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Report to Congressional Committees and Members of Congress

December 2002

NATURAL GAS

Analysis of Changes in Market Price

GAO

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GAO-03-46

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Highlights

Highlights of GAO-03-46, a report to congressional committees and members of Congress.

NATURAL GAS

Analysis of Changes in Market Price

Why GAO Did This Study

During the winter of 2000-2001, the wholesale price of natural gas peaked at a level four times greater than its usual level. Responding to the congressional interest and concern caused by these high prices, GAO undertook a study to address the (1) factors that influence natural gas price volatility and the high prices of 2000-2001; (2) federal government's role in ensuring that natural gas prices are determined in a competitive, informed marketplace; and (3) choices available to gas utility companies that want to mitigate the effects of price spikes on their residential customers. GAO surveyed a nationwide sample of gas utilities and staff of state utility regulatory agencies.

www.gao.gov/cgi-bin/getrpt?GAO-03-46.

To view the full report, including the scope and methodology, click on the link above. For more information, contact Jim Wells at (202) 512-3841.

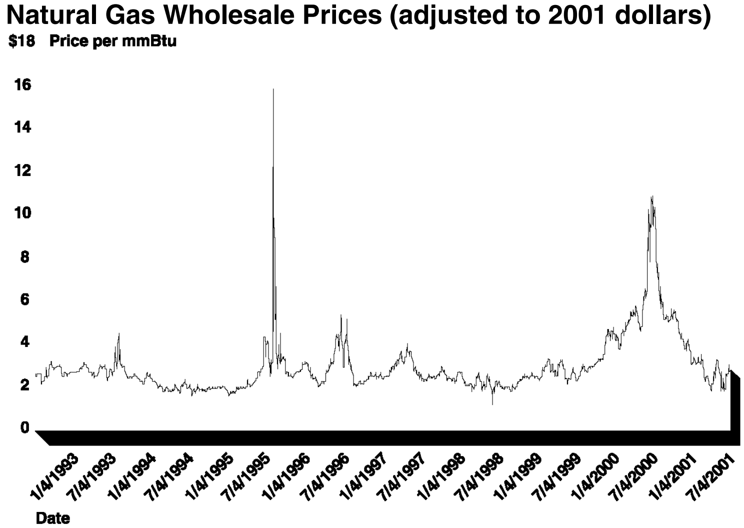
What GAO Found

Price spikes occur periodically in natural gas markets because supplies cannot quickly adjust to demand changes. In 2000-2001 for example, natural gas supplies were constrained and demand skyrocketed, leading to the perfect environment for the price spike shown below. While market forces make natural gas prices susceptible to price volatility, investigations are underway to determine if natural gas prices were manipulated in the Western United States during the winter of 2000-2001.

Federal agencies face major challenges in ensuring that natural gas prices are determined in a competitive and informed marketplace. The Federal Energy Regulatory Commission lacks an adequate regulatory and oversight approach and is reviewing its statutory authority and market monitoring tools. The Commodity Futures Trading Commission does not have regulatory authority for over-the-counter derivatives markets. It does have antimanipulation authority and is currently investigating what role, if any, these markets played in the natural gas price spike of 2000-2001. Finally, the Energy Information Administration has an outdated natural gas data collection program, but has made efforts to reassess its data needs to provide more useful information.

Gas utility companies can protect their residential customers against price spikes such as the one that occurred in 2000-2001. For example, using various hedging techniques, utilities can lock in prices for future gas purchases. Continuing volatility in natural gas prices, especially the price spike of 2000-2001, has increased the importance of price stability for gas utility companies. Agencies that commented on this report generally agreed with its conclusions.

Natural Gas Wholesale Prices (adjusted to 2001 dollars)



Source: GAO analysis of industry data.

Contents

Tables

Figures

Abbreviations:

AGA	American Gas Association
APGA	American Public Gas Association
bcf	billion cubic feet
CEA	Commodity Exchange Act
CFMA	Commodity Futures Modernization Act
CFTC	Commodity Futures Trading Commission
DOJ	Department of Justice
DRI	Data Resources, Incorporated
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
FTC	Federal Trade Commission
GU-H	Hypothetical gas utility
mmBtu	million British thermal units
NARUC	National Association of Regulatory Utility Commissioners
NYMEX	New York Mercantile Exchange
OMOI	Office of Market Oversight and Investigation
OTC	over-the-counter
SEC	Securities and Exchange Commission
tcf	trillion cubic feet

