Additional Considerations Regarding PBR

Gas Procurement vs. Delivery Charges

The role of PBR in gas procurement may be quite different from the PBR role related to delivery costs for a LDC. A LDC's delivery costs are fairly predictable; the hope is that PBR will create incentives to reduce those costs below the level occurring under traditional regulation. For gas supply costs, however, volatility is a concern that is as big as (or bigger than) price level. Hedging can reduce volatility, but in the long run, it is debatable whether it will reduce the price level. And there is a trade-off, in that stable prices can be achieved by paying a premium over expected market prices. Hence, "success" may be harder to define in terms of gas procurement results.

Elective Hedging

The choice between hedged and unhedged gas prices is not an "all or nothing" proposition. Utilities could offer longer-term stabilized prices (e.g., for one-year, two-year or three-year periods) to customers as an option and acquire corresponding hedges for customers who want that option. This probably works best for commercial customers, but if the cost of administration is low, residential customers could be offered a similar option.

Stabilizing Delivery Costs

Commodity-based delivery charges can have an undesirable effect in colder-than-average winters. Delivery charges are usually based on normal weather. In cold winters, customers buy more gas and pay more for delivery charges, even though such costs are essentially fixed in nature.

Offering customers a fixed annual charge, based on normal weather volumes, would be a way of avoiding unnecessarily high bills during very cold winters. The price, of course, is that in warmer-than-average winters the fixed charge bill would be higher than the commodity-based charges. However, in warm winters customers would still benefit because they purchased lower-than-average volumes of gas.

VI. Recommended Parameters For Incentive Design

The task force believes that there are potentially additional efficiencies that may be gained from properly designed incentives for gas related costs and energy efficiency. Further, the task force agrees to the following general parameters for the design of incentive mechanisms.

- Incentives should be targeted to areas of operation in which the LDC's actions have a meaningful impact in reducing costs, enhancing net revenues, or in providing other benefits that are in the customers interest, such as energy efficiency programs.
- Additional profit from an incentive plan should only be awarded for cost reducing or net revenue enhancing actions by the LDC, and efficiency gains in excess of those that the LDC should reasonably be expected to undertake absent the incentive.
- Incentive mechanisms may be an effective tool when the level of compensation required by the LDC, for engaging in cost reducing actions does not exceed the net benefit consumers receive for the level of cost reductions that can be reasonably anticipated to result.

- Incentives should be structured to allow the LDC sufficient flexibility to respond to changing market conditions.
- Incentives should be structured to promote a portfolio targeted at mitigating overall cost or improving energy efficiency.
- Incentives should be structured to ensure that consumers receive benefits by aligning rewards to the LDC with outcomes desirable to consumers.
- Incentives should be structured to align the risk to the LDC with the risk faced by consumers in an effort to ensure that consumers are made no worse.
- Baselines should be considered for components of the incentive plan where inherent levels of performance exist. Factors relevant to establishing a particular baseline may include historic performance, changing market conditions, comparisons to similarly situated firms, or desired public energy policies.
- Consumers have expressed a strong preference for more stable natural gas prices. In the area of procurement, incentives should be targeted toward stabilizing prices by mitigating upward price volatility.
- An incentive mechanism should allow a relatively lower reward to the LDC when information linking the LDC's actions with beneficial outcomes cannot be clearly verified and a relatively higher reward to the LDC when information linking the LDC's actions with beneficial outcomes can be clearly verified. Even if provided at lower levels, however, the case for utilizing incentives as opposed to prudence reviews may be strongest where a link exists but it is difficult or costly to evaluate the precise extent of the link.
- Incentives should be structured to avoid creating a situation where the firm's management has less incentive to perform efficiently from either a customer or shareholder perspective.
- The total incentive package should be structured to ensure that when individual components are implemented together they do not produce undesirable results.

VII. Current Incentive Programs and Alternative Incentive Programs

Currently, MGE, Laclede Gas Company and AmerenUE have approved Gas Supply Incentive Plans. The incentive programs that currently apply for Missouri's LDCs are focused on providing an incentive for the LDC to reduce the cost associated with specific components of performing the merchant function. Individual incentives that are believed to contribute to overall cost mitigation apply to the areas of gas procurement, transportation related services and off-system sales. In contrast, however, some suggest that ultimately an incentive program should only reward the LDC's efforts in the event that the overall delivered cost of gas falls below some benchmark performance. The benchmarks may be based on historic performance, expected price or costs, and/or comparisons to other LDCs.

VII (1) (A) Incentive Programs that focus on rewarding activities believed to mitigate overall cost.

<u>Pros</u>

This approach creates a more direct and therefore, arguably, a more effective link between the reward and the preferred action than does a program under which the opportunity for reward depends on exogenous factors such as the achievement of other LDCs or the exact relationship at a point in time between current and historic price levels.

Cons

Under this type of Program the LDC can receive additional profit even when consumers are paying more than they have historically or are paying more than consumers served by other LDCs.

Individual Components

Providing Incentives For Options and Fixed Price Futures Contracts

When fixed price or options contracts are utilized, the Company determines its involvement in the design, timing, and amount of activities intended to mitigate market volatility and escalating gas costs. These contracting practices provide the opportunity through financial instruments to cap or lock-in a future price for natural gas when it appears favorable. The use of these instruments also does not necessarily require that the LDC take delivery of physical supplies in order to cap or lock-in prices.

Pros

- These pricing arrangements ensure gas costs do not exceed a specified maximum rate that appears favorable based on the information known and available when the decision was made.
- Because these instruments do not necessarily require delivery of physical supplies, they can act as a complementary mitigation technique to physical hedging measures.
- These instruments can be used to mitigate the commodity cost of gas which is by far the largest component of a consumer's bill. Therefore, depending on the volumes covered these instruments have the potential to significantly mitigate rate shock.

Cons

- What appeared to be a prudent decision when executed may result in financial benefit or detriment based on future market conditions. When capping or locking-in a predetermined future price, LDCs have no assurance of what the *spot market price* will be at the later date. Therefore, a detriment will occur at the later date if the locked-in price exceeds the actual market price or if incurring the cost of an options contract was unnecessary.
- Public utilities do have an obligation to attempt to mitigate overall costs and price spikes. LDCs must analyze all methods available to achieve these goals, including financial instruments, fixed price contracts, and storage among others.

Providing Incentives For Demand Charges
LDCs have the ability to negotiate with suppliers to lower the fixed monthly charge for reserving the availability of firm gas supplies. These charges do vary significantly but typical values are around 2-5% of total gas costs.

<u>Pros</u>

- Although these charges tend to rise as the cost of the commodity rises, a LDC has a greater ability to reduce, through negotiations and other strategies, the level of demand charges it actually pays. Any reduction is beneficial to customers and incentives can ensure that such reductions are maximized.
- Absent an incentive mechanism, it is difficult to determine whether the LDC has done the best job possible in minimizing the level of demand charges it pays, consistent with maintaining reliable service.
- Non-regulated firms performing identical functions are routinely allowed to profit from their successful negotiation of favorable demand charges.
- The negotiation of gas supply demand charges is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Since the potential savings to be achieved through the successful reduction of gas supply demand charges are significantly greater than the savings opportunities available in connection with most of the LDC's non-gas costs, it is important that incentives be provided in this area so that a commensurate proportion of the LDC's limited resources will be allocated to such efforts.

<u>Cons</u>

- Demand Charges constitute a small fraction on the total cost of gas. Rewarding efforts in this area of procurement may detract from efforts in areas that could produce more meaningful results.
- Some effort in this area should be expected. It may be difficult to ascertain the LDC's effort in this area and to design a reward that does not over compensate.
- Since demand charges constitute a relatively small proportion of a customer's bill, if this reward applies to volumes bought at volatile spot prices, there may be a perception that the LDC is profiting without meaningfully containing costs.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Pipeline Discounts
LDCs have the ability based upon competitive factors to negotiate reductions in the maximum transportation or storage rates established by the FERC or the MoPSC.

<u>Pros</u>

- Pipeline Discounts can constitute a significant savings to ratepayers.
- LDCs can, through hard bargaining, the creation of leverage and other strategies influence the level of pipeline discounts they are able to achieve. Since pipelines must provide evidence to FERC in recovering costs associated with discounts to specific customers, there is some reasonable assurance that the LDC's efforts contributed to any discounts achieved.

- It is difficult to determine, through an after-the-fact audit, whether the LDC obtained the most favorable pipeline discounts possible.
- Non-regulated firms are routinely allowed to profit from their successful efforts to negotiate favorable pipeline discounts.
- In the event baselines are established in this area, they should not be set so high that they effectively eliminate any practical incentive.
- The negotiation of pipeline discounts is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Since the potential savings to be achieved through the successful negotiation of pipeline discounts are significantly greater than the savings opportunities available in connection with most of the LDC's non-gas costs, it is important that incentives be provided in this area so that a commensurate proportion of the LDC's limited resources will be allocated to such efforts.

<u>*Cons*</u>

- LDCs are obligated to attempt to achieve cost reductions and should therefore pursue pipeline discounts in the normal course of business.
- Pipelines that are not fully subscribed have an incentive to increase subscription through the use of discounts.
- Large LDCs may have leverage as a buyer allowing them to enjoy relatively larger discounts than smaller pipeline customers.
- If this incentive is utilized a reasonable baseline should be established. Baselines that are set too low will provide an unnecessary windfall to the LDC.
- Just as it may be difficult to gauge whether the LDC's have maximized the efficiencies that can be potentially achieve in this area, it may also be difficult to identify a direct link between the LDCs actions and the ultimate level of cost reductions obtained.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Mix Of Pipeline Services

Altering the mix of pipeline services refers to renegotiating or restructuring pipeline supplier service contracts

<u>*Pros*</u>

- In some cases, LDCs can reduce their overall transportation costs by pursuing strategic changes in the mix and level of their transportation services from various pipelines. In some cases, there may be moderate price risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportunities that is commensurate with the potential benefits to be achieved. It also makes it more likely that the LDC will take more risks to achieve such savings by providing it with an opportunity to benefit if taking those risks produces favorable results.
- Absent an incentive mechanism, it is difficult to determine whether the LDC has devoted the right level of resources to pursuing such opportunities or has, in fact, maximized the efficiencies that can be potentially achieved in this area.

- A mix of pipeline supplier incentives may also be helpful in preventing any perverse incentives to obtain lower gas commodity costs at the expense of higher transportation costs.

<u>*Cons*</u>

- Ratepayers have financially contributed to the level of reliability contained in a LDC's existing pipeline transmission and storage services and should not incur additional costs when such contracts are renegotiated or restructured based on changing market conditions.
- Providing any substantial incentive in this area may reduce the LDCs focus on areas that can provide more meaningful reductions in customer bills.

Providing Incentives For Capacity Release

When purchasing capacity, an LDC is reserving a maximum amount of pipeline space to be made available for use in serving the potential demand in its service area. Capacity release provides the LDC the ability to release (i.e. market) unutilized capacity and receive revenues to mitigate pipeline reservation charges. Capacity release was implemented by the FERC as a result of FERC Order No. 636.

<u>Pros</u>

- In some cases, LDC can increase their overall revenues from capacity releases by devoting additional resources to the task and by pursuing strategies designed to take advantage of market conditions. In some cases, there may be risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportunities that is commensurate with the potential benefits to be achieved for its customers. It also makes it more likely that the LDC will take more risks to achieve such savings by providing some upside potential if it does.
- To the extent that an incentive promotes greater capacity release the LDC gains the opportunity to recapture a portion of its sunk costs.
- It is difficult to determine through an after-the-fact audit whether the LDC obtained the most capacity release revenue possible.
- The release of pipeline capacity is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Non-regulated firms are routinely allowed to profit from their successful efforts to release capacity.
- The percentage of capacity release revenues that the LDC is permitted to retain, the volatility of such revenues, and the potential elimination of any effective incentive if baselines are set too high, are all appropriate factors to consider in determining whether and to what extent any baseline should be established for such revenues.

Cons

- Capacity release should occur as a normal method of reducing costs.
- Just as it may be difficult to gauge the whether the LDCs have maximized the efficiencies that can be potentially achieved in this area, it may also be difficult to identify a direct link between the LDC's actions and the ultimate level of cost reductions obtained.
- There may be a tradeoff between off-system sales and capacity release which provides an incentive to unduly favor one over the other. Off-system sales and capacity release should be addressed together in a rate case.
- Of particular concern would be the possibility of selling product via "capacity release" and creating an unreasonable profit at the expense of the consumer for product actually used.
- If this incentive is utilized a reasonable baseline should be established. Baselines which are set too low will provide an unnecessary windfall to the LDC.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

Providing Incentives For Off-System Sales

Off-system sales are any sales of natural gas, or natural gas bundled with pipeline transportation service, to parties other than the LDC's transportation customers or their agents.

Pros

- In some cases, LDC's can increase their overall revenues from off-system sales by devoting additional resources to the task and by pursuing strategies designed to take advantage of market conditions. In some cases, there may be risks associated with such initiatives. The availability of an incentive can promote favorable results in this area by ensuring that the LDC devotes a level of resources to pursuing such opportunities that is commensurate with the potential benefits to be achieved for its customers. It also makes it more likely that the LDC will take more risks to achieve such savings by providing some upside potential if it does.
- To the extent that an incentive promotes greater off-system sales the LDC gains the opportunity to recapture a portion of its sunk costs.
- It is difficult to determine, through an after-the-fact audit, whether the LDC maximized off-system sales revenues.
- The sale of gas to off-system customers is a relatively new function and may not necessarily be an essential component of an LDC's public utility obligations.
- Non-regulated firms are routinely allowed to profit from their successful efforts to sale gas.
- The percentage of off-system sales revenues that the LDC is permitted to retain, the volatility of such revenues, and the potential elimination of any effective incentive if baselines are set too high, are all appropriate factors to consider in determining whether any baseline should be established for such revenues.
- Any concern regarding a potential bias toward capacity releases or off-system sales can be easily addressed by establishing identical sharing percentages for both transactions in the PGA process.

