;
- Symmetrical application of carrying costs provides no reason for LDCs (or customers) to strive for over-recoveries (or under-recoveries) of gas costs over the course of a year;
- Accounting treatment of FERC-ordered refunds and carrying costs has resulted in a simpler and more efficient PGA/ACA process for both the LDC and the regulator; and
- ACA prudence review provides LDCs with reason to make reasonable gas supply, transportation and storage decisions.

Problems with Current PGA/ACA Process

- The ACA review is resource intensive and can be quite lengthy for some cases;
- ACA prudence review as currently administered, provides LDCs with opportunity to recover all its purchased gas costs but no opportunity, outside of an incentive plan, to be rewarded for outstanding performance; because although cost disallowance may be recommended for allegedly imprudent behavior to the customers' detriment, historically no LDC reward has been considered for exemplary results for the customers' benefit (outside of any applicable incentive plan features);
- The MOPSC has little information, outside of observed trends in the market, on changes to PGA rates customers will pay until presented with rates to approve, at a time it can do very little;
- Post-hoc review does not provide a timely opportunity to address problems at a time they can be corrected, and gas costs are so great that LDCs cannot bear the financial impact of adjustments for imprudent actions; and,
- The interpretation of "reasonable" causes much disagreement between the parties.

Benefits of Current Hedging Rule

- Provides a policy statement regarding cost recovery for the use of financial instruments and hedging mechanisms that did not exist prior to the rule's promulgation; and
- Suggests that each LDC should evaluate its market impacts and the impacts on its customers of upward price volatility and set utility specific hedging targets based on its market conditions.

Problems with Current Hedging Rule

- Does not give specific guidelines for natural gas utilities' upward price volatility mitigation program design. For example, what percentage should an LDC seek to price-protect of normal winter purchase volumes? Should an LDC seek to price protect prices for the next two seasons or more? Answers to these and other questions cannot be determined by reading the rule, and thus, determining prudence becomes a matter of opinion.

VIII. Natural Gas Commodity Price and Cold Weather Rule & Long-Term Energy Affordability Task Forces

This docket is not the first time the MOPSC has dealt with natural gas price spikes and their impacts on natural gas customers and the utilities that serve them. In May 1997, the MOPSC sponsored a roundtable, Understanding and Managing Natural Price Volatility, in St. Louis following the price spikes in the 1996-97 winter. In January 2001, shortly after a price spike in the monthly market to nearly $10/MMBtu, the MOPSC created the Natural Gas Commodity Price Task Force in Case No. GW-2001-398. In March 2004, after several winters of progressively increasing natural gas bills for customers, the MOPSC created the Cold Weather Rule and Long Term Energy Affordability Task Force in Case No. GW-2004-0452.

The task force created by Case No. GW-2001-398 developed a policy statement that later became the MOPSC's current natural gas commodity price rule. This task force also recommended changes to the frequency and filing requirements associated with the PGA/ACA process that have been incorporated into the current process described in this report. This task force explored several possible PGA/ACA process structures before arriving at the structure that is now in place for the state. Other recommendations by this group included greater efforts to improve the energy efficiency of households and business and greater funding for LIHEAP and Utilicare.

The task force created by Case No. GW-2004-0452 was given a two-fold objective. The first effort of this task force was to review and recommend appropriate changes to the MOPSC's Cold Weather Rule. This portion of the task force's effort was completed first and all the changes agreed to by the task force participants, and approved by the MOPSC, were made to the Cold Weather Rule prior to the 2004-05 winter season. The second portion of this task force's effort focused on development of recommendations to achieve better long-term energy affordability for customers. As was observed by the task force created in 2001, greater efforts to improve energy efficiency of households and businesses and greater funding for LIHEAP and Utilicare are needed. Other recommendations by this group included efforts to improve accountability of landlords for highly inefficient rental housing and implementation of statewide minimum building energy efficiency codes.

One of the aspects of the high natural gas price problem that continues to be highlighted in these discussions is the fact that neither the state of Missouri nor the federal government controls the wholesale price of natural gas at the wellhead. Some view this fact in a very negative light as the high price of this commodity is clearly impacting the quality of life of many citizens while others believe that any alternative regulatory structures to this market would only further impede efforts to increase supply to bring market prices down. Regardless of your view of this situation, these task forces are attempting to ameliorate circumstances for end-use customers that result from market prices that are, to a large degree, beyond the control of any parties to these proceedings. While the efforts of these task forces are appropriate and time well spent, and their recommendations very appropriate for consideration, it must be recognized that the overall ability to directly address and eliminate the impacts of high natural gas prices are limited.