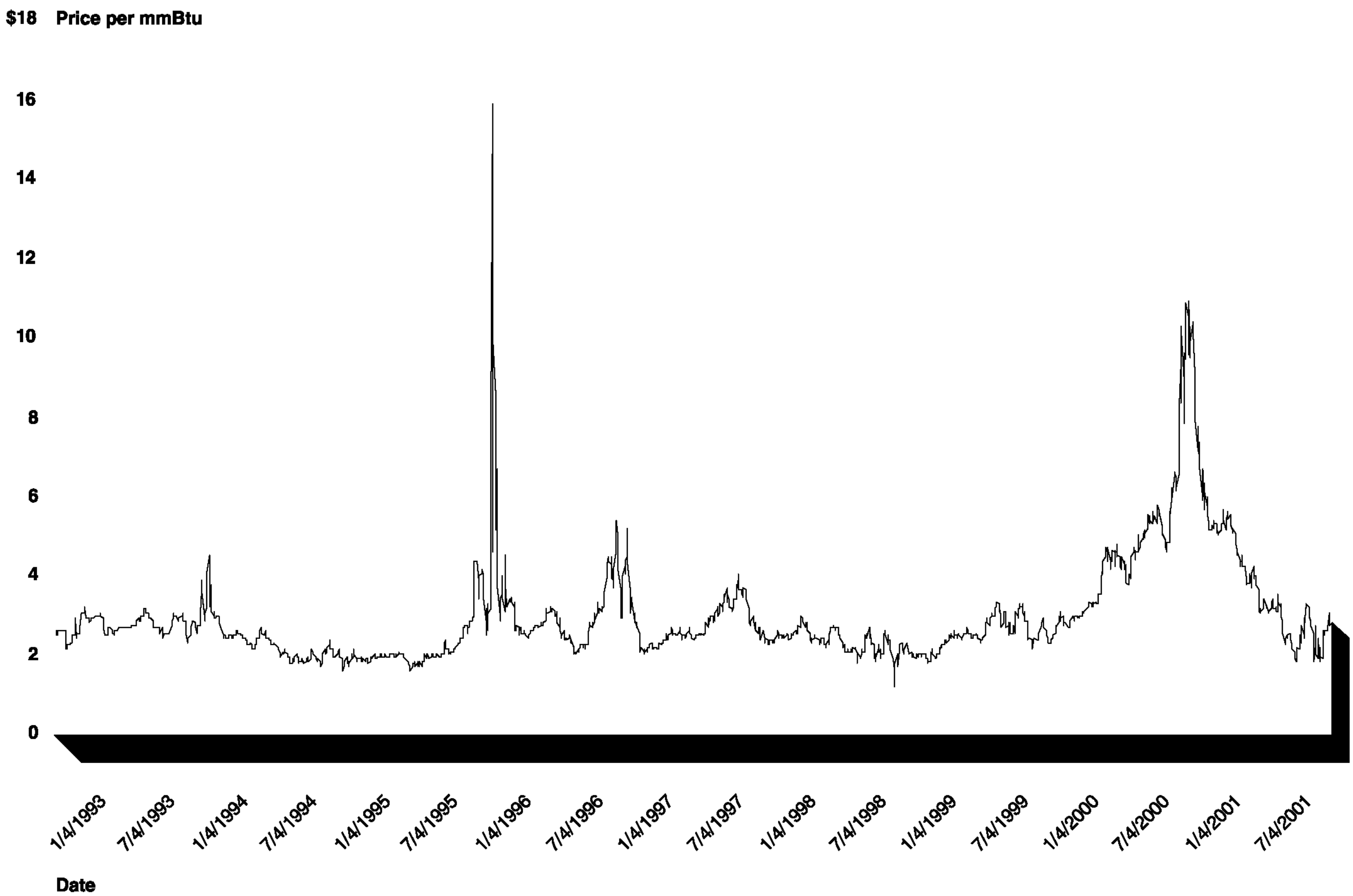
United States General Accounting Office
Washington, DC 20548

December 18, 2002

Congressional Committees and Members of Congress

Natural gas is an essential energy source in this country that has many applications, including heating more than 59 million homes and 5 million businesses, powering industrial and agricultural production, and generating a substantial amount of the nation's peak electricity needs. During the winter of 2000-2001, the wholesale price of natural gas peaked at a level almost four times greater than the average price since 1993. Figure 1 reflects this price spike in relation to natural gas prices over the period from 1993 through 2001.

Figure 1: Natural Gas Wholesale Prices Per mmBtu, Adjusted to 2001 Dollars



Source: GAO analysis of industry data.

Note: A million British thermal units (mmBtu) is a measure of energy content commonly used to quantify amounts of natural gas. It is approximately the equivalent of 1,000 cubic feet of gas.

One extraordinary aspect of this price spike was its prolonged duration, with prices remaining at high levels for a year. This period of high gas prices raised concerns among industry and government officials as to whether they would see the relatively low prices of the past any time in the near future. Although the 2000-2001 price spike was the longest experienced since federal wholesale price controls were removed in 1993, it did not mark the record high price for natural gas. This record high occurred on February 2, 1996, when the price was 46 percent higher than the peak price of the 2000-2001 winter.

The dramatic and prolonged price spike of 2000-2001, coupled with increased gas usage, affected all facets of the American economy. Millions of residential customers who purchase natural gas from local utility companies saw the costs of heating their homes increase significantly from the previous winter's costs. Nationwide, the average residential customer's total gas heating costs for the winter months increased from $380 to $624, and in some locations the increase was even greater. In addition, some companies significantly curtailed their production of products such as fertilizer because of the increased price.

Over the past 25 years, the wholesale natural gas supply market has evolved from a highly regulated market to a largely deregulated market, where prices are mainly driven by supply and demand. Before implementation of the Natural Gas Policy Act of 1978, which began deregulation of wholesale natural gas prices, the federal government controlled the prices that natural gas producers could charge for the gas they sold through interstate commerce. Under this regulatory approach, producers located natural gas reserves, drilled wells, gathered the gas, and sold it at federally controlled prices to interstate pipeline companies. After purchasing the natural gas, pipeline companies generally transported and sold the gas to local distribution or gas utility companies. These companies, under the oversight of state or local regulatory agencies, then sold and delivered the gas to their ultimate consumers, such as homeowners.

In today's deregulated market the federal government does not control the price of natural gas. Producers still locate and gather natural gas, but they now sell the gas at market-driven prices to a variety of companies, including marketers, broker/trader intermediaries, and a variety of consumers. Furthermore, the various players in the market may in turn sell gas back and forth several times before it is actually delivered to the ultimate consumers. In addition, several types of natural gas derivatives, which are contracts whose market value is derived from the price of the gas itself, can be bought and sold through numerous sources by entities that are interested in protecting themselves against increases in the price of natural gas. Derivatives markets—which include federally-regulated exchanges like the New York Mercantile Exchange (NYMEX) and off-exchange, over-the-counter (OTC) markets, which are generally not subject to federal regulatory oversight—become important because derivative prices typically move in parallel with the actual physical or cash market. These derivatives include natural gas futures and options.[1] Thus, there are a variety of different types of gas buying and selling arrangements that can be quite involved.