Cons

- Off-system sales should occur as a normal method of reducing costs.
- Just as it may be difficult to gauge the whether the LDCs have maximized the efficiencies that can be potentially achieved in this area, it may also be difficult to identify a direct link between the LDCs actions and the ultimate level of cost reductions obtained.
- There may be a tradeoff between off-system sales and capacity release which provides an incentive to unduly favor one over the other. Off-system sales and capacity release should be addressed together in a rate case.
- If this incentive is utilized a reasonable baseline should be established. Baselines which are set too low will provide an unnecessary windfall to the LDC.
- Non-regulated firms do not have the benefits and obligations of the regulatory compact.

VII (1) (B) Incentive Programs that focus on rewarding outcomes.

Pros

- Ensures that LDCs can only receive profit in connection with their gas supply and transportation management efforts when customers pay less than historic rates or less than customers of other LDCs.
- This option may be more understandable and palatable from a customer's perspective because it focuses on what matters to customers - the overall cost of delivered gas.
- This option diminishes the potential for the LDC to pursue profit opportunities that do not result in cost savings on the bottom line of a customer's bill.
- This option reduces concerns regarding perverse incentives created by interrelationships that may exist between individual components of an incentive plan that rewards individual actions targeted at reducing costs.

Cons

- Focus on pure outcome, without regard to impact of market forces or the degree of the LDCs ability to affect outcome, may reduce or eliminate any tie between the incentive being provided and the actions that management can actually take to produce favorable results.
- Removing an incentive for the LDC when market prices are rising will eliminate incentives to efficiency and innovation when they are most needed.
- Basing incentives on how an LDC performs on an absolute basis or over time compared to another LDC is inappropriate if the uncontrollable factors affecting that performance vary significantly from one LDC to the next.
- Efficiency gains and cost reductions may be meaningful and beneficial even when they do not lower cost below historic levels or the rates charged by other LDCs.

Option 4.c) CONSERVATION/EFFICIENCY INCENTIVES

VII (2) Incentive Programs that focus on energy efficiency.
Energy efficiency is often viewed as an energy resource like coal, oil or natural gas. In contrast to supply options such as drilling for more natural gas or mining coal, energy efficiency helps contain energy prices by curbing demand instead of increasing supply. Balanced portfolios that address demand reduction in addition to increased supply can be designed to be good for the consumer (through lower energy costs) and the utility company (through incentives that do not reduce profits from a reduction in sales).

Missouri ranks in the top 5 states in terms of total potential energy savings and energy savings per home based on a 1998 Alliance to Save Energy study of states that have not adopted an energy code.

Effective energy efficiency programs can address the barriers that inhibit customers from making investments in energy efficiency improvements – lack of money or competing demands for available funds, up-front costs are more real than long-term savings and lack of technical expertise. Energy efficiency programs can address low-income weatherization, low-cost customer financing for energy efficient building improvements and appliances, information, new home construction practices, reduced air infiltration, heating system rebates, domestic hot water, lighting and windows. Efficiency programs may be funded by earmarking a percentage of a utility company's revenues for the purpose of providing consumers with rebates and low-cost financing for energy efficient improvements or by offering consumers direct tax incentives.

For example, in addition to low-income weatherization, some of UtiliCorp's energy efficiency programs in Iowa are listed below (UtiliCorp d/b/a Peoples Natural Gas (PNG) in Iowa).

<u>Customer Financing for Energy Efficiency</u> – This program offers Peoples Natural Gas residential customers the opportunity to purchase and receive the advantages of an energy efficient furnace and other high efficiency products at a competitive interest rate. To qualify, residential customers must own and live in a home that is occupied year round, and have a good credit history and utility payment record. Application for financing is processed in a day or so, payment is included as part of the monthly gas bill and remains the same for the term of the loan. No down payment is required, there is no penalty for early pay off, interest rate is currently at 8 percent, and the term of the loan can be set at 24, 36, 48, 60, 72 or 84 months depending on equipment efficiency.

Residential Efficiency-Heating System Rebates – The program is designed to encourage residential customers to install high efficiency natural gas heating systems by providing financial incentives to replace standard equipment. Rebates are provided for the following qualifying equipment: set-back thermostats (up to $75), gas furnace with set-back thermostat (93-93.9% annual fuel utilization efficiency up to $275; 94% or greater up to $375), high efficiency gas boilers (90% annual fuel utilization efficiency $200), mid-efficiency gas boilers with set-back thermostats (83% annual fuel utilization efficiency up to $275) and integrated space and water heating systems (84-90% combined annual efficiency $300-500). Rebate amounts vary depending on product efficiencies and are issued to the person invoiced for the equipment. Homeowners and renters are eligible to participate in the program.

Domestic Hot Water for the Residential Sector – This program includes retrofitting of existing gas water heaters with a series of low-cost measures including water heater tank insulation wrap, water heater pipe insulation, low-flow showerheads, faucet aerators and water heater temperature set back to 120 degrees. This program is provided at no additional cost to the residential customer living in single and multifamily units. Renters must have owner approval to participate. Customers apply for these services by filling out and returning bill inserts that go out regularly to promote the program or call a toll free number to schedule an appointment. A contractor calls the customer within 4 to 6 weeks.

Residential New Construction – This program promotes energy efficient new home construction practices by providing incentives to residential customers based on the specification and installation of energy efficient measures to reduce air infiltration. Rebates are provided for roof insulation (R48) $0.125/sq.ft.; wall insulation (R24) $0.20/sq.ft.; windows (double or triple pane low E) $14/opening; reduced air infiltration (0.5 air change per hour) $250. Applications require an itemized invoice, verification of R-values from builder, blower door test results if applicable and a scaled down copy of the new home blueprint.

Trees Program -- Communities and non-profit organizations that sponsor energy-saving tree planting programs as environmental projects can receive grants from Trees Forever on behalf of PNG and PNG works with the Iowa Department of Natural Resources to sponsor Trees for Kids and Trees for Teens Programs. Trees Forever is responsible for evaluating requests to fund a project and distributing funds provided by PNG.

Commercial and Industrial Customer Rebates – This program provides commercial and industrial customers with a financial incentive to replace standard equipment with energy efficient systems. The rebate amount is based on a portion of the incremental cost between a standard product and a high efficiency unit and depends on the peak demand reduction, annual energy use reduction and annual energy cost savings.

Pros

- Energy efficiency programs provide assistance to customers in helping to reduce their energy usage and utility bills. This is particularly important when energy prices are higher and more volatile.
- Long-term costs to the system may be lower by reducing the distribution companies' costs to upgrade their systems.
- Lower energy costs improve the economy and the competitiveness of businesses and increase customers' discretionary income, raising their standard of living.
- Using energy efficiently provides additional economic value by preserving natural resources and reducing pollution.

Cons

- Use of ratepayers' money to pay for participating customers' savings may cause concerns among non-participating ratepayers.
- Incentive programs may limit customer investment to those energy efficiency products that are supported by the program.
- Incentive programs may encourage customer investment in energy efficiency products only when funding is available from the programs.

In addition to the customer impacts, another issue that must be addressed in establishing workable programs targeted at energy efficiency is the impact of such programs on the LDC. An LDC may have little incentive to facilitate programs designed to reduce energy use because in doing so the LDC may be reducing its revenue base.

There may be ways to attain the benefits of energy conserving initiatives while also mitigating the potential negative impact on an LDC. For example, in cases of over-earnings, a portion of the revenue reduction could be retained in exchange for the establishment or expansion of programs targeted at energy efficiency. In instances in which a more ubiquitous program is desired, LDCs could be offered an incentive to offset some portion of lost revenues.

While this section of the task force report is intended to provide a general discussion of incentives designed to promote energy efficiency and the pros and cons of providing such incentives, The task force believes that this subject warrants a more comprehensive review. Therefore the task force recommends that the Commission direct its Staff to initiate an investigation into currently utilized energy efficiency programs, the effectiveness of those programs and the financial impact of those programs on the participating LDCs.

Option 4.d) INTEGRATED GAS PURCHASING PLANS

VIII. The Roles of Information and Verification

Central to the issues of regulatory oversight of gas purchasing, consumer protection and incentive design are the roles of information and verification. In this section of the task force report we first summarize the differing perspectives regarding the significance of information and verification and address the task force's proposal for an integrated gas purchasing plan.

Under the existing ACA review process, reviews are to be based on information that was available at the time a LDC made purchasing decisions. Despite Staff's, OPC's and intervenor's obligation to limit reviews in this way, LDCs have suggested that the timing gap coupled with disadvantageous market events may inspire greater or unfair scrutiny during the review process. On the other hand, Staff and OPC have expressed frustration with the level of documentation and the availability of information to them in fulfilling their respective roles in the review process.

A related issue arises in the context of incentive design. Asymmetric information is inherent in the interaction between the parties. The LDC participates in the market on a daily basis, interacting with suppliers and pipelines, negotiating new contracts, and monitoring weather forecasts and other exogenous factors that impact the LDC's purchasing strategies and activities. Without thorough tracking of these factors, some believe there can be no easily discernable link between specific incentive mechanisms, the LDC's actions and the ultimate impact of those mechanisms and actions in lowering gas costs.

In an effort to address the issues of information and verification, the task force has proposed implementation of an integrated gas-purchasing plan. An integrated gas-purchasing plan is not, per se, an incentive plan. Rather, it is a process by which an LDC explicitly documents its expected natural gas demands for the ensuing year; the supply, transportation, and storage options available to meet those expected needs; its expectations for the market price of gas for the ensuing period, as well as the relative costs of the necessary physical hedges and optional financial hedges; and the possible courses of action available if, as it frequently does, the natural gas market changes. Thus, integrated gas purchasing plans are not fixed at a single point in time, but are flexible planning tools that must adapt to changing market conditions. The process also provides for the LDC to provide the plan to Staff and OPC for review and comment. Staff and OPC would comment early in the gas supply year on the effects of plans on both reliability and cost, in the hopes of reducing the likelihood of adverse results and ACA audit adjustment disputes. No LDC in Missouri currently has such a program in place. AmerenUE and UtiliCorp, which operates Missouri Public Service Company and St. Joseph Light & Power, are in the process of establishing such practices.

Pros

- The integrated gas supply plan should promote an improved quality and timeliness of information provided to the Staff and OPC enhancing their ability to fulfill their respective roles in the regulatory process.
- The integrated gas supply plan should help reduce disincentives faced by LDCs in their gas purchasing functions. These disincentives are addressed elsewhere.
- Additional positive financial incentives for securing natural gas on terms favorable to consumers can be added as a separate element in the gas supply process, if deemed desirable. The design of such incentives is also discussed elsewhere by this subgroup.
- This proposal would help to provide evidence of the link between any incentive mechanism, the LDC's actions and the ultimate impact on gas prices.
- An integrated gas-purchasing plan should contain contingency alternatives in the event of extraordinary variances in price or availability.
- An integrated gas-purchasing plan would provide advance information to the Staff and OPC, thus making the "prudence review" less onerous.
- An integrated gas-purchasing plan substantially limits, as a practical matter, the possibility of Staff or OPC using hindsight in prudence reviews.

Cons

- This proposal may unreasonably limit the LDC's ability to respond to changing market conditions and involve the state to an excessive degree in determining the procurement strategies followed by the LDCs they regulate.
- The recommendations given by Staff and OPC as a result of this process are likely to be the determinative factor in the procurement strategy ultimately pursued by Missouri LDCs since few are likely to pursue courses of action that are inconsistent with those recommendations given the likelihood of a prudence disallowance if the alternative course of action results in an unfavorable result.
- Innovation by individual LDCs may be discouraged through the potential adoption of whatever standards and practices are deemed most suitable by Staff and/or OPC. Under such circumstances, the impact of detrimental practices on customers would be magnified.
- This proposal may result in additional labor hours and expense to the LDC and ultimately customers.
- Even though the process exposes the LDC to a greater risk of prudence disallowance if it does not follow the recommendations of Staff or OPC, the proposal does not provide any firm assurance that prudence reviews will not be sought by someone even if the LDC does follow their recommendations.
- The implementation of an integrated plan review process is contrary to the Commission's previous rejection of similar proposals.
- This proposal does not sufficiently restrict the Staff or OPC from raising issues in the ACA process.

5. What Happened This Winter

5.a) Historical Natural Gas Prices and Heating Costs vs. the 2000-01 Winter

Most U.S. residential and general service natural gas customers are not aware of the per unit price they pay for natural gas or how much gas they are using day-to-day or month-to-month. These same customers are often economically sophisticated in other ways. They are more likely to know how much they paid for a gallon of gasoline this week compared to last week, and how many miles they drove their vehicle this week compared to last week. Thus, the typical driver can probably look at how much they spent for gasoline this week compared to last week and determine if it was due to different driving or different prices or both.