Appendices:

a. PGA & Hedging Processes in Other States

In the United States natural gas utilities do not generally, outside of some type of incentive plan, make a profit on the gas commodity and transportation cost components of their rates. Due to the volatile nature of natural gas markets it is necessary to have a mechanism to adjust tariff rates periodically to reflect changes in the cost of delivered natural gas. Most Public Utility Commissions (PUCs) have established a Purchased Gas Adjustment (PGA) clause to govern the recovery of these costs for the utilities. Customer's bills typically show these PGA commodity charges separate of delivery charges.

In 2002, the General Accounting Office conducted a survey of 48 state PUCs concerning regulatory and price hedging practices. The report, entitled, "Analysis of Changes in Natural Gas Prices" (GAO -03-46), provides a summary of PUC purchase gas adjustment mechanisms. The survey results show that most states (82%) price natural gas supply by means of a PGA mechanism with reconciliation of actual and estimated costs. Only 3% rely on a fixed price for natural gas supply and 9% use an incentive or performance based rate approach. Also, 59% of the states allow for monthly price changes, 36% quarterly price changes, 1% semi annually and 9% using annual price changes.

A brief review of regulatory practices of several Midwestern states regarding purchase gas adjustments is provided below:

Arkansas
Arkansas Public Service Commission (AR PSC) regulates the natural gas utilities in Arkansas. They employ the traditional PGA clause to govern the recovery of costs for the utilities. Customer's bills separately show delivery charges and commodity charges.

The AR PSC does not require pre-approval, but utilities may seek approval of their buying strategies through the cost adjustment mechanism. Also, the AR PSC does not prescribe the use of financial instruments and will allow recovery of prudent costs associated with the use of financial instruments in the PGA.

Colorado

The Colorado Department of Public Agencies, Public Utility Commission regulates the natural gas distribution utilities and employs an annual Gas Cost Adjustment (GCA) mechanism for the recovery of costs for the utilities.

The Colorado Department of Public Agencies, Public Utility Commission neither requires pre-approval nor grants pre-approval of buying strategies. They do not prescribe the use of financial instruments and conduct prudence audits.

Illinois

The natural gas distribution utilities in Illinois are regulated by the Illinois Commerce Commission (ICC). Illinois employs the traditional PGA clause to govern the recovery of costs for the utilities. The PGA is revised monthly and there is an annual proceeding to determine whether purchases were prudent and to reconcile actual costs. The ICC neither requires pre-approval nor grants pre-approval of buying strategies. Also, they do not prescribe the use of financial instruments and will allow recovery of prudent costs associated with the use of financial instruments.

The reconciliation proceedings state:

> Each utility shall demonstrate that its gas supplies purchased during the reconciliation period were prudently purchased. In, addition, the company shall describe the measures , if any, taken by the utility during the reconciliation year to insulate the PGA from price volatility in the wholesale natural gas market, explaining any hedging strategies utilized, the extent to which the strategies were actually implemented, and the actual impact on the PGA of implementing the strategies."

Several natural gas utilities in Illinois routinely use storage to provide 50% of their winter demand and employ price hedges on about 75% of the winter demand. These utilities have not experienced disallowances related to hedging instrument costs in their PGA's.

Indiana

Indiana Utility Regulatory Commission (IURC) regulates the natural gas distribution utilities in Indiana. The IURC employs the traditional Purchase Gas Adjustment clause to govern the recovery of costs. Small LDC's file for a Gas Cost Adjustments (GCA) on a quarterly basis, and have an annual true-up. Larger LDC's have the authority to change the GCA monthly to reflect market conditions. Other LDC's, that file quarterly, may flex their rates monthly up to $1/MCF from the quarterly filed rate.

In IURC's 2003 Gas Report to the Indiana General Assembly, the IURC noted:

> In its orders, the Commission has encouraged utilities to explore innovative ways to control gas prices using strategies such as hedging, fixed and ratable purchases and efficient use of storage. .... More stable gas prices in a volatile market are desirable and generally considered worth the payment of a slight premium.

Similar to Arkansas, the IURC does not require pre-approval, but utilities may seek approval of their buying strategies. The IURC does not prescribe the use of financial instruments and will allow recovery of prudent costs associated with the use of financial instruments in their GCA.

Iowa

The Iowa Utilities Board (IUB) regulates the natural gas distribution utilities and employs the traditional PGA clause to govern the recovery of costs for the utilities. PGAs are revised monthly and there is an annual proceeding to determine whether purchases were prudent and to reconcile actual costs.

The IUB neither requires pre-approval nor grants pre-approval of buying strategies.