Overall, since the removal of federal price controls, the price of natural gas has decreased but yet has become more volatile. In one extreme example, the wholesale price of gas increased by 286 percent and then decreased by 71 percent over a 4-day trading period in 1996. A deregulated market also provides a new challenge to three key federal agencies that do not control the fundamental nature and operation of the natural gas market, but are charged with ensuring the existence of a competitive and informed natural gas market that is not subject to fraud or price manipulation. The Federal Energy Regulatory Commission (FERC) has responsibility for ensuring "just and reasonable rates" for the interstate transportation of natural gas, certain sales for resale of natural gas, and the wholesale price of electricity sold in interstate commerce. In addition, the Commodity Futures Trading Commission's (CFTC) mission includes fostering transparent, competitive, and financially sound commodity futures and options markets. Finally, the Energy Information Administration (EIA) is responsible for providing energy information that promotes sound policymaking, efficient markets, and public understanding. In addition to the challenges faced by these federal agencies, gas utility companies, operating under state or local regulatory bodies, are challenged in their efforts to mitigate the effects of price spikes on their customers.

In this context, this report addresses the (1) factors that influence natural gas price volatility and, in particular, the high prices that occurred during the winter of 2000–2001; (2) federal government's role in ensuring that natural gas prices are determined in a competitive and informed marketplace; and (3) choices available to gas utility companies that want to mitigate the effects of price spikes on their residential consumers. We are addressing this report to congressional committees of jurisdiction and to individual members that expressed concerns to us about natural gas price spikes. The complete list of addressees appears at the end of this letter.

[1]A futures contract is an agreement to buy or sell a commodity for delivery in the future at a price, or according to a pricing formula, that is determined at initiation of the contract. An obligation under a futures contract may be fulfilled without actual delivery of the commodity by, for example, an offsetting transaction or cash settlement. An option gives the buyer the right, but not the obligation, to buy or sell a commodity at a specific price on or before a specific date.

In addressing these issues, we examined government and industry price data to determine how and why natural gas prices have behaved since 1993, when federal wholesale price controls were removed. We also reviewed the oversight responsibilities of agencies and their efforts to monitor and collect information on the natural gas market. Finally, we surveyed a sample of gas utility companies to learn what actions these companies had taken or were planning to take to mitigate the effects of future spikes in the price of natural gas. The survey included 112 utilities that are members of the American Gas Association (AGA), which generally represents larger investor-owned gas utility companies, and 21 additional large utilities. These companies tend to have large customer bases, and collectively they distribute locally about 90 percent of the natural gas delivered by gas utilities in this country. The survey also included a sample of 342 of 906 smaller, municipally owned gas utilities that are represented by the American Public Gas Association (APGA). The municipally owned utilities generally serve fewer customers than the investor-owned companies. We received responses from 68 percent of the 133 larger utilities surveyed and 52 percent of the sampled smaller utilities. However, this response rate was not sufficient to generalize the results of our survey to all gas utility companies; therefore, we reported the results of only those that responded. In addition to the gas utility company survey, we also surveyed state regulatory agencies in the 48 contiguous states and the District of Colombia to determine how they oversee the purchasing and pricing of natural gas by the utility companies under their jurisdiction. We achieved a 100-percent response rate. A detailed description of our objectives, scope, and methodology is contained in appendix I. Appendixes II and III provide details on the gas utility companies' responses to our surveys. Appendix IV contains the state regulatory agency survey and appendix V provides details on the state regulatory agencies' responses to our survey.

Results in Brief

Price volatility is a natural condition of natural gas markets because natural gas supplies cannot quickly adjust to demand changes, leading to periodic supply and demand imbalances. In 2000-2001 for example, natural gas supplies, constrained by unusually low storage levels and the inability to quickly increase production levels, combined with skyrocketing demand associated with extremely cold weather and strong economic growth to create the perfect environment for the price spike that occurred. The lack of timely and accurate data about the overall natural gas market adds to the uncertainty about supply and demand conditions, further exacerbating price volatility. While market forces make natural gas prices inherently susceptible to volatility, there are some indications that natural gas prices may have also been manipulated in the Western part of the country during the winter of 2000-2001. A number of investigations are underway aimed at determining whether such manipulation occurred and until they are complete, it is not possible to definitely establish whether and how much prices paid by consumers were affected.

The federal government faces major challenges in meeting its role to ensure that natural gas prices are the result of supply and demand factors in a competitive and informed marketplace. As we have recently reported, FERC—the agency responsible for ensuring wholesale natural gas prices, sold and transported through interstate commerce, are just and reasonable—lacks an adequate regulatory and oversight approach to meet this role. FERC is still using legal authorities to regulate an evolving, competitive market that were enacted when the wholesale natural gas supply market was regulated. In addition, FERC's market oversight initiatives have been ineffective, serving more to educate staff about new markets than to produce effective oversight. As a result, FERC has been slow to react to charges of possible market manipulation and lacks assurances that wholesale natural gas prices are just and reasonable. FERC recognizes that it previously lacked an adequate regulatory and oversight approach and is reviewing its statutory authority and market monitoring tools. Recently, FERC has taken positive steps by creating a new monitoring office to better understand energy markets. In addition, CTFC—the federal agency responsible for fostering competitive commodity futures markets—does not have general regulatory authority over trading in the OTC derivatives markets. CFTC does have antimanipulation authority and is currently investigating what role, if any, that these markets may have played in the natural gas price spike of 2000-2001. These investigations could lead to enforcement actions or highlight the need for legislative changes. Finally, EIA—the agency responsible for providing energy information that promotes efficient natural gas markets and public understanding—has an outdated natural gas data collection program. Most elements of EIA's current natural gas collection program have been in place for more than 20 years, when the more regulated natural gas market was much less competitive and complicated. As a result, EIA's ability to provide information that promotes understanding of the market price of natural gas has declined significantly. EIA recognizes this limitation and has made efforts to reassess its information needs to provide more useful market information.