Based on numerous phone calls, letters, e-mails, and public meetings it is possible that these same people do not routinely do the same analysis of natural gas bills, or at least, not to the same degree. One reason that higher natural gas bills may surprise customers is that natural gas is consumed passively rather than actively. It is also paid for after usage has already occurred rather than before. Some natural gas customers may have made a decision to buy a higher efficiency furnace, install insulation, or use a setback thermostat for the heating system, but afterwards the furnace and water heater run automatically, controlled by thermostats. The customer does not normally make decisions daily on the purchase or use of natural gas.

Heating Degree Days (HDDs[5] base 65F) measure cold weather for the purpose of estimating space-heating demand. HDDs for the natural gas customer's heating system are like miles for a driver's automobile. The more miles traveled the more gasoline is burned and, the more HDDs the more natural gas a heating system uses to maintain the temperature set on the thermostat. Thus, the number of HDDs in a period of time determines the volumes of natural gas consumed by a space-heating customer during that time. The relationship between HDDs and space heating demand is virtually linear, once the temperature drops below an average of about 65 F.

In the heating season of 2000-01 (November 2000 through March 2001) typical residential natural gas customers had a limited awareness of the price of natural gas and their usage until receiving their bills in December 2000 and January 2001 with substantial increases over the same months in the previous heating season. Missouri was typical of most states in the U. S. during this heating season. Prior to the 2000-01 heating season, Missouri experienced the three consecutive heating seasons 1997-2000 with the fewest total HDDs in the last forty-one years

5 For natural gas usage for space heating, the most commonly used measure for weather is HDD. In theory, the heating requirements for one day having 10 HDD or two days each having 5 HDD will be the same. HDD are computed from a daily mean temperature (DMT). DMT is calculated from the daily maximum (T_{max}) and daily minimum (T_{min}) temperature, HDD are only positive or zero. For DMT at or above the base, 65 °F, HDD are zero. For DMT below 65 °F, HDD are the difference between DMT and 65 °F.

In equation form,

$$DMT = (T_{max} + T_{min})/2,$$
$$HDD = 65^\circ - DMT, \quad \text{if } DMT \leq 65$$
$$HDD = 0, \quad \text{if } DMT > 65.$$

(1960 – 2001), i.e. 1997-98, 34th; 1998-99, 40th; and 1999-00, 41st; (see Chart 5.1). The most recent Missouri heating season with a weighted HDD[6] total as high as 2000-01 was 1995-96. Each of the four heating seasons after 1995-96 was successively warmer than the previous. This HDD decline made natural gas bills during the heating season decline, as less natural gas was needed for heating. This decline in HDD was also the general pattern nationally. As the demand for natural gas decreased, the commodity price of natural gas in the unregulated wholesale natural gas market remained between $1.75 and $3.00 per Mcf (1,000 cubic feet of gas, approximately equivalent to 1,000,000 Btu). An Mcf is not the unit of usage that appears on most customer bills, but it is a common unit for markets. Most customers are familiar with Ccfs or Therms which represent about one tenth of an Mcf. A Ccf is equivalent to 100 cubic feet of gas and a Therm is equivalent to 100,000 Btu. A Ccf is often very close to the same as a Therm (assuming a heat output of about 1000 Btu/cubic foot). Over the last five years retail natural gas customers enjoyed the benefits of an unregulated wholesale market when the decline in HDD resulted in a decline in the need for space heating.

This decline in the demand for natural gas for space heating tended to compensate the market for increases in the demand for natural gas for other uses such as the generation of electricity. There was also a decline in demand as a result of the decline in the amount of gas put in storage during the non-heating season (April – October). This decrease in storage injections carried into the summer of 2000, as the wholesale price of gas increased.

During the summer of 2000 the cost of natural gas was high and many market participants held off making significant injections anticipating a drop in natural gas prices. This anticipated drop in prices did not materialize. Some of the reduction in storage injections may have also been due to a perception that the need for storage gas was not as great given the recent mild winters. The events of this winter have emphasized the importance of storage in any well designed gas supply portfolio.

For most of the US, including Missouri, the winter of 2000-01 contained the coldest combined November and December on record (see Chart 5.2). This early record cold placed an unexpected strain on gas supplies and the wholesale market responded. The remainder of the heating season (January – March) was not so severe, but the HDD total for the heating season was the ninth highest in forty-one years. The increase in HDD from 1999-00 (3,443 HDD) to 2000-01 (4,608 HDD) was the largest consecutive season-to-season difference in HDD in the last forty-one years. Statistically speaking, the return interval for a difference of this magnitude (1,165 HDD) is over 140 years. Once again, the pattern of HDD for November and December, and the total heating season in Missouri, was similar to the national pattern.

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6 The weather stations used to compute Missouri weighted HDD are Cape Girardeau – 0.039661, Columbia – 0.101227, Conception – 0.005233, Kansas City – 0.295548, Kirksville – 0.014681, Springfield – 0.056022, St. Louis – 0.487627.

The volumes of natural gas consumed by the typical Missouri residential customer during the 2000-01 winter heating season greatly exceeded those of the previous season. The typical Missouri residential natural gas customer consumed a greater volume of natural gas in every month of the 2000-01 winter vs. the previous winter (see Chart 5.3). This winter's estimated total for a typical residential customer was 107.6 Mcf compared to the 1999-00 winter's total of 86.5 Mcf.

Chart 5.1 - Historical MO State Weighted HDDs

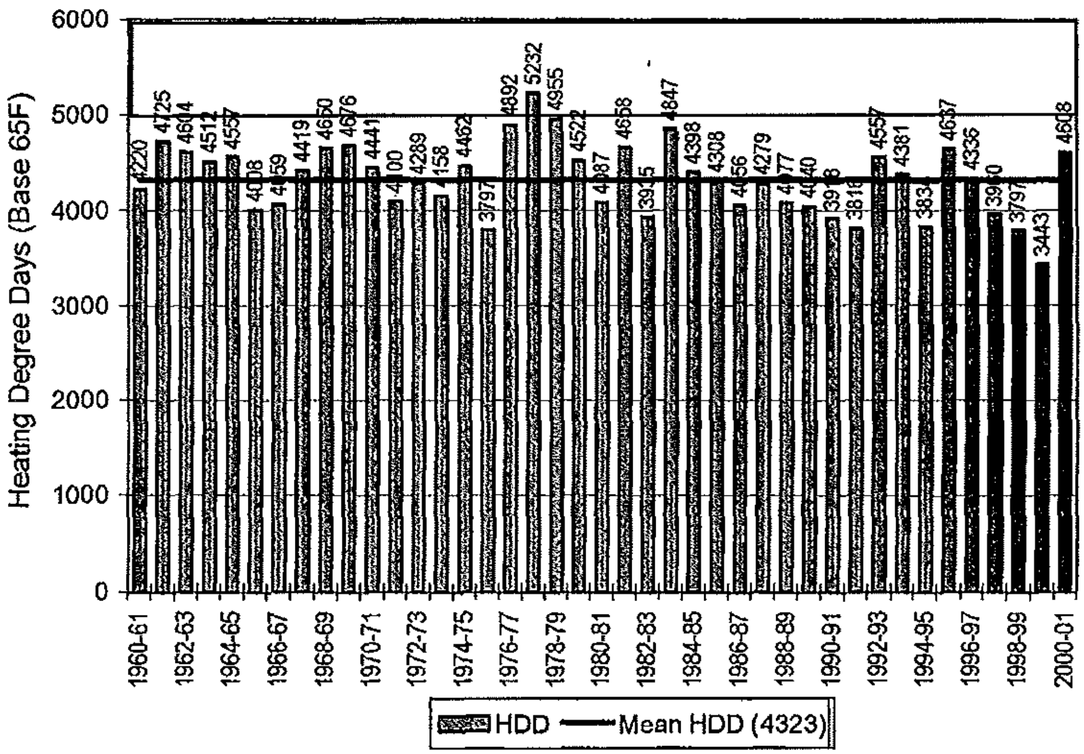


Chart 5.2 -Monthly MO Weighted Heating Degree Days

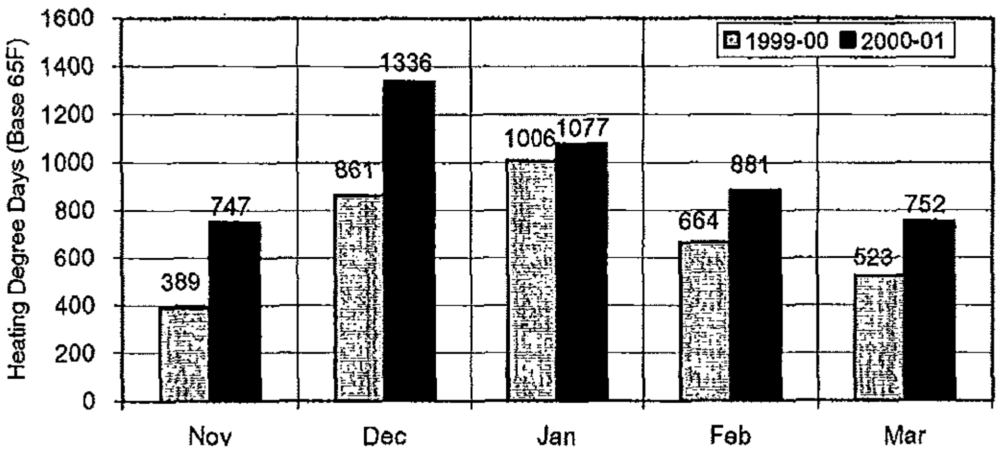
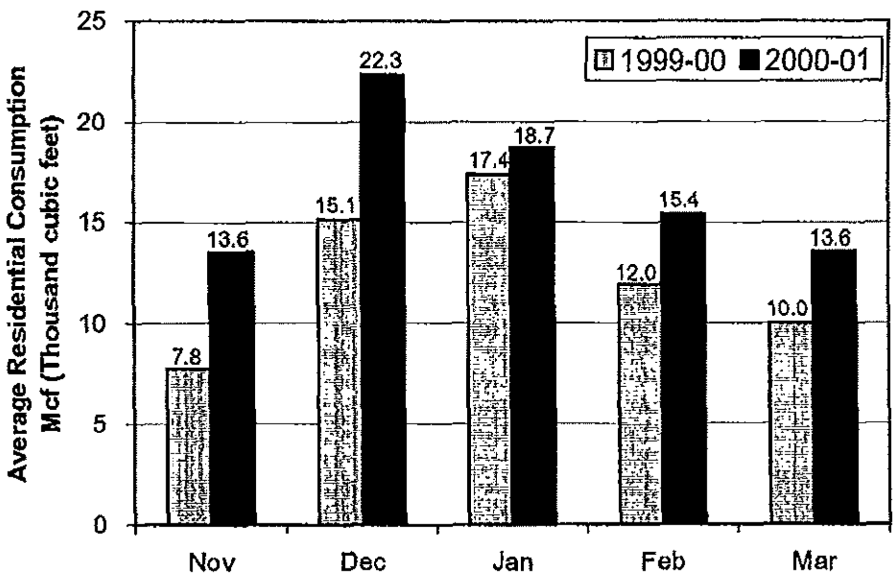


Chart 5.3 - MO Residential Natural Gas Customer Heating Season Monthly Usage



Additionally, retail natural gas customers encountered the negative consequences of a volatile unregulated wholesale market for natural gas during the 2000-01 winter heating season. The wellhead price of natural gas has been relatively low with an average of around $2/Mcf since this price was deregulated over a decade ago. The commodity price of natural gas began to go above historic highs in the summer of 2000 when it went above $4/Mcf in June, $5/Mcf in September, and then in November it went over $6/Mcf (see Chart 5.4).

This increase in volumes used and costs per unit are critical to natural gas consumers since 65 to 80 percent of the typical natural gas customer's bill is a result of the recovery of the commodity and transportation costs of natural gas.

The mechanism that links the retail customer of a regulated Missouri LDC to the commodity price of natural gas in the unregulated national wholesale market is the LDC's Purchase Gas Adjustment (PGA) rate and the type of pricing mechanisms that are in the contracts each LDC negotiates with its suppliers. The PGA mechanism allows LDCs to incorporate the commodity price they pay into the rates they charge their customers.

In October 2000, Missouri's three largest LDCs filed record high winter PGA rates in the range of \$6.44 to \$6.77/Mcf. The state weighted average PGA rates of regulated LDCs was \$6.68/Mcf with a range from \$3.77 to \$8.50/Mcf. The differences between PGA rates is due to several factors, some of which are a) overall system size and mix of the LDCs customer base, b) availability and use of storage capacity, c) how LDCs rely on index priced gas, fixed priced gas, and the LDC's transportation contracts, d) the LDCs hedging strategies as well as the different percentages of supplies from these sources and e) the LDCs willingness to incur large under recoveries rather than raising PGA rates in mid-winter. The 1999-00 winter MO weighted average PGA rate was \$3.89/Mcf. The state weighted average PGA rate in November 1999 was not much different than the PGA rate going back to November 1997 (see Chart 5.5). The details of the PGA mechanism established by the PSC will be discussed in the next section of this report.

From the inception of unregulated wholesale interstate natural gas in the 1980s until 2000 the commodity price generally varied from \$1 to \$3/Mcf. In the last five winters the commodity price might be above \$3/Mcf for a only few days in two or three months of the winter. Under these circumstances a change of \$.50/Mcf was significant. In addition to the commodity cost, LDC PGA rates include about \$1/Mcf in transportation cost, so the PGA rates before 2000 were in the \$2 to \$4 range (see Chart 5.5).