Kansas

The natural gas distribution utilities in Kansas are regulated by the Kansas Corporation Commission (KCC). Kansas employs the traditional PGA clause to govern the recovery of costs for the utilities. The PGA is revised monthly and there are audits to determine whether purchases were prudent and to reconcile actual costs.

The KCC neither requires pre-approval nor grants pre-approval of buying strategies. The KCC establishes a budget that utilities may spend on hedging activities.

Michigan

The Michigan Public Service Commission (MI PSC) approach to gas cost recovery is to have each utility submit an annual Gas Cost Recovery (GCR) Plan for approval, as authorized by MI Public Act 304. The Commission sets a gas cost adjustment level designed to recover the approved gas supply costs for the forthcoming year and allows for true-up of last year's actual costs. This is accomplished through two filings; one filed 90 days prior to implementation and one filed 90 days after conclusion of the GCR period. Both cases are proceedings before an Administrative Law Judge and subject to Commission approval. In addition, the utilities must submit a 5-year forecast of gas supply requirements, source of supply and projection of gas costs.

The MI PSC order states that the utility is obligated to: "...minimize the cost of gas purchased by the utility."

The MI PSC requires approval of buying strategies and prescribes the use of financial instruments. If costs associated with the use of financial instruments are proven to be prudent, the costs are allowed to be recovered.

Minnesota

The Minnesota Public Utility Commission (MN PUC) regulates the natural gas distribution utilities and employs the traditional PGA clause to govern the recovery of costs for the utilities. PGAs are revised monthly and there is an annual proceeding to determine whether purchases were prudent and to reconcile actual costs. The MN PUC neither requires pre-approval nor grants pre-approval of buying strategies.

Summary

In general, most of state PUCs have some form of Purchased Gas Adjustment clause to govern the recovery of costs for the utilities. The mechanisms typically provide an adjustment through the year and a true-up after 12 months. In addition, there are provisions for the PUC to audit the activities of the utility for prudence and potential disallowance of costs. The level of regulation ranges from after-the-fact prudence reviews to pre-approved natural gas purchase plans.

b. Curtailment Practices

Prior to FERC Order No. 636, when pipelines provided a bundled sales service, Title IV of the NGPA protected high priority customers in the event it became necessary to curtail deliveries to customers due to gas supply shortages. When Order No. 636 was implemented, however, the FERC determined that it was no longer necessary to maintain this Title IV protection. Some LDCs requested that FERC "put in place a plan of curtailment that will insure the availability of gas to high priority customers in the event of a gas supply shortage". Instead, FERC found that it was more appropriate to rely on market forces and private contractual arrangements to ensure such availability. As FERC stated:

> ".... in the light of the changes in both the regulatory and legislative environment, as well as changes in the natural gas industry which have transpired since the 1970's, as discussed above, the Commission believes that the exclusive reliance on an end-use allocation methodology is not required to protect the public interest. The Commission believes that with deregulated wellhead sales and a growing menu of options for unbundled pipeline service, customers should rely on prudent planning, private contracts, and the marketplace to the maximum extent practicable to secure both their capacity and supply needs. In today's environment, LDC's and end-users no longer need to rely exclusively on their traditional pipeline supplier. Rather, to an ever-increasing degree they rely on private contracts with gas sellers, storage providers, and others; a more diverse portfolio of pipeline suppliers, where possible; local self-help measures (e.g., local production, peak shaving and storage); and their own gas supply planning through choosing between an increasing array of unbundled service options." (Order No. 636-a, pp. 185-186)

The Commission is of the view that the best protection from the specter of a future natural gas supply shortage is the promotion of an open and competitive wellhead market where all natural gas suppliers are able to compete for gas purchasers on an equal footing, unhindered by the possession of any undue competitive advantage by any class of suppliers. By fostering this goal, Order No. 636 aims to ensure that the benefits of wellhead decontrol, including helping "to ensure adequate supplies of reasonably priced gas in the future" will redound to the benefit of consumers of natural gas to the maximum extent as envisioned by the NGPA and the Decontrol Act. Congress' judgement was that the best protection against, and remedy for, supply shortages was to allow the market to establish the price for gas. If supplies tighten, the price can rise which will stimulate new investment to bring new supplies to market. (Order No. 636-a, p. 188). ...

> *Finally, in the event of an unexpected and sudden force majeure supply shortage, Title III of the NGPA vests in the President ample authority to effectively assure that available gas supplies are allocated and transported to meet critical needs.* (Order No. 636-a, p.189); emphasis supplied.