Although the price of natural gas is volatile and significant price spikes can occur, gas utility companies have various means of protecting their residential customers against price spikes such as the one that occurred in

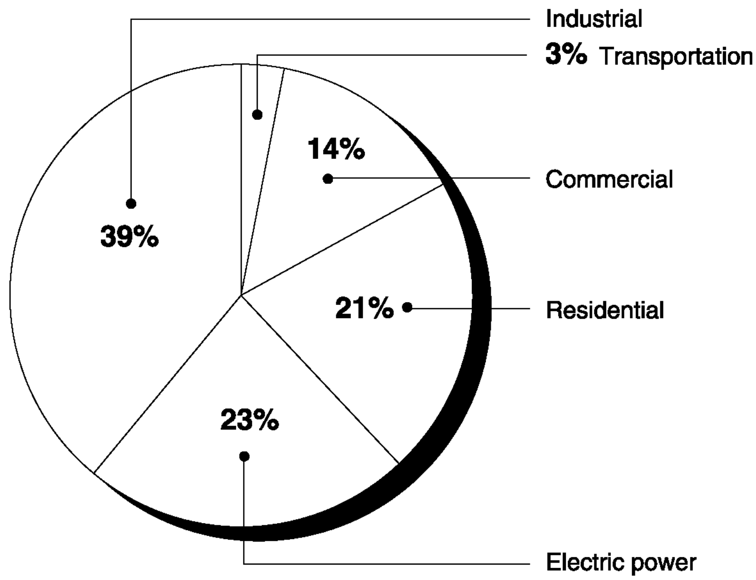
2000-2001. For example, through storage, fixed-price buying arrangements, and derivatives, utilities can hedge against the risk of price spikes by locking in prices for future gas purchases. The goal of hedging is to ensure stable prices, which are not necessarily the lowest possible prices: stable prices locked in for the future may be lower or higher than future market prices. However, continued volatility in market prices, most recently with the price spike of 2000-2001, has increased the importance of price stability for gas utility companies that serve residential customers and the state regulatory agencies that oversee this service. As a result, gas utility companies have increased their use of hedging. For example, 20 percent of the large and 32 percent of the small gas utilities responding to our survey reported that before the price spike of 2000-2001 they had not planned to hedge any of their gas supply. Consequently, their customers had to pay the prevailing market prices. In contrast, 90 percent of all the utility companies responding to our survey reported that they had decided to hedge some portion of their gas supply before the next winter (2001-2002).

This report does not contain any recommendations. However, in our recent report discussing FERC's oversight of new energy markets, we did make a number of recommendations to FERC on ways to improve its oversight of competitive energy markets. We also suggested that the Congress might want to review FERC's legal authorities to determine whether revisions are needed to respond to the changing competitive energy markets.

Background

Natural gas is a crucial source of energy in the United States. It is used in five sectors: residential, commercial, industrial, electric generation, and transportation. The United States used about 23.5 trillion cubic feet (tcf) of natural gas in 2000. Figure 2 shows the percentages of total gas usage by each of the five sectors.

Figure 2: U.S. Natural Gas Usage by Sectors, 2000



Source: GAO analysis of EIA's data.

EIA expects the country's consumption of natural gas will increase to 33.8 tcf per year by 2020. More than half of this increase is predicted to come from gas-fired electric generation. Eighty-four percent of the natural gas used in the United States is produced domestically, 15 percent comes from Canada, and about 1 percent comes from other countries. Almost 8,000 companies produce natural gas from wells located in 37 states and offshore. The producing companies range in size from small, family-owned businesses to large international corporations. According to the Independent Petroleum Association of America, small companies, most of which employ fewer than 20 people, produced 65 percent of the natural gas consumed by Americans in 2001.

Over the years, the natural gas market has undergone major changes, and it is still growing and evolving. However, perhaps the most significant change in the gas market—the transition from a regulated to a competitive natural gas market—has already occurred. Under the regulated market, producers sold their gas directly to interstate pipeline companies at prices set by federal regulation. Although this system ensured stable prices, it also caused severe gas supply shortages. These shortages occurred because, with artificially low prices, producers had no incentive to increase production and consumers had no reason to curtail their demand.

Ultimately, the gas shortages led to delivery curtailments during cold winters for many customers in the northern United States.

Responding to these supply problems, the Congress passed the Natural Gas Policy Act of 1978,[2] which began the phased deregulation of natural gas producer prices. This act established a pricing arrangement that encouraged increased production of natural gas, but producer price deregulation was not completed until after passage of the Natural Gas Wellhead Decontrol Act of 1989. This act mandated that federal controls over natural gas wholesale prices end by 1993, allowing the price to be set freely in the marketplace. In addition, FERC issued a series of orders during the 1980s and early 1990s to address the inability of natural gas users to gain access through the pipeline systems to competitive natural gas suppliers. The two most notable were Order 436 and Order 636. Order 436, issued in 1985, instituted open-access, nondiscriminatory pipeline transportation. In 1992, Order 636 was issued requiring pipeline companies to completely separate or "unbundle" their transportation, storage, and sales services. As a result, natural gas as a commodity was separated from gas transportation. Pipeline companies were required to treat other parties wishing to use the pipeline to transport natural gas the same as they would their own affiliated sales services. These laws and regulatory changes led to the competitive and more complex natural gas market that exists today.

In today's market, instead of selling natural gas strictly to the pipeline companies, producers now sell their gas to a variety of purchasers located across the United States. With the removal of federal price controls, producers' prices are determined in the marketplace. Natural gas is bought and sold at many different locations, to numerous parties, and under different sales and transportation arrangements. Numerous entities, including utilities and marketers, can buy, sell, re-buy and re-sell gas in a variety of ways.