In addition to the PGA rate, LDC retail customers pay a monthly customer charge and a per unit distribution rate (a.k.a. Margin Rate) to the LDC. These rates are set in general rate cases by the MoPSC. In the winter months these rates add about \$3.50 to \$4.00/Mcf to the typical residential customer's cost of gas. So, in the winter months of 1999-00 the state weighted retail residential price of natural gas was between \$5.75 and \$6.48/Mcf (see Chart 5.4).

At the end of 2000, after two months of extraordinarily cold weather and continued reports of extreme storage withdrawals, the commodity price of natural gas spiked to nearly \$10/Mcf in late December. Speculation that the market would moderate and criteria for filing for unscheduled winter PGA rate changes resulted in LDCs not filing until January 2001 for PGA rate increases to reflect this extraordinary spike in prices.

Chart 5.4 - State Weighted Residential Retail Composite Price of Natural Gas and NYMEX Commodity Price of Natural Gas

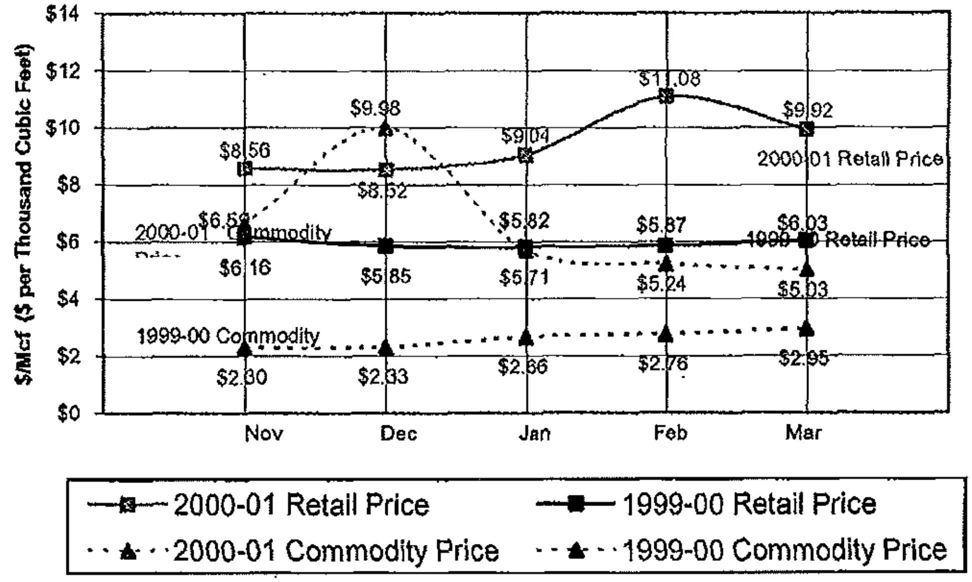
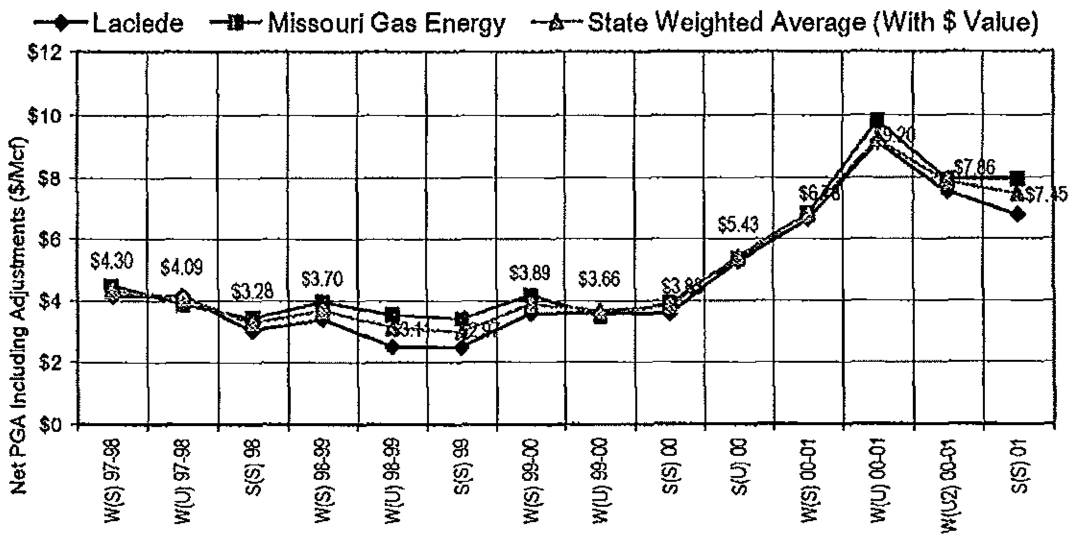


Chart 5.5 - MO Regulated Gas Utilities Net PGA for General Service Customers



Seasonal Filing -- W-winter (November - March), S-summer (April - October), (S) scheduled, (U) unscheduled

The Scheduled Winter PGAs become effective about November 1.
The Scheduled Summer PGAs become effective about April 1.
Unscheduled PGAs may become effective anytime during the season.

An unusual phenomenon occurred in December 2000 when the commodity price of natural gas was higher than the retail price of natural gas (see Chart 5.4). This resulted in many LDCs incurring a deficit because they were paying more for natural gas on the unregulated wholesale market than they were receiving from their customers through regulated rates. As will be explained in later sections, LDCs are allowed to recover this deficit in addition to bringing their PGA rates in line with the current commodity price when they file for unscheduled winter PGA rate changes (see Chart 5.5, *W(U) 00-01*). The further increase in PGA rates in January resulted in monthly gas bills remaining high in January, February, and March even though these months did not experience the record breaking cold of November and December (see Chart 5.6).

Chart 5.6 - MO Residential Natural Gas Customer Heating Season Monthly Bills

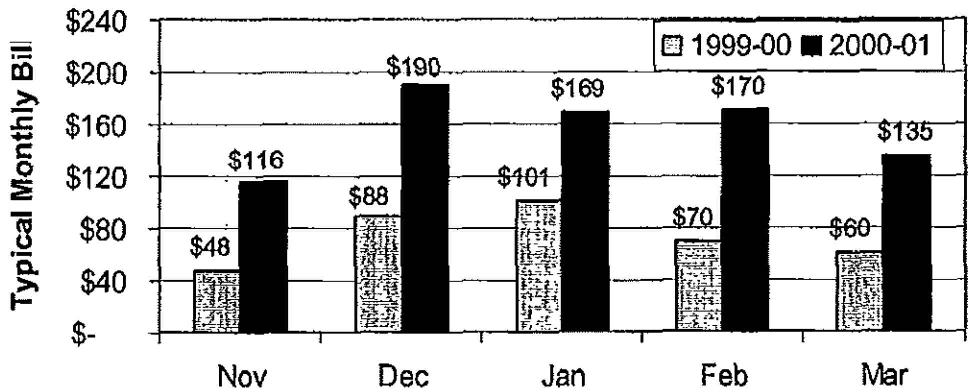
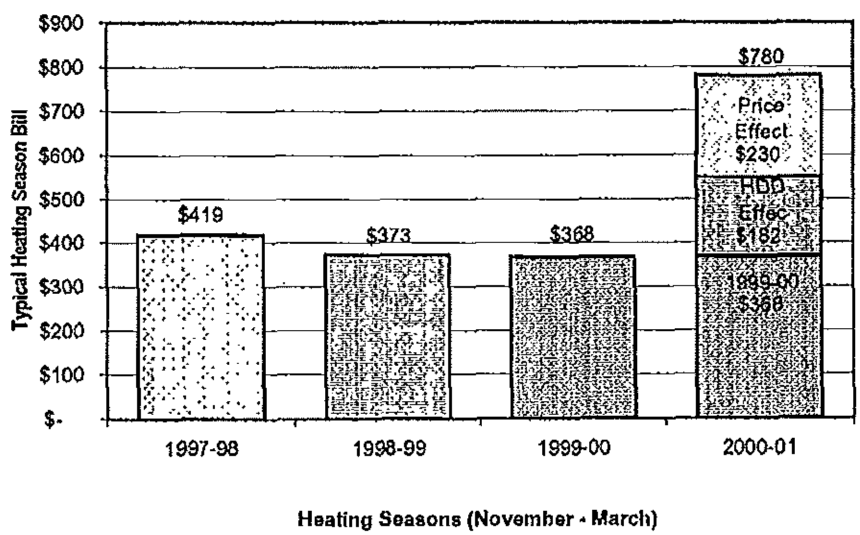


Chart 5.7 - MO Residential Natural Gas Customer Typical Heating Season Bill



By the end of the 2000-01 heating season, the typical residential customer's bill was more than twice their bill for the previous heating season (see Chart 5.7).

A similar pattern is seen when PGA rates and typical residential natural gas bills are compared to the two earlier heating seasons. In November 1997, the MoPSC changed its rules so that LDCs filed for scheduled PGA rate changes in November and March. At that time the state weighted PGA rate was $4.30/Mcf. The heating season was mild and the estimated bill for the heating season of 1997-98 was $419 for the typical residential customer. The state weighted PGA rate was below $4.00 for the next two years as the wholesale market reflected the low demand due to mild heating seasons in most of the nation. This combination of mild heating seasons and a relatively steady PGA rate resulted in declines in the bills for Missouri's typical residential customer for the next two heating seasons (see Chart 5.7). Consequently, Missouri's LDCs and their customers had not experienced either the prolonged extreme cold or the high PGA rates in the previous three winters that occurred before the 2000-01 winter.

The increase in the heating season natural gas bill for the typical Missouri residential customer was from $368 in 1999-00 to $780 in 2000-01. This increase of $412 has two primary components. The HDD effect, $182, is the increase in the bill as a result of more volumes used due to colder weather; and the price effect, $230, is the increase in the bill due to the higher retail price per Mcf of natural gas in 2000-01 compared to 1999-00 (Chart 5.7). The higher retail price was the result of Missouri LDC's higher PGA rates, and the higher PGA rates were due to the higher commodity cost of natural gas in the unregulated wholesale natural gas market. The increase in commodity cost was due to a number of factors but the primary factor was the record cold in November and December 2000 that affected most of the states east of the Rockies. This record cold occurred when the commodity price had already eclipsed $5/Mcf and led to the first sustained increase in space heating demand for natural gas nationally in five years. This increased demand caused nine weeks of sustained or increasing commodity prices from $4.50/Mcf the last week in October 2000 to $9.98/Mcf the last week of December 2000.

5.b) Components of the Purchased Gas Adjustment (PGA)

The PGA Clause was instituted for Laclede Gas Company in 1962. Other LDCs received approval for their PGA Clauses in subsequent years. Most states have PGA Clauses (46 of 50 states), although the mechanism is unique as a ratemaking mechanism in that the costs that are applicable to it are not considered in the general rate case process. Costs that are subject to recovery through the PGA Clause typically include gas supply, pipeline transportation, and pipeline storage costs.

Gas supply costs are usually described as the cost of the wellhead supply and are usually paid to producers or marketers. Various pricing provisions can apply to this supply, but the market for the commodity is the most volatile part of the PGA and makes up the largest portion of the costs that are included in the PGA. The United States Congress in the Natural Gas Policy Act of 1978 (NGPA) set up various categories of gas production and associated ceiling prices in an effort to encourage further production. Natural gas flowing in interstate commerce was deregulated in stages by Congress, which adopted a phased-in deregulation for gas discovered after 1977. The Natural Gas Wellhead Decontrol Act of 1989 (NGWDA) removed NGPA price controls. On January 1, 1993, all remaining price controls were lifted and wellhead natural gas prices became fully deregulated.

Gas transportation costs are paid to interstate or intrastate pipeline companies for delivering the gas commodity from production areas to the city-gates of the LDCs. The FERC regulates the maximum transportation rates for interstate pipeline companies. The MoPSC regulates the rates of Missouri's intrastate pipeline companies. These rates are usually composed of primarily fixed charges based upon a contracted maximum daily capacity, and a smaller per unit charge for delivered quantities. Prior to 1993, interstate pipelines offered a "bundled" service, which included both gas supply and transportation as part of a delivered product to the LDC. In April of 1992 the FERC issued Order 636, which required interstate pipelines to "unbundle " and move away from the selling of gas supply. At this time, the regulated portion of interstate pipeline companies does not hold title to the gas itself. These interstate pipeline companies operate as transportation businesses.

Pipeline storage costs are paid to interstate pipelines for storage services that are also regulated by the FERC. The rates paid are often based upon a combination of daily delivery capability from storage and capacity levels reserved for storage. Another alternative to interstate pipeline storage is "off-system" storage where rates are negotiated between parties. When an LDC owns its storage facilities, the facility's operational costs and plant costs are typically recovered outside of the PGA Clause in a general rate case process.

Generally speaking, the PGA Clause recovers "gas costs" that are necessary to get the gas from the wellhead to the LDC distribution system. The PGA Clauses in Missouri are contained in the PSC approved tariffs for each LDC.

Before 1997, LDCs were authorized to make monthly PGA filings. After the winter of 1996-1997, most LDCs revised their tariffs so that only 2 scheduled filings, a summer and a winter filing, were authorized per year. An unscheduled filing was allowed if certain thresholds were met. PGA rates are estimates of the gas costs at the time the filings are made and include the effects of storage withdrawals and any over or under recovery that the LDC may be experiencing. The estimated PGA rates are trued-up, or reconciled, to actual gas costs on an annual basis. This reconciliation involves a comparison between what the Company actually paid for gas versus the amounts it has billed to customers through PGA rates. The return of any over-recovery starts in the fall of the year, just subsequent to the end of the applicable annual Actual Cost Adjustment (ACA) period. The regular adjustments of each LDC's PGA rates are directed at achieving a dollar-for-dollar match of gas costs expenses and revenues.