As the foregoing suggests, regardless of what private contractual arrangements an LDC may have with its suppliers, its ability to actually obtain the gas it has contracted for is always subject to potential action by the President to reallocate such supplies elsewhere. Indeed, the standard contract under which gas supplies are typically bought and sold on the wholesale market contain force majeure provisions that specifically excuse the supplier's obligation to deliver gas if such failure is due to "governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of law promulgated by a governmental authority having jurisdiction." *See* Section 11 of the North American Energy Standards Board ("NAESB") Base Contract for Sales and Purchase of Natural Gas (Standard 6.3.1).

Given the significant disruptions in supply capacity recently exhibited by Hurricanes Katrina and Rita, the possibility of such a governmental reallocation of gas supplies appears to be a possibility with a high enough probability that this scenario must be considered. This is particularly a concern if demand for natural gas were to substantially increase in certain parts of the country as a result of severe weather or additional developments further impact supplies. Should that happen, the tariffs under which some of Missouri LDCs operate would permit them to purchase gas from their transportation customers if it had invoked the first four steps of their emergency curtailment plans by: (1) interrupting sales service to interruptible and basic transportation customers; (2) stopping the delivery of gas to firm sales and firm transportation customers whose loads can be met by alternate fuel capability; (3) requesting voluntary load reductions; (4) limiting schools and industrial customers to only those gas supplies needed to maintain building protection and dormant facility use; and (5) exhausting all other efforts to obtain gas supplies from other sources. Under such circumstances, transportation customers would be reimbursed at the lower of the cost of their alternate fuel or no. 2 oil.

In view of the increased potential that such a reallocation could occur in the future, with its associated impact on supply availability, it would be beneficial to consult with interested stakeholders in advance on how this curtailment process could be best coordinated. Such an approach should help to minimize disputes and enhance the LDC's ability to protect human needs customers consistent with the basic goal underlying the curtailment process.

c. Additional GW Docket Participant Recommendations & Observations

Ameren and Atmos Recommendation: Combine all of the distribution systems for an LDC into a single PGA.

Rationale for Recommendation: Historically, some systems have been kept separate due to differing PGA rates. In today's market, the benefits of providing the most effective commodity cost hedging for all customers outweighs the necessity to continue to segregate customers in small systems from the advantages of larger systems.

Larger gas distribution systems have the ability to employ a more diverse portfolio of hedge instruments to provide price stability for customers. Because of their size, small gas distribution systems have limited hedge instruments and, since they have few packages to hedge, cannot rely upon dollar cost averaging. In addition, some distribution systems may also be at a disadvantage due to limited storage availability, and less liquid supply markets. A larger, aggregated portfolio allows the LDC to take advantage of the most effective storage and markets available. This leverage would provide more efficient hedging, provides cost protection for the ratepayer and also eases the administration burden for each LDC and Staff.

Office of the Public Counsel Comment Regarding PGA:

"Both the Office of Public Counsel and MGUA argue that the PGA clause is itself unauthorized by Missouri law because: (1) it constitutes single-issue ratemaking in that it permits the rates to be changed based on a consideration of only a single factor -- gas fuel costs -- in contravention of the statutory requirement that the PSC consider all factors in setting rates; and (2) it constitutes improper retroactive ratemaking, in that it improperly permits the rate charged to be changed to include past unrecovered fuel costs. ... [In addition, the] use of a PGA clause constitutes an abdication of the PSC's ratemaking function because it permits the utilities rather than the PSC to set rates in regard to fuel costs, and that for the same reason it runs afoul of the rule requiring utilities to have a fixed rate on file rather than a variable one, for it permits the rate to vary with the cost of gas." (State ex rel. Midwest Gas Users' Ass'n v. PSC, 976 S.W.2d 470, at 477).

Missouri Gas Energy Response to OPC Comment Regarding PGA:

In response to the OPC comment paragraph on the PGA, MGE requested that the report show that, "In its opinion, the Western District of the Missouri Court of Appeals ruled that '. . . all of these arguments are without merit.' Id."

Missouri Public Service Commission Staff Comment:

This report does not address whether each LDC should develop a comprehensive gas supply plan. This report does not reflect any agreement on what constitutes a comprehensive natural gas supply plan nor does it reflect an agreement on the elements of a comprehensive natural gas supply plan. The report also does not address any agreement on how or whether each LDC should document a comprehensive gas supply plan.

In order to have an adequate hedging plan, Staff believes that a LDC must have a comprehensive natural gas supply plan. Unless a LDC has documented its supply requirements under varying weather conditions and the impacts of pricing on its business and its customers, the LDC cannot determine whether its hedging plan is effective.