The prices paid for natural gas can vary among the different buying arrangements. For example, before deregulation, many gas utilities' supply contracts were long-term—often for 20 years or more—with little variability in price. As deregulation unfolded in the 1980s, gas utilities attempted to obtain better gas prices for their customers by developing a portfolio of long-term and short-term supply contracts and purchasing

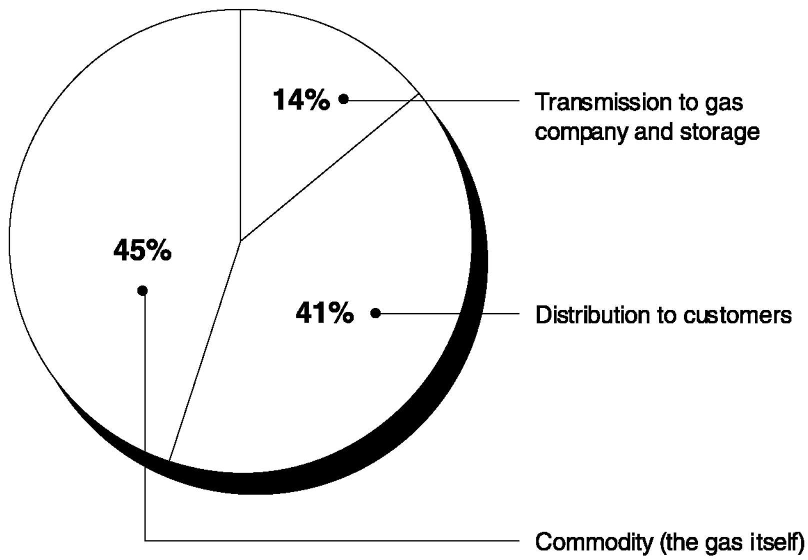
[2] P.L. No. 101-60 (1978).

some gas on the spot market.[3] However, while generally lower on average than previously regulated prices, the prices for short-term gas supply contracts and purchases on the spot market can be highly volatile. As shown in figure 1, several prices spikes occurred over the 9-year period ending in 2001, but with one exception, during 2000-2001, the price of natural gas quickly returned to previous levels.

Natural gas prices also vary depending on location because of the importance of factors such as proximity to gas production, pipeline capacity, and local supply and demand conditions. In addition, prices vary depending upon the step in the natural gas distribution process during which the gas is sold. Wholesale natural gas prices reflect the basic costs for the commodity itself and are reported daily at a number of production market centers throughout the country. Unless otherwise specified, the wholesale prices cited in this report are for gas at the Henry Hub, a natural gas market center located in Louisiana. The Henry Hub is one of the largest gas market centers in the United States and often serves as a benchmark for wholesale natural gas prices across the country. City gate prices are the prices at which gas is delivered from an interstate pipeline to a utility or large consumer. These prices are higher than wholesale prices because they reflect transportation costs in addition to commodity cost. Finally, the retail prices paid by residential and other small-end users are typically the highest gas prices because these customers must pay for not only the gas itself, but also the costs of transporting the gas to their city and the utility company's costs for providing full service delivery. Full service is more expensive because it requires a utility company to meet customers' full requirements, which can vary significantly depending on the weather. State regulatory agencies, such as public utility commissions, usually regulate the retail gas prices charged by generally larger, investor-owned gas utility companies, and local bodies, such as city councils, usually regulate the prices charged by generally smaller, municipally owned companies. Figure 3 shows the cost components for the residential price of natural gas.

[3]Spot market (sometimes referred to as the cash or physical market) prices are the current cash prices at which natural gas is sold at the various market locations.

Figure 3: Principal Components of Residential Natural Gas Price during Winter Heating Season



Source: GAO analysis of EIA's data, from 1999 through 2002.

Another development in the deregulated natural gas market is the use of natural gas derivatives—financial tools for managing risk that are based on natural gas prices. NYMEX introduced natural gas derivatives, in the form of futures and options contracts in 1990 and 1992, respectively. Using these derivatives, gas utilities, along with electric power generators, other large industries, and gas marketers, can hedge against price risk by locking in or setting an upper limit on the prices they will pay for future gas purchases. In the 1990s, the development of electronic trading systems and the Internet added another layer of complexity to the natural gas market. At that time, natural gas derivatives began to be bought and sold in the off-exchange OTC markets, such as the Intercontinental Exchange and the former EnronOnline. These OTC markets expanded both the terms (the size, maturity, and price) and types (OTC markets introduced swaps[4]) of hedging instruments available to natural gas marketplace participants.

Although the federal government has deregulated natural gas producer prices, three key agencies still maintain some role in ensuring that a competitive and informed natural gas market exists. FERC was established in 1977 as a successor to the Federal Power Commission and has responsibility for ensuring "just and reasonable rates" for the interstate transportation of natural gas, certain sales for resale of natural gas, and the wholesale price of electricity sold in interstate commerce. CFTC's mission is, in part, to oversee the nation's commodity futures and options markets, including natural gas markets, and to protect market users and the public from fraud, manipulation, and abusive practices. Finally, EIA is responsible for providing energy information (including natural gas) to meet the requirements of government, industry and the public that promotes sound policymaking, efficient markets, and public understanding. EIA was established by the Congress in 1977 and is charged with providing unbiased, professional analyses of energy issues and does not advocate policy. EIA's role is as a depository for energy information and it has no direct influence on natural gas prices or policy. However, the data that the EIA collects are used to address significant energy industry issues. EIA's natural gas data collection program is part of its National Energy Information System, a system created by the Federal Energy Administration Act of 1974, as amended, to help fulfill the agency's mandate to collect data that adequately describes the energy marketplace. According to EIA, adequate evaluation of the industry requires production, processing, transmission, distribution, storage, marketing, consumption, and price data.

The Securities and Exchange Commission (SEC), the Department of Justice (DOJ), and the Federal Trade Commission (FTC) also play roles in maintaining competitive energy markets through their regulation of firms participating in these markets. SEC administers and enforces federal securities laws to protect investors and to maintain fair, honest, and efficient markets. DOJ investigates and prosecutes illegal activities such as

[4]A commodity swap, including an energy swap, is typically between two parties who each promise to make a series of payments to the other, of which at least one series is based on a commodity price, such as the price of an energy product. For example, an airline might agree to make fixed cash payments on particular dates over a certain period and to receive from the counter party on those same dates payments that are based on an index of oil prices. This would enable the airline to hedge against volatility in its fuel costs.

price fixing, insider trading, and wire fraud. Both agencies have ongoing investigations into the financial activities of energy companies. DOJ also enforces the Sherman Antitrust Act, which prohibits all contracts, combinations and conspiracies that unreasonably restrain interstate and foreign trade. FTC shares authority with DOJ under section 7 of the Clayton Act to prohibit mergers or acquisitions that may substantially lessen competition or tend to create a monopoly. In addition, section 5 of the Federal Trade Commission Act prohibits "unfair methods of competition" and "unfair or deceptive acts or practices," thus giving FTC responsibilities in both the antitrust and consumer protection areas.