PGA rates typically include several subcomponents. The ACA rate is simply the result of the annual comparison of actual gas costs the LDC paid versus the estimated gas costs that were billed out to customers through the PGA. This residual factor is added or subtracted to the current PGA factor. The refund factor is developed by taking into account refunds received from interstate pipelines for overcharges in their authorized FERC rates. In some instances an additional rate is separately identified for take-or-pay and transition costs which resulted from FERC actions to restructure parts of the gas industry.

PGA filings are subject to an expedited review and are often effective in less than 30 days from when they are filed. The Commission's approvals are made on an "interim" basis and subject to review and refund. Prudence reviews are not conducted on these estimates but are subsequently performed on the actual gas costs when the LDCs make their annual ACA filings.

<u>5.c) Actual Cost Adjustment (ACA) and Prudence Audit Process</u>:

The Actual Cost Adjustment (ACA) audit was first implemented in the early 1980s. It was designed to reconcile actual gas costs to revenues recovered through the PGA Clause. The ACA uses a 12-month time frame for the reconciliation. The total actual gas costs from gas supply, transportation, and pipeline storage invoices, is accumulated and compared to the billed revenues for the corresponding time period. The closing date is typically in the summer when natural gas usage is at a minimal level.

When a LDC incurs more expense than it has recovered in PGA revenues, an "under-recovery" occurs. If the LDC collects more PGA revenues than its actual expenses for the period, an "over-recovery" occurs. The ACA factor is calculated by taking the under or over recovery and dividing it by an annual volume of sales. This factor, or rate, is then applied to billings over a subsequent 12-month period in order to refund, in the case of an over-collection, or charge, in the case of an under-collection.

Under the traditional ACA process, the goal was to ensure that the LDC passed-through the actual cost of gas, no more and no less. Since PGA rates are established based upon estimates, and weather and price almost always vary from estimates, it is necessary to true-up to actual. The ACA filing is developed once per year and is submitted as part of the annual winter PGA filing.

This annual ACA filing is audited to establish that the expenses and revenues claimed are in compliance with authorized PGA tariffs and reflect accurate levels of expenses and revenues supported by underlying source documentation. This audit includes a review of invoices, allocations among customer classes, allocations among other jurisdictions, storage accounting, billing records, and other supporting data and workpapers. Compliance adjustments, such as error corrections, can result from this review.

Another critical aspect of the audit is a reliability review. Each LDC must plan to meet a colder than normal winter period and extreme weather conditions on peak days. This requires a careful evaluation of usage characteristics and temperature data. This demand data is compared to supply and transportation/storage resources available to determine if an excess or shortage of capacity exists. Usually, reliability is related to cost in that the greater the reliability, the greater the costs for a particular supply or transportation service.

Finally, a prudence review is performed as part of the audit. Since the expenses incurred in an ACA are separate and apart from the normal rate case review, the expenses must be reviewed to ensure they are reasonable. The review is retrospective. It is not designed to be a hindsight review but is guided by the Commission's "prudence standard". This standard has been established for quite some time and has been clarified in several cases.

To test the reasonableness of a company's costs, the Commission uses a standard of prudence. This standard was discussed in the Commission's Report and Orders in the cases concerning the Callaway and Wolf creek nuclear power plants. In the Callaway case the Commission determined "that the appropriate standard was enunciated by the New York Public Service Commission in Re: Consolidated Edison Company of New York, Inc., 45 P.U.R., 4th, 1982". In that case on page 331, the New York Commission rejected an earlier 'rational basis' standard in favor of a reasonable care standard:

> "More recently, and in cases more directly on point, we have articulated the standard against which a utility's conduct in circumstances such as these should be measured as follows: '...the company's conduct should be judged by asking whether the conduct was reasonable at the time, under all the circumstances, considering that the company had to solve its problem prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the tasks that confronted the company. Case 27123, Re: Consolidated Edison Company of New York, Inc., Opinion 79-1, January 16, 1979."

The Missouri PSC went on to state: "The Commission will assess management decisions at the time they are made and ask the question, 'Given all the surrounding circumstances existing at the time, did management use due diligence to address all relevant factors and information known or available to it when it assessed the situation?'" The Commission did not adopt a standard of perfection and would not rely on hindsight.

In Kansas Power and Light Company Case No. GR-89-48 the Commission indicated that the Company "has the burden of showing its proposed rates are just and reasonable." The Company "has the burden of showing the reasonableness of costs associated with its rates for gas." Further it stated, "The standard is that when some participant in a proceeding creates a serious doubt as to the prudence of an expenditure, then the company has the burden of dispelling those doubts and proving that the questioned expenditure was prudent."

Finally, in Western Resources Case No. GR-93-140 the Commission decided to clarify the parameters of gas costs prudence reviews. It stated:

> "The Commission is of the opinion that a prudence review of this type must focus primarily on the cause(s) of the allegedly excessive gas costs. Put another way, the proponent of a gas cost adjustment must raise a serious doubt with the Commission as to the prudence of the decision (or failure to make a decision) that caused what the proponent views as excessive gas costs. The Commission is of the opinion that evidence relating to the decision-making process is relevant to the extent that the existence of a prudent decision-making process may preclude the adjustment. In addition, evidence about the particular controversial expenditures is needed for the Commission to determine the amount of the adjustment. Specifically, the Commission needs evidence of the actual expenditure(s) incurred during the ACA period resulting from the alleged imprudent decision. In addition, it is helpful to the Commission to have evidence as to the amount that the expenditures would have been if the LDC had acted in a prudent manner. The critical matter of proof is the prudence or imprudence of the decision from which expenses result."

5.d) Why Did Natural Gas Prices Start High & Spike in January 2001

Despite the recent decline in natural gas prices (in August 2001, a little over $3/Mcf), soaring 2000-01 winter heating bills vividly reminded Missouri energy consumers of how quickly natural gas prices can change. Industrial, commercial and residential consumers across the state felt the sharp increases in wholesale natural gas prices that fluctuated between $2 to $3/Mcf in the 1999-00 winter and than suddenly more than quadrupled to nearly $10 during 2000-01 winter. The end of the 1999-00 winter marked the beginning of an unprecedented increase in natural gas prices that was fueled by a "perfect storm" of circumstances that impacted the supply and demand of natural gas. These factors included extraordinary weather, electric generation, storage levels, the economy and how natural gas supplies had grown in the years previous to last winter. Speculation purchases by market participants may have also played a role. To better understand what happened in the 2000-01 winter, attempts should first be made to understand the circumstances leading to the price increases that occurred.

Basic Economics – Supply and Demand

Natural gas wholesale prices are generated by activities in an unregulated market where supply and demand largely dictate the outcome. The supply and demand imbalances of last winter's national natural gas markets were largely the result of previous years where relatively low demand and natural gas prices dampened interest in the commodity's exploration and development. Regarding domestic natural gas supplies, it is important to note that the U.S. DOE reports that natural gas resource basins are considered adequate to meet most domestic demand for several more decades. The tightness of supplies last winter was largely the result of relatively low natural gas prices and the associated lack of exploration and production of these natural reserves to keep up with potential demand. Transportation capabilities of pipelines to national demand centers and some supplies also played a role. Chart 5.8 displays the gradual increase in natural gas consumption over the 1990's through which time the commodity's prices remained relatively stable and low while imports increased to offset flat natural gas production. Thus, supply constraints emerging steadily over the years, the relatively recent increase in demand for natural gas, and extraordinarily cold weather all resulted in a market price increase for natural gas as suppliers raised the wellhead price to what the market would bear in what some would call a "seller's market". Chart 5.8 depicts flat natural gas production during the 1990's while consumption and net imports of the commodity increased.

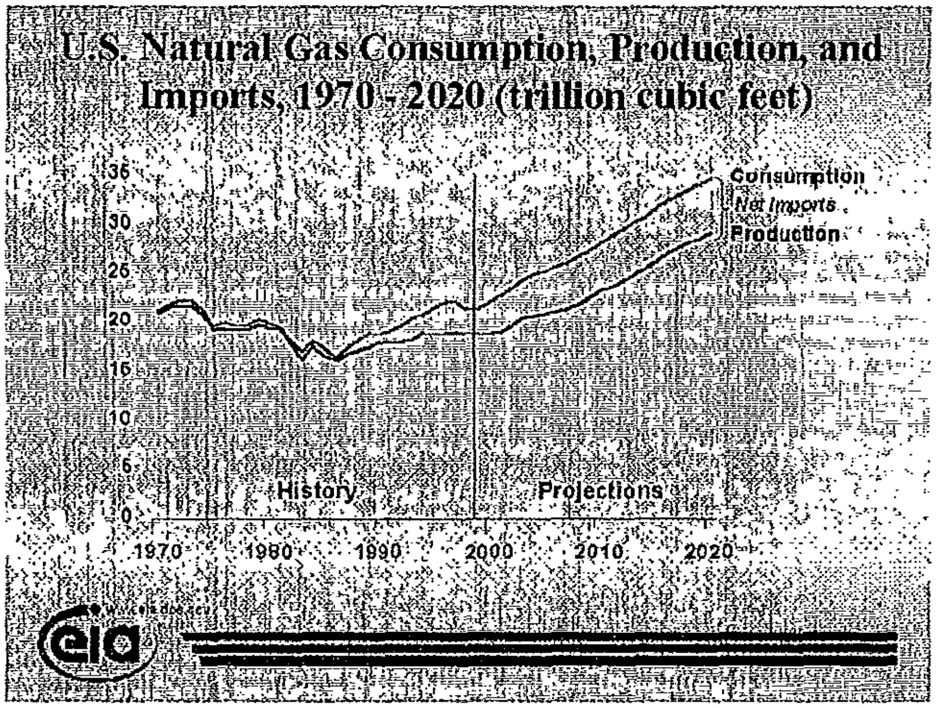


Chart 5.8 – Natural Gas Consumption, Production, Imports
Source: Energy Information Administration, DOE

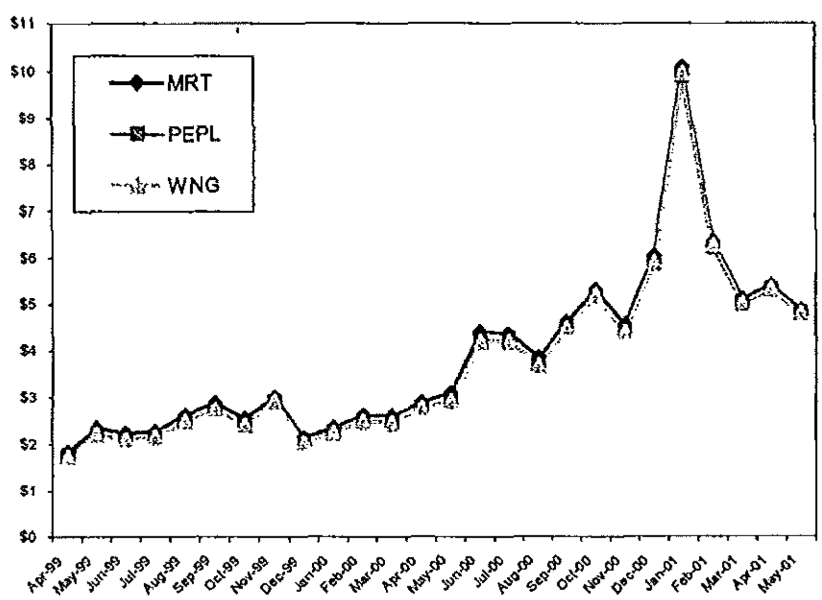
Missouri Supply and Demand Issues
Missouri does not have any natural gas production of significance. For all practical purposes, Missouri's natural gas demand is met through supplies transported to Missouri via interstate pipelines. Three major interstate pipeline companies, Mississippi River Transmission Corporation (MRT), Williams Gas Pipelines Central, Inc. (WNG) and Panhandle Eastern Pipe Line Company (PEPL), transport into Missouri the majority of natural gas consumed by the State.

The pipeline index prices (see Chart 5.9) of these three interstate natural gas carriers show the commodity cost incurred by LDCs for the portion of their supplies that are tied to the index prices associated with these pipelines. As Chart 5.9 shows, the indexes associated with these major pipelines do not vary significantly. In Missouri, interstate pipeline companies transport natural gas directly to most of our LDC's city-gates. The FERC regulates interstate pipelines. Some of our smaller LDCs and municipalities are served by intrastate natural gas pipelines that are regulated by the MoPSC.

The MoPSC approves all rates that LDCs charge their customers. This includes non-gas costs and gas costs. Non-gas costs are addressed in general rate cases where all factors associated with the LDC's costs of doing business, including a reasonable rate of return, are addressed. Gas costs are addressed through the PGA rate. The PGA includes commodity gas costs, transportation costs, and storage costs. The high-spiking index prices in Chart 5.9, which immediately impacted the state's LDCs this past winter, will eventually be paid by Missouri's natural gas consumers who were exposed to index based contracts. The price spike in Chart 5.9 coincides with the up-trend in national consumption/demand, shown in Chart 5.8 and the end of the coldest combined 2 months in Missouri's history.