Market Forces Contributed to the Natural Gas Price Spike in 2000-2001, but Price Manipulation Has Not Been Ruled Out

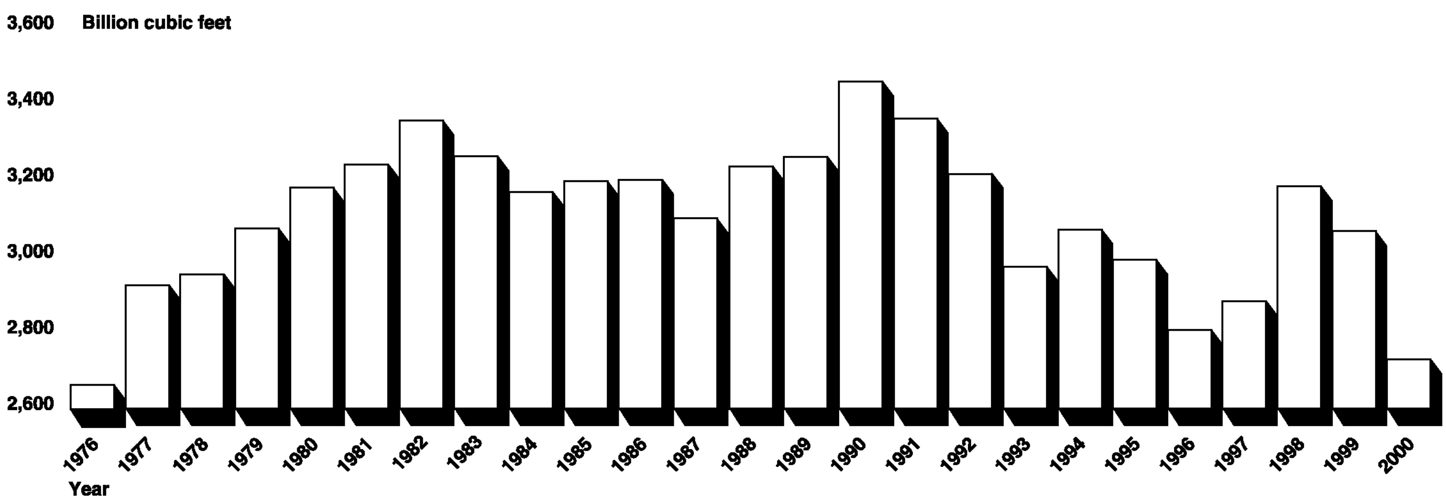
Available market evidence suggests that the inability of gas supplies to meet surging demands contributed to the natural gas price spike that occurred in 2000-2001. Specifically, natural gas supplies were constrained because of unusually low storage levels and the inability to quickly increase production levels. At the same time, demand during 2000-2001 was high because of extremely cold weather in the beginning of the winter and continuing strong economic growth. The price spike of 2000-2001 is consistent with the overall volatile nature of natural gas prices, which is driven by the short-term inelasticity of supply and demand that neither quickly nor easily adjusts to meet changes in the natural gas market. In addition, a lack of timely and accurate data about the overall natural gas market can create uncertainty about supply and demand conditions and further exacerbate price volatility. As a result, the combination of inelastic supply and demand means that shifts in natural gas supply or demand, real or perceived, can and are likely in the future to continue to cause volatility in the price of natural gas. While these market factors result in an inherent susceptibility to price volatility, there are indications that market manipulation may have occurred as well in the winter of 2000-2001. Several federal investigations looking into the possibility of such price manipulation in the natural gas market are currently ongoing. However, because these investigations are ongoing, a final determination of whether natural gas prices were manipulated, and if so, where and to what extent prices were further affected, has not yet been determined.

Natural Gas Supplies Were Constrained because of Low Storage Levels and Delays in Newly Produced Gas Reaching the Market

Based on our analysis of EIA data and interviews with EIA and other energy analysts, constrained natural gas supplies, caused by unusually low levels of gas in storage on the part of gas utilities and gas marketers, and the considerable time required for gas from new production to reach the marketplace, contributed to the increases in natural gas prices in 2000-2001.[5]

EIA data show that as of November 1, 2000, the volume of natural gas in storage was at the lowest level recorded for the beginning of a winter heating season since 1976[6]: only 2,732 billion cubic feet (bcf). In 4 of 5 months during the 2000-2001 winter heating season, the volumes of natural gas in storage were at record low levels. And at the end of March 2001, the volume of gas in storage dropped to 742 bcf, the lowest level ever recorded by EIA, or 36 percent below the level in March 2000.

Figure 4: Available Gas in Storage at the Beginning of the Winter Heating Season, November 1976-November 2000



Source: GAO analysis of EIA's data.

[5]In general, gas supplies were not significantly hindered by transmission or pipeline capacity constraints. However, EIA reported that although the use of natural gas pipeline capacity rose to high levels (90 to 100 percent in many locations), the movement of gas from production areas to end-use markets encountered few problems, except in some fast-growing market areas, such as California, Florida, and New York. In California, for example, according to the California Energy Commission, insufficient capacity within the state and on the interstate El Paso pipeline system both contributed to the high price of natural gas in the fall and winter of 2000.

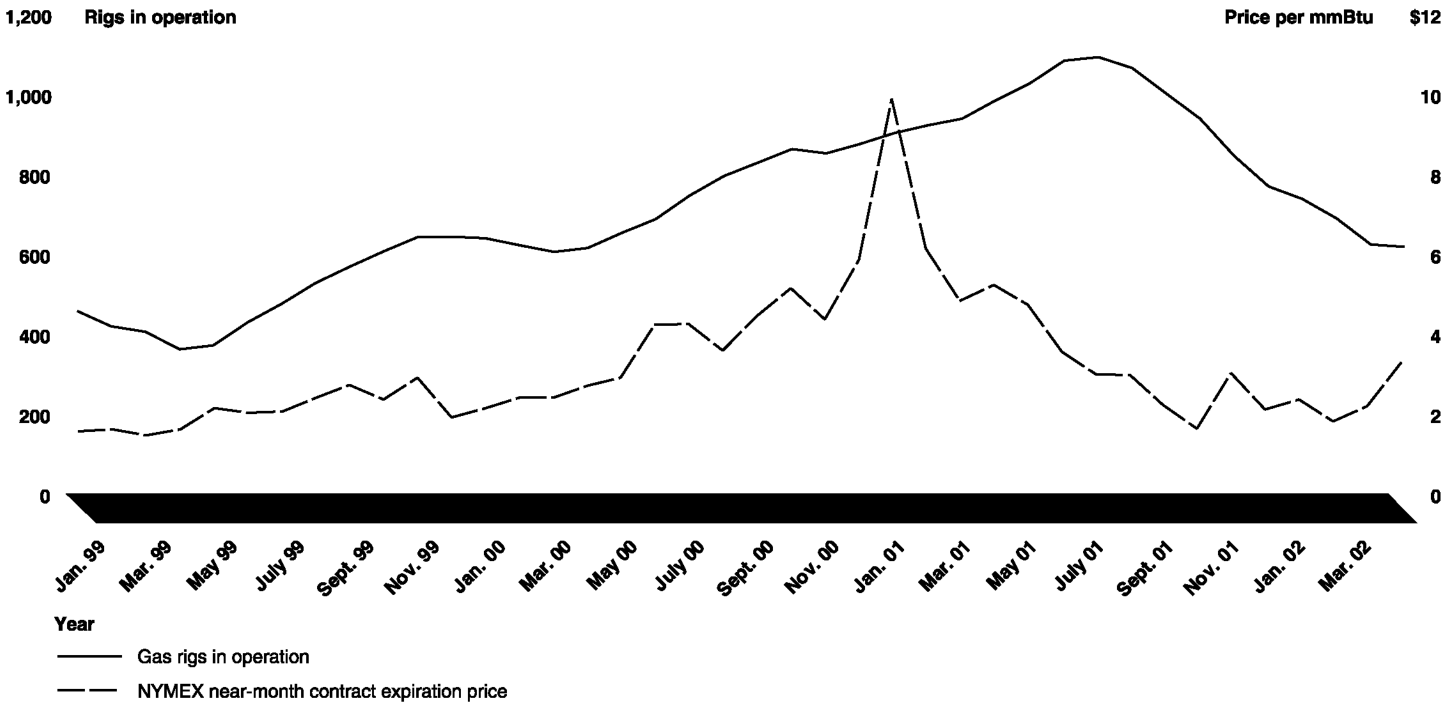
[6]The winter heating season is typically defined as November 1 through March 31.

These low storage levels resulted primarily because wholesale gas prices from April through September 2000 were higher than normal, climbing from around $3 to over $5 per mmBtu. According to EIA, these prices caused some storage users to postpone buying gas to inject into storage in the hope that prices would eventually decrease before the winter. However, instead of decreasing, gas prices generally stayed high and the volume of gas placed into storage for the winter heating season did not reach normal levels. According to industry experts, natural gas prices were high in the summer of 2000 because of the increased use of natural gas for electric generation. The increased demand for electric generation was compounded by the warmer-than-normal weather in the South and West, which increased the demand for gas-fired electricity to run air conditioning units. In addition, some companies and marketers that had put gas into storage earlier in the year reportedly sold it for profit when gas prices increased later that year, further depleting the already low storage reserves. In late September and October 2000, the industry did put more gas into storage at rates higher than the previous 5-year average for this period to prepare for the coming heating season; however, this late surge of injections of gas into storage did not bring storage volumes up to their usual levels.

Adding to the supply constraints caused by low storage levels was the fact that producers could not quickly increase their production levels to meet the increasing demand for natural gas. During the winter of 2000-2001, almost all of the gas that could be produced from existing natural gas wells was being produced and sent into the marketplace. According to EIA analysts, when over 90 percent of the maximum possible gas productive capacity from wells is being utilized, the natural gas market is at greater risk for price spikes. Data supplied by EIA show that this was true during the winter of 2000-2001, when the nation’s natural gas utilization rate was above 90 percent and reached levels close to 100 percent in certain areas of the country. Therefore, new gas production was needed to respond to increased demand, but this new production could not be developed fast enough to keep prices from rising.

Prior to 2000, drilling activity was lower as supply was sufficient and prices were lower. However, in response to the higher prices in 2000, natural gas producers took action to increase their production by increasing the number of new gas wells they drilled. As shown in figure 5, the number of drilling rigs began increasing in the April to May 2000 time frame, when gas prices first rose above $3 per mmBtu and continued to increase for more than a year. However, the number of drilling rigs in operation stopped increasing around July 2001, when gas prices again fell below $3 and producers no longer had the economic incentive to increase production.