The EIA notes that the rapid run-up in prices last winter actually started in the summer of 2000 when electric generation demands caused by above average temperatures kept demand high while market participants delayed some gas purchases while waiting for the market price to drop. Continued electrical generation demand, storage demand, and market concerns kept summer prices above normal and contributed to a rapid price spike when much colder than normal weather arrived in November of 2000 and continued for 2 months.

Chart 5.9 - First of Month Pipeline Index Prices for MRT, PEPL, and WNG



The strong economy of the 1990s steadily increased the demand for electricity, but little new development in electric power generation occurred to meet this growth. Instead, operating margins between electrical supplies vs. anticipated peaks were slowly eroded. Environmental issues, market uncertainties, public opinion, and associated construction cost were, at different levels, all barriers for electric utility companies to construct large generating facilities, i.e., coal-fired or nuclear plants. Alternatively, in recent years, construction of electric generation facilities using gas-fired turbines, which can be installed and fully operable in as little as 18 months, has risen in efforts to satisfy national peak and even, to some degree, base electrical demands. The abundance, clean-burning properties, and relatively low price of natural gas made it an environmentally favorable fuel source for these turbine engines, and therefore dramatically contributed to the popularity of, and demand for, natural gas. Many of these single and combined cycle combustion turbine plants are built by unregulated entities to sell electricity on the open market.

As of May 2001, eleven new electric generating plants in Missouri have been announced with eight already under construction. In fact, the Aries plant near Kansas City recently went online. When all are online, their generating capacity could total to approximately 5,000 additional MW. Out of the eleven plants, ten will utilize natural gas as a major fuel source, which will further increase Missouri's future need for natural gas. Environmental, siting, and construction costs and schedule issues will likely continue to result in a large percentage of new electrical generation coming from natural gas.

U.S. Working Gas Storage Levels

Relatively low U.S. working gas storage levels prior to entering the 2000-01 winter also contributed to the increase in natural gas commodity prices since this helped drive up mid-winter demand. Demand for electric generation for the year 2000 cooling season (April – October), helped sustain natural gas prices above recent year's averages. At this same time, purchases of natural gas were made to replenish working gas storage levels used to hedge against generally higher winter natural gas prices. Spring 2000 U.S. gas storage levels, shown in Chart 5.10, had fallen to average levels ❶ following the previous moderate winter. Natural gas utilities and other market participants slowly replenished their gas storage resources, anticipating prices would flatten or decrease from their unusually high levels. Natural gas prices contrastingly continued to rise and total U.S. working gas storage levels ❷, levels maintained prior to winter heating months, were filled to near a five-year low.

The estimated total U.S. Working Gas Storage Capacity is 3,248 Bcf, and year 2000 storage levels peaked at an estimated 2,748 Bcf, or approximately 85 percent of estimated total capacity. In the previous five years, the highest estimated storage capacity occurred in 1998 at approximately 3,094 Bcf ❸, or 95 percent of capacity. Although easily overshadowed by the annual national commodity consumption rate of 20-plus trillion cubic feet, working natural gas storage plays a critical role in hedging against price spikes and must not be overlooked. The American Gas Association (AGA) estimates natural gas storage accounts for about 20 percent, on average, of the commodity's consumption during the winter heating season. Beyond just displacing gas needs that would be met by purchases from the wellhead in the winter, storage also plays a critical role in daily balancing requirements for a number of our LDCs.

Over 85 percent of Missouri's residential natural gas consumers are served by four investor-owned LDCs, each utilizing gas storage in gas supply portfolios. Gas storage plays an important role as a hedging tool for Missouri's LDCs attempting to mitigate market volatility and achieve some price stabilization. Laclede Gas Company, Missouri's largest LDC with over 600,000 customers, owns and operates over 6,000 MMcf of Missouri's in-state 7,800 MMcf total working gas storage. Most storage gas supplies purchased by our LDC's are stored outside of Missouri under firm contracts with interstate pipelines.

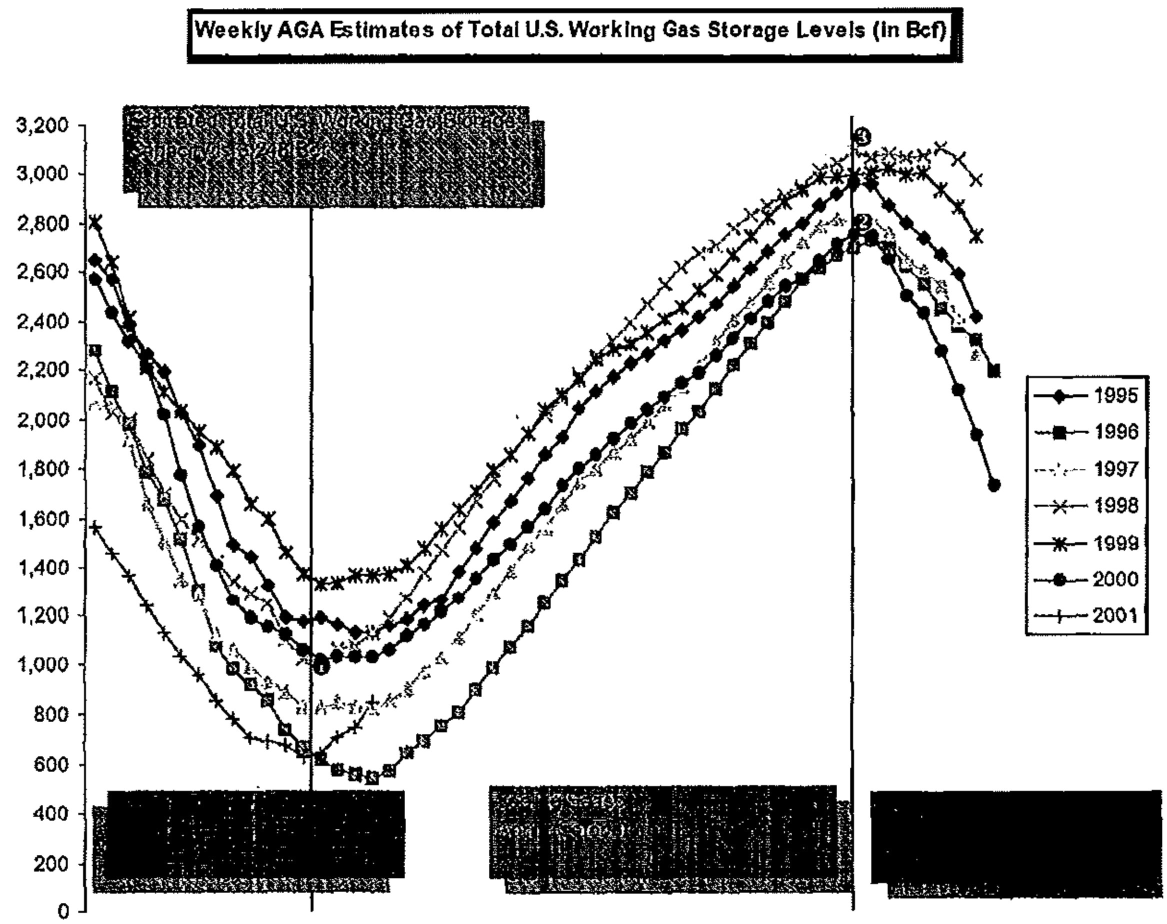


Chart 5.10 - Estimated Average Storage of Natural Gas

Weather Conditions

Abnormally warm summer months in the year 2000 cooling season helped keep natural gas prices higher than customary and played a significant part in pre-winter working gas storage levels being filled to near a five-year low. Record cold weather conditions in November and December 2000 only worsened matters, converging with low storage, increased demand and already high natural gas prices to create a dramatic spike in natural gas heating bills.

Comparing an average Missouri residential consumer's 1999 and 2000 winter heating usage of natural gas signifies last winter's record cold average temperatures affect on consumption, especially in November and December 2000. November 2000 average usage per consumer (136 Ccf) increased 74% from November 1999's comparable average consumption (78 Ccf). In other words, considering only increased consumption resulting from the record cold winter and holding November 2000 natural gas prices at the November 1999 price of approximately $3.89/Mcf, the end-consumers' heating bill dollars (before taxes) just for natural gas increased from $30.34 to $52.88, on average. Factoring both increased quantities and higher prices into heating bill dollars, the average Missouri residential consumer paid 142% and 116% more for natural gas used during November and December 2000 than during the same period in 1999, respectively.

This double impact of greater wholesale natural gas prices and greater consumption laid a heavy burden on natural gas consumers' budgets during the 2000-01 winter. Last winter's experiences have broadened natural gas consumers' perspectives on topics such as price stabilization, deregulation, and energy conservation, but the market's volatility and the unpredictability of the weather still leaves many uncertain of what's to come in 2001-02 winter.

5.e) Gas Supply Contracts and Index Pricing

One of the key provisions in every natural gas supply contract is the pricing provision. There are many different types of pricing provisions that may appear in natural gas contracts. Of all the numerous variations, many fit under two broad categories: fixed price and formula/indexed-based price.

A fixed price means that the absolute price that will be paid is already known and directly stated in the contract. An index price may reference an outside publication that independently calculates the price at some point in the future.

Index pricing grew in popularity in the 1980s with the emergence of a spot market for natural gas. Independent industry newsletters base the calculations upon actual gas supply deals for the applicable period. In a typical situation, the index is based upon a period of time know as "bid-week". This is the week prior to the delivery month where gas supply deals are finalized and nomination deadlines on the pipelines are met. Pricing points are usually in the production area at the beginning of an interstate pipeline's mainline system. Weighted averages are derived from a sample of the deals that are conducted at these various pricing points. The prices developed are for deals of 30 days or less and are known as "first-of-the-month indexes". Formula/indexed-based price contracts often refer to one of, or an average of several of, these indexes for each month's per unit pricing.

Examples of these market publications include: Inside FERC Gas Market Report, Natural Gas Intelligence Report, Gas Daily, etc. Methodologies are described at the following websites:
http://www.platts.com/gas/specification.shtml
http://www.intelligencepress.com/methodology.html
http://www.ftenergyusa.com/gasdaily/gdguide.asp

According to an AGA Report titled "LDC System Operations and Supply Portfolio Management During the 1999-00 Winter Heating Season":

"Many LDCs continue to price gas based on numerous indexes during the winter heating season. In fact some LDCs refer to their pricing strategies as a basket of indices. Of the LDCs that purchased mid-term supplies during the 1999-00 winter, the majority (92 percent) used first-of-the-month pricing for at least a portion of their gas purchases."

The study further indicated that at least 75% of winter heating "mid-term" supplies were based on a first-of-the-month index.

Index pricing is often considered to be market based since it tracks current market conditions. Indexes are not known until very close to the time period they relate to. In other words, if a contract referred to a "first-of-the-month index" for December, the price of gas for that month would not be known until December 1. Index pricing can be volatile, as first-of-the-month indexes have varied between $1 and $10/MMBtu over the last decade. In the span of 2 months last winter certain indexes moved from $4.50 to $10/MMBtu.

Pricing of natural gas futures contracts on the NYMEX is now widely monitored for gas price data. These prices are tied to a particular delivery location, the Henry Hub in Louisiana. Henry Hub is a major interconnect for several pipelines with connections to many demand centers. Index prices vary from NYMEX pricing due to location differences and other factors but have historically moved in the same general pattern as movements in the futures markets at expiration of a particular delivery month. Basis differences can be defined as the difference between the closing NYMEX prices and the cash price (index price) at a specified location.

Indexes have been used as benchmarks for the incentive plans of Missouri's two largest LDCs. For MGE the benchmark was in place for three winters starting with the winter of 1996-97. For Laclede the benchmark was also effective with the winter of 1996-97 and was still in place last winter.

It is the task force's understanding that Missouri's LDCs generally made use of storage resources during the year 2000 and the winter of 2000-01 as they have in years past. The task force was not made aware of any significant changes in LDC's use of storage. Therefore due to the summer-winter pricing differential during the year 2000 and the winter of 2000-01, storage gas constituted a physical hedge for gas supply costs (and also provided reliability assurances) for those LDCs with storage resources.

The task force was made aware that although the Commission had approved the use of financial instruments for hedging purposes under certain conditions for certain LDCs prior to the winter of 2000-01, and certain LDCs had undertaken financial hedging activities prior to and during the winter of 2000-01, neither the State of Missouri nor the Commission had any formal policy of broad applicability in place regarding the use of financial instruments for gas supply cost hedging purposes prior to the winter of 2000-01 beyond the application of the prudence standard. This standard was further clarified in the Commission's October 26, 2000 Order Denying Application to Renew Price Stabilization Fund and Rejecting Tariff in Case No. GO-2001-215, which states:

> *Staff is correct when it states that MGE should apply reasonable purchasing practices based upon its own evaluation of risks in its gas supply portfolio. MGE's business decisions will be subject to prudence review as are MGE's other gas supply choices.*

5.f) What Can We Expect Next Winter & Beyond

Higher than long-term average natural gas prices and volatility continue to be the reported forecast by industry analysts with near-term predictions being heavily weather-driven. Summer heat is a primary driver for natural gas demand for electrical generation and winter cold is a primary driver for space heating demand for natural gas. Several forecasts in January 2001, when wholesale prices spiked at over $10/MMBtu, cautiously predicted lower natural gas prices to come, which has been the current trend, but expectations of returning to January 2000 prices ($2.00 to $2.50/MMBtu) were very low. July 2001 prices ranging near $3/MMBtu, around 27 percent below prices paid at the same time in 2000, have had a major influence on gas storage. For over 3 months, the AGA has been reporting record national storage injections each week. This will likely help stabilize prices to consumers during 2001-02 winter. Generally speaking, natural gas prices for the 2001-02 winter are not expected to return to the low prices of 1998 or 1999 or reach the high prices of the 2000-01 winter.

The EIA continues to note that several factors will play key roles in where natural gas prices go in the future. These factors include opening currently protected areas for gas exploration and production (like ANWR, Rocky Mountains, east Gulf of Mexico, Atlantic coast, etc...); emission permits availability and costs (driving electrical growth toward natural gas fueled combustion turbines); delivery pipeline expansions into Canada and/or Mexico; Liquefied Natural Gas (LNG) terminal expansions; and others. Economic factors associated with a recession would also impact these projections. These same EIA forecasts indicate that the market may have a new average of about $3.50/Mcf. This price level seems consistent with a number of outcomes associated with pipeline expansions into Canada and/or LNG terminal expansions. At least in the near term, an average of about $3.50/Mcf is recognized to be a rough guess, but subject to a number of factors that will result in the market being lower than this price at times and much higher than this price at other times.

Significant concerns are currently being expressed regarding EIA estimates. These concerns include beliefs that the EIA's supply forecast is too optimistic. Recent reports on high rig counts and continuing sluggish growth in supplies despite this extraordinary exploration and production effort are pointing to an issue that will continue to be of great concern to those interest in natural gas supplies and prices. Even if $3.50/Mcf is accepted as a near term average, it is anticipated that well before 2020, as available reserves are smaller, more difficult to develop, and harder to transport to demand centers, prices will steadily rise.

Economic Factors

The implications of last winter's high natural gas prices on household incomes and large energy-consumer budgets are not completely known at this time, but obviously reduced consumer's disposable income and may have contributed to a slumping economy. The U.S. is currently in an economically uncertain period and this uncertainty contributes to a broad forecast range for natural gas prices. Both electric and natural gas project announcements have risen in light of the current emphasis on potential blackouts and a widespread energy crisis, but how many of these projects will actually reach operation remains to be seen. Higher average natural gas prices in the future cast some uncertainty on the prudence of total reliance on natural gas fueled electrical generation and other sources of electrical generation must continue to be part of every utility's planning effort to meet the needs of its customers. On the other hand, future higher average natural gas prices will be a powerful incentive for further exploration and production of natural gas, which will tend to help moderate prices. In the near-term, lower market prices could limit investment to fund high-capital natural gas projects. Also, low economic growth could create uncertainty about actual demand. If these factors are significant, they could lead to postponements of projects. Overall though, industry reports anticipate slow project development into 2002, but picking up thereafter to reflect forecasted growth.

Long-term economic growth is projected to increase natural gas demand and in turn increase future average wellhead natural gas prices; by how much will vary. The EIA reports projected wellhead prices to increase on average between 1.2 and 2.8 percent per year for the next 20 years under low and high economic growth scenarios, respectively. Discovery efforts and production operations will directly affect this upward trend in prices but technological advances and cost-savings in these areas will hopefully suppress dramatic long-term price spikes. Generally speaking, increased costs will likely be reflected in a gradual long-term increase of average end-consumer costs for natural gas, given current and rising future demand.

Electrical Generation

There is a growing inter-dependency between the gas and electric industries. Electric generation is projected to grow in the short-term and long-term projections remain optimistic about continued market growth. Natural gas consumption for electric generation in 2000 was less than half the amount of the industrial sector, the current leader in natural gas consumption. However, electric generation is projected to lead all sectors in natural gas consumption within 15 to 17 years. Growth in projected total domestic consumption of natural gas, therefore, will be greatly influenced and lead by electric energy demands in the western, particularly the California market, and eastern regions.

Comparably lower initial set-up costs, environmental advantages, shorter ground-breaking-to-operational time periods, and significant efficiency improvements have popularized the use of gas-fired turbines and combined-cycle facilities for electric generation in both the regulated and non-regulated sides of the electric industry. The current advantages of natural gas have heavily influenced the use of these generation facilities to meet growth in electrical demand. Until newer pipeline facilities are built, increased use of natural gas for electric generation may place utilization levels on existing facilities that have never been experienced before. If forecasted growth materializes, additional pipelines will be necessary or capacity constraints, bottlenecks, and end-consumer supply shortages may become a real possibility.

Missourians are seeing first hand the Nation's emphasis on energy production growth. As noted earlier, ten electric generation plants utilizing natural gas as a major fuel source have been announced, with some nearing construction, while others are already operating. Depending on plant locations, pipeline expansions may be required to deliver services with adequate capacity. This capacity will be essential as a large electric generation facility can require a level of natural gas capacity equivalent to a city the size of Columbia at peak load.

As a non-gas-production state, Missouri relies on interstate pipelines for delivery of natural gas from gas production states such as Texas, Oklahoma, Louisiana, and Kansas. Production excess in the Central Region has been reported but exporting pipeline capacity has limited the availability of the commodity to end-consumer markets. Other states, like Missouri, will also be bidding for these gas supplies to serve their increasing electric generation needs and dependency upon current natural gas pipeline capacities could become even more strained unless expansions develop. A number of potential expansion projects are currently being looked at by different interstate pipelines, and the Staff of the MoPSC will continue to watch these projects with great interest. It is essential that Missouri's LDCs continue to regularly assess their projected peak demands and determine which expansions they must participate in to meet the needs of their customers.

Natural Gas Storage

As noted earlier, commodity price drops through July 2001 have led to heavy volume purchases of natural gas during this year's storage injection season and reflect an inverted market from the same time last year when prices were on the rise. As of mid 2001 working gas storage totals trailed only 1998 and 1999 storage totals for the same given time periods, when comparing the past six-year averages. The volumetric rate of gas injections during the 2001 injection season, however, exceeds both 1998 and 1999.

Sluggish economic growth and mild summer-weather energy demand have contributed to the market's downward trend and have provided better than expected buying opportunities for replenishing storage levels. Although unpredictable weather-related-demands can allure market volatility, a continuation of the current market through the end of the injection season will hopefully play a major role in stabilizing end-consumer natural gas costs during the 2001-02 winter.

Increased Natural Gas Imports

To balance the nation's natural gas consumption dependency with domestic production, commodity imports from Canada and Mexico are expected to grow. The EIA reports "net natural gas imports are expected to grow ... from 15.8 percent of total gas consumption in 1999 to 16.7 percent in 2020." Availability of imports is expected to add to the supply factor, especially in the eastern region of the United States, but insufficient pipeline facility development could be a constraint to expanding markets in need. Sufficient pipeline capacity will be a key component for imports to keep pace with expected national demand and bringing to the energy-fuel market a supply level that's effective to moderate prices. Increased imports into the western and eastern regions add gas supplies that ultimately can aid in minimizing nation-wide commodity price spikes.

6. How Missouri Compared to Other Parts of the Country – PGA Rates &Typical Heating Bills

Last winter's rise in natural gas prices in Missouri was a reflection of market variables that affected the price of energy nationwide. The increase in natural gas prices that occurred over the 2000-01 winter was the result of several critical factors within the industry. The wellhead price of natural gas is a deregulated commodity and largely driven by supply and demand. The supply situation involved relatively flat growth in supplies since about 1995 with storage levels, at the beginning of the winter, that were somewhat below average. Relatively low demand and prices in the natural gas market did not make it attractive for exploration and production in the years immediately preceding the 2000-01 winter. The demand situation included extraordinarily cold winter weather throughout a large part of the US, a significant growth in demand for natural gas for electrical generation, and higher than normal demand for residential, commercial and industrial customers. Market speculation on natural gas prices may have also played a role. These factors combined to create a "seller's market" by mid-winter as prices climbed to near $10/MMBtu in late December and early January of the 2000-01 winter. It should be noted that national supplies for natural gas were not the problem, the EIA continues to indicate that domestic proven and speculated reserves of natural gas will meet most of our needs for several more decades. If international supplies transported as LNG are included, reserves may well last for over a century. The price spikes of the 2000-01 winter were more closely associated with tightness of supply deliverability to demand centers than natural gas reserves. Pipeline constraints presented significant challenges in some parts of the country. Missouri was not significantly impacted by pipeline constraints but areas like California were impacted by transmission constraints. During a number of market price jumps in the 2000-01 winter the Southern California market exceeded $50/MMBtu when Henry Hub was near $10/MMBtu. Some of this difference was due to transmission constraints on the El Paso line. A number of investigations are ongoing regarding this difference in pricing.

While nationally 53% of U.S. households use natural gas for heating, it is estimated that 60% of Missouri households utilize natural gas as their primary heating source (1990 census data). In an effort to examine how Missouri residential customers fared this past winter regarding natural gas prices in comparison to other Midwest states, a survey of neighboring states regulating natural gas was performed. The results of this review are shown in Table 6.1. Findings indicate that while Missouri residents experienced similar spikes in natural gas prices as the rest of the country, prices in mid-winter were not as elevated as in some other areas of the Midwest. In comparing the prices for Missouri's two largest LDCs to LDCs in other states, average prices effective January 1, 2001 were less than most other states surveyed. Although this comparison is of interest, it must be noted that estimated January 2001 natural gas bills cannot necessarily be directly compared to Missouri's natural gas bills as usage calculated in the monthly billing varies from state to state due to geographic location and temperatures experienced. Also, some of the observed differences in rates are the result of differences in when PGA rates can change and how much under recovery in gas costs the noted LDCs were willing to accept before filing for changes in rates.

Table 6.1, Comparison of Midwest Regulated PGAs and Bills				
State	LDC & Effective Rate on 1/1/01 ($s/Mcf)		Average	Estimated Jan. 2001 Bill
Arkansas	Arkla	$7.60	$5.60	$143
	AWG	$3.59		$100
Illinois	Peoples Gas	$9.77	$9.64	$327
	NIGas	$9.50		
Iowa	Mid-American	$10.51	$10.00	$224
	IES	$9.49		$206
Kansas	Kansas Gas Service	$8.68	$8.68	$178
Kentucky	Louisville G & E	$6.44	$7.28	$147
	Columbia Gas	$7.67		$209
	Western Ky Gas	$7.74		$163
Missouri	Laclede Gas Company	$6.45	$6.63	$200
	Missouri Gas Energy	$6.80		$196
Oklahoma	Oklahoma Natural Gas $7.89	$7.89	$7.89	$192
South Dakota	MidAmerican Energy	$10.50	$8.65	$247
	Montana - Dakota Util.	$6.80		$171
Tennessee	Nashville Gas	$7.03	$7.17	$229
	United Cities Gas	$7.31		

A number of other reasons may have also contributed to these differences in rates between states. In fact, significant differences in rates exist between different LDCs within the state of Missouri. These differences can include, but are not limited to a) overall system size and mix of the LDCs customer base, b) availability and use of storage capacity, c) how LDCs choose to participate in index priced, fixed priced, and transportation contracts, and d) the LDCs hedging strategies as well as the different percentages of supplies from these sources. Changes in PGA rates can also be a result of differences in regulatory practices in states and how much under or over recovery an LDC is able, and/or willing, to incur before requesting changes in rates. In comparing bills it is also necessary to recognize that distribution charges vary among different LDCs.

7. Other Options for Changing How Consumers Pay for Natural Gas Service

During the deliberations of the task force, groups briefly discussed a number of non-gas cost issues and options. The task force group as a whole did not deliberate on these "other" options because these other issues and options did not specifically deal with gas commodity costs, which were the focus of this task force. The task force group briefly discussed how to address these other issues and options and decided that they should be noted in the final report of the task force for the benefit of decision makers who may wish to consider options that were not considered by this task force. These "other" options were as follows:

- Reduce, cap or eliminate gross receipts taxes (GRT)
- Weather Normalization Adjustment Clause
- Base (margin) revenue distribution charge rate design revision

Each of these options and their associated pros and cons are noted in more detail below. It is important to note that utility and OPC interests were very different in this section. This resulted in a number of pro and con statements that one party or the other strongly disagreed with. In fact, some argued that this section should not be included in the task force report. No effort was made to resolve these differences in opinion, as this was not the focus of the task force. The summary statements and associated pros and cons below are the result of editing of comments received from utility, OPC, and other representatives by the chair of the task force and do not necessarily represent the opinions of Staff, the utilities, OPC, or others but do include most of the pro and con statements provided by interested parties.

Reduce, cap or eliminate gross receipts taxes
Description: Under this option, gross receipts taxes would be reduced or capped during the winter months. Alternately it could be converted to another form, such as a flat monthly $/customer charge, or eliminated entirely. To the extent that a viable option might be consumer choice of gas suppliers, GRT becomes a complicating factor. At least one state, Pennsylvania, has recently eliminated GRT on gas sales/distribution.

Pros

- Reduction to customer's total bill.
- If capped, a partial reduction of the bill will result from the portion of the bill that is not taxed.
- Could eliminate negative aspects of tax windfall to municipalities during colder than normal weather.
- Possible savings by LDCs of costs associated with processing GRT.

Cons

- Does not reduce the volatility of gas costs, only reduces the total bill by the amount of reduced taxes on the gas plus distribution charges.
- If GRT are eliminated, loss of revenue source to municipalities may force them to reduce services or make-up for the tax revenue loss through increases in other taxes. If capped, loss of tax windfall revenues during abnormally cold weather could result in less available funds for associated increases in snow removal, road salt, and increased municipal operating costs during colder than normal weather.
- The Commission lacks authority to reduce or cap GRT and this would need to be addressed by state and local governments.

Weather Normalization Adjustment Clause

Description: A Weather Normalization Adjustment clause allows a utility to true-up for weather, the recovery of non-gas distribution costs on an annual on-going basis. On a regular basis (usually with some lag or via deferral) a customer's bill is adjusted so that the revenue generated for base rate (margin) revenue is trued up to normal weather. Forty-four LDCs in 22 states have implemented them.

Pros

- Slight to moderate reduction in both the volatility and financial impact of weather variations upon the recovery of non-gas (distribution) costs for both consumers and LDCs.
- Identified by NARUC as an option that public service commissions "may want to consider".
- May decrease the frequency of rate case filings.
- Would have been beneficial, in terms of reduced natural gas bills, in the 2000-01 winter when there was a coincidental price spike for commodity gas at the same time as extremely cold weather. Would result in higher bills for consumers during warmer than normal winters with associated recovery of distribution costs by LDCs that they would not have received otherwise.
- Reduced weather risk for utility may bring about lower costs.

Cons

- Applicable to approximately 20 to 35 percent of total gas bill so potential impact on volatility of overall bill is limited.
- The MoPSC has previously rejected a weather adjustment clause, stating it was "single-issue ratemaking." See: In Re: Missouri Gas Energy GT-95-429 October 27, 1995.
- Customers will have a wide range of opinions on this type of methodology. Some will like it and others will not.
- Consumers may not benefit from any cost reductions associated with reduced weather risk to LDCs.
- Decreased incentive to conserve energy since charges on distribution costs would be adjusted based on actual weather. Price signal incentive for conservation from PGA portion of costs would still be in place.
- Customer education necessary to address confusion/questions on adjustment charges.

- Utility may incur one-time costs due to additional programming if billing system needs to be upgraded to accommodate changes.
- Obtaining uniformity in developing and applying a standardized weather measure may be difficult.

Base (margin) revenue distribution charge rate design revision

Description: Redesign of base rates for fixed (non-commodity related) distribution charges, placing more or all costs in the monthly service charge and less or none in the commodity charge. Carried to full implementation, such a rate design may be a full fixed variable design (like Georgia) or complete elimination of the commodity related portion for recovery of distribution costs so the service, or distribution charge, is a flat monthly fee considered as a system access fee. Under the access fee structure, rate class revenues are divided by annual number of bills and the customer pays that flat monthly fee each and every month. Distribution costs recovery is currently about 20 to 35 percent of a customer's average monthly bill for natural gas service.

Pros

- Less seasonal volatility of customer's bill (winter bill reductions of approximately $9 to $18/month with corresponding increases in summer bills, based on normal weather – lower when warmer, higher when colder).
- Distribution charge component of customer's bill is more predictable the closer the rate becomes to an access fee.
- Less risk and more stable revenue stream for utility with possible lower costs.
- Recommended as one of six areas to "review for possible long-term solutions" in Attorney General Jay Nixon's Report on natural gas price spikes to Governor Bob Holden, dated February 26, 2001.
- Some have argued (utility) that distribution costs do not vary significantly with customer usage but, rather, are based on the number of customers served, and should be recovered on a customer related access fee basis. Some have also argued that monthly service charges, or access fees, are commonly accepted in today's consumer market.

Cons

- Applicable to approximately 20 to 35 percent of total gas bill (non-gas or distribution portion) so potential impact on volatility of overall bill is limited.
- Slight to moderate reduction of price signal since the non-gas or distribution portion of the total natural gas bill may no longer be a function of the quantity consumed.
- Some have argued (OPC) that this type of rate design helps insulate the utility from (1) competition with electric utilities for space heating loads and (2) competition from distributed generation resources such as photovoltaics.
- Small users (in terms of consumption) may be subsidizing large users.
- Low load factor customers may be subsidizing high load factor customers.
- The utility has an incentive to add customers rather than load. Depending on line extension policy, this may be less beneficial to existing customers.

8. Appendices

Appendix A: Transcripts from Public Meetings

The transcripts from the task force's public meetings are available on the Internet at http://www.psc.state.mo.us/publications.asp under "Natural Gas" with the following titles:

Task Force April 26th Public Meeting Transcript
Task Force May 4th Public Meeting Transcript
Task Force May 10th Public Meeting Transcript
Task Force May 24th Public Meeting Transcript.

The task force's 5th and 6th public meetings, held in Sikeston and Joplin respectively, were not well attended and no transcripts were taken in these meetings.

Appendix B: Glossary of Natural Gas Industry Terms

ACA – Actual Cost Adjustment - The annual proceeding before the Missouri Public Service Commission in which a gas utility's actual gas costs are reconciled against the amounts it has collected from customers through its PGA charges during the year.

Base Gas – The portion of gas in a storage basin that is typically not considered for withdrawal, as it is important that some base gas be left in certain types of storage facilities for reliable operation of the storage basin.

Baseload contract – A gas supply contract that requires the buyer to purchase and receive a levelized volume of gas throughout a specified time period.

Benchmark – A standard against which a local distribution company's performance in utilizing its gas supply assets in meeting the requirements of its customers can be measured.

Bcf – Billion Cubic Feet – A unit of measure for large natural gas users or storage facilities.

Btu – British Thermal Unit - A measure of the heat content of natural gas. One cubic foot of natural gas is typically equivalent to about 1,000 Btu.

Capacity release – The sale and assignment of firm transportation capacity by a primary capacity holder such as a gas utility to a third party.

Call option - A financial instrument which permits the owner the right but not the obligation to purchase a specified quantity of gas at a specified strike price in a future period. It can be used to establish a ceiling price for natural gas purchasers but does require that the owner pay a price equivalent to an insurance premium to have the right.

Ccf – One hundred cubic feet, which is a standard measure of the quantity of natural gas. See also Mcf, therm, dekatherm, and MMBtu.

City gate – The point at which an interstate or intrastate delivery pipeline is interconnected to and delivers gas to the local distribution company.

Commodity charge – A per unit charge for gas purchased or transported during a month.

Contract Demand – The maximum amount of gas deliverable by a natural gas producer or pipeline to a utility, as specified by contract during any gas day, i.e. during any 24-hour period commencing at 9:00 a.m., prevailing Central Time.

Costless collar – A cost-free financial instrument which creates a ceiling price for a specified quantity of natural gas, in exchange for a floor price for the same quantity. It stabilizes the price for the specified quantity of gas between the floor and ceiling prices.

Dekatherm – Equivalent to one million Btu.

Demand charge – A fixed monthly charge to reserve and assure the availability of firm gas supplies. This charge does not vary based on the actual volume of gas purchased, within contract demand limits, during the month.

Demand Side Management (DSM) – A program typically designed to reduce natural gas usage (or electrical demand for an electric utility) as part of an effort to minimize need for growth in supplies (or electrical generation) with delivered costs objectives and/or to achieve particular energy efficiency goals.

FERC – Federal Energy Regulatory Commission, which is the federal agency charged with the responsibility of regulating the rates and terms of service for interstate natural gas pipelines.

Futures Contract - A supply contract between a buyer and seller, whereby the buyer is obligated to take delivery and the seller is obligated to provide delivery of a fixed amount of a commodity at a predetermined price at a specified location. Futures contracts are traded exclusively on regulated exchanges and are settled daily based on their current value in the marketplace.

Gas producers – Owners of gas producing wells and reserves who explore for, drill, develop, produce and sell gas at unregulated prices.

Gas storage – Underground reservoirs used to store natural gas for withdrawals in future periods. Typically used for daily and monthly balancing, seasonal load shaping, and price arbitrage. Can be constructed as underground salt domes in deep salt deposits or in aquifers with an impermeable dome rock structure or depleted oil and/or gas fields. Can also be stored as liquefied natural gas but this is much less common.

GSIP – Gas Supply Incentive Plan, which is a Missouri Public Service Commission-approved plan, whereby a gas utility is provided financial incentives to encourage it to devote additional resources to optimize the use of various gas supply options for its customers.

HDD – Heating Degree Day – A measure of the "coldness" of a given time period. Usually defined as the difference between the average temperature in a day and 65 degrees Fahrenheit. If a day had an average temperature of 25 F, the day could be referred to as having had 40 HDDs. Weekly, monthly, and annual HDD numbers are typically just the sum of the daily HDDs recorded in the period of interest.

Hedge – A mechanism which can be used to mitigate the volatility of gas prices, such as gas storage or the purchase of various financial instruments or fixed-price contracts.

Index Price – The daily or monthly price of natural gas in a particular location set forth in industry publications such as Gas Daily and Inside FERC.

Interstate pipeline – Any FERC-regulated pipeline that transports gas from production fields to local distribution companies and end users in different states.

LDC – Local Distribution Company - Is the local gas utility that distributes gas from the interstate or intrastate pipeline to end use consumers of natural gas. Rates and services of Missouri's regulated LDCs are regulated by the Missouri Public Service Commission.

Mcf – One thousand cubic feet, which is a standard measure of the quantity of natural gas. See also Ccf, therm, dekatherm, and MMBtu.

Missouri Public Service Commission – The State agency charged with the responsibility of regulating the rates and terms of service of the local regulated gas utility.

MMBtu – One Million Btu - Is a standard measure of the quantity of natural gas approximately equivalent to a Mcf. See also Ccf, therm, dekatherm, Mcf.

MMcf – One Million Cubic Feet – a common unit of measure for large customers.

Office of the Public Counsel – The State agency charged with the responsibility of representing consumers in proceedings before the Missouri Public Service Commission.

Off-system sales – The sale of gas by a gas utility to customers outside its service territory in Missouri.

Peak Design Day – The coldest possible day anticipated for a specified gas supply planning period.

PGA Clause – Purchased Gas Adjustment Clause, which is the provision in each local distribution company's tariff that permits it to recover gas supply, transportation and storage costs, on a dollar-for-dollar basis, from customers.

Pipeline discounts – Reductions in the maximum transportation or storage rates established by the FERC or the Missouri Public Service Commission negotiated between gas pipelines and their utility customers based upon competitive factors.

Put – A financial instrument that permits the seller to sell a specified quantity of gas at a specified price. It can be used to establish a floor price for natural gas sales.

Reservation charge – A fixed monthly charge to reserve firm pipeline transportation or storage capacity.

Strike price – The price at which a call option permits the owner to purchase gas.

Swing contract – A gas supply or transportation contract which permits the flexibility to purchase or transport amounts of gas between zero and a maximum amount specified in the contract.

Therm – Equivalent to 100,000 Btu. This is also approximately equivalent to 1 Ccf. See also Mcf, MMBtu and dekatherm.

Throughput – The amount of gas transported through specified facilities over a specified period of time.

WACOG – Weighted Average Cost of Gas, which is a method used to calculate an average price of a portfolio of gas supplies including the cost of gas inventory held in gas storage reservoirs.

Working Gas – The amount of natural gas in a storage basin that can be removed and replaced in each injection/withdrawal cycle.

Appendix C: List of Natural Gas Commodity Price Task Force Members

Natural Gas Commodity Price Task Force Members			
Name	**Organization**	**Name**	**Organization**
Robert J. Amdor	UtiliCorp United/Energy One	Jan Marcason	Mid-America Assistance Coalition
David Beier	Fidelity Natural Gas	Mary K. Matalone	Interested Consumer
Jim Browning	Palmyra City Mayor	Tim Maupin	Interested Consumer
Pat Childers	Atmos Energy Corporation	Rep. Carol Jean Mays	Representative - District 50
Stuart W. Conrad	Finnegan, Conrad & Peterson	Anne McGregor	MC^2 Consultants
Charles H. Day	Interested Consumer	Cathleen Meyer	City Utilities of Springfield
Mark Drazen	Drazen Consulting Group	Michael C. Pendergast	Laclede Gas Company
Jeremiah D. Finnegan	County of Jackson - Counsel	Anita C. Randolph	DNR Energy Center
Jim Fischer	Fischer & Dority, P.C.	Joseph Schulte	Gas Workers Union Local 5-6
Bill Guinther	Interested Consumer	Tim Schwarz	MOPSC
Robert J. Hack	Missouri Gas Energy	Amy Sheridan	
Martha S. Hogerty	Office of the Public Counsel	David Sommerer	MOPSC
Rep. Rod Jetton	Representative - District 156	Sen. Sarah Steelman	Senator - District 16
Chris Kaitson	Kansas Pipeline - Counsel	Rich L. Taylor	Interested Consumer
Robert E. Kindle	Interested Consumer	Diana M. Vuylsteke	MO Indust. Energy Consumers
Richard J. Kovach	Ameren Services	Vicki Walker	Interested Consumer
Charles D. Laderoute	Independent Consultant	Joyce White	Interested Consumer
Joyce Lucas	Interested Consumer	Gary W. Wood	Bethany Muni. Gas
		Warren Wood	MOPSC
Peope Who Attended on Behalf of Others or As Interested Parties:			
Tom Byrne	Ameren Corp.	Brenda Wilbers	DNR Energy Center
Scott Glaeser	Ameren Corp.	Lesa Jenkins	MOPSC
Phil Lock	MOPSC	Shawn Gillespie	UtiliCorp United Inc.
Mark Martin	Atmos Energy	Barbara Meisenheimer	Office of the Public Counsel
Doug Micheel	Office of the Public Counsel	Jim Busch	Office of the Public Counsel