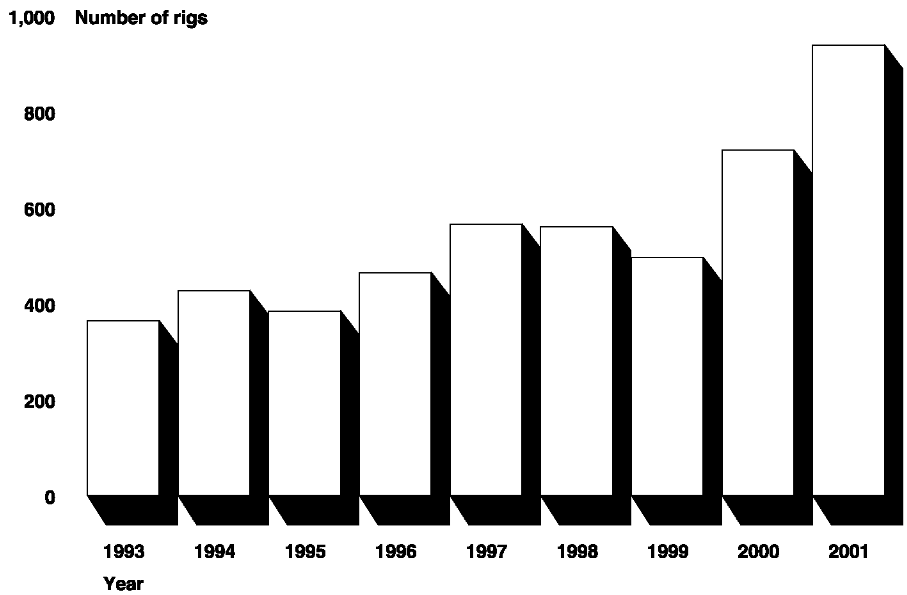
Figure 5: Number of Gas Rigs in Operation and Gas Prices



Source: GAO analysis of DRI and industry data.

Although the number of new natural gas wells being drilled in 2001 decreased when gas prices decreased, the monthly average number of rigs in use that year was the highest recorded since natural gas prices were deregulated in 1993. Figure 6 compares the number of natural gas rigs in operation for the years 1993 through 2001.

Figure 6: Monthly Average Number of Natural Gas Rigs in Use, 1993–2001



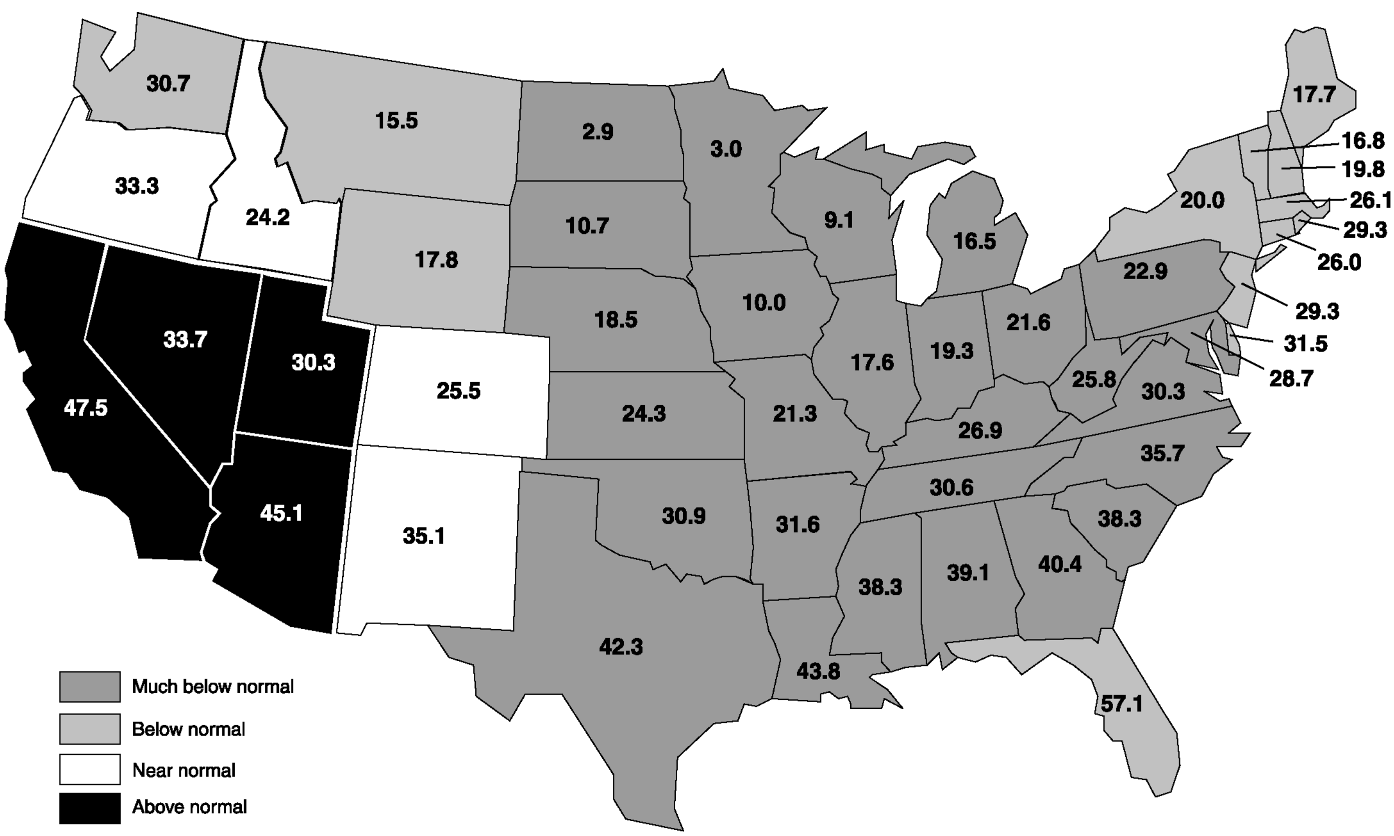
Source: GAO analysis of industry data.

The effect of this increased drilling activity was not immediately felt in the supply of natural gas available in the marketplace because there is a lag time of 6 to 18 months before gas produced from new wells reaches the market. Furthermore, according to EIA, there is an inherent delay between gas price changes and changes in drilling activity. Gas prices began to increase around May 2000 and peaked around January 2001, but rig counts did not peak until July 2001 (see fig. 5). Therefore, the increased drilling in 2000 and 2001 did not result in an immediate increase in the production of natural gas, and the new production that did occur did not reach the marketplace in time to respond to the growing demand and slow the rising prices. Moreover, industry officials told us that the typical delay associated with getting newly produced gas to the marketplace was exacerbated by the low number of gas drilling rigs that were in operation before the price increase in 2000. According to these officials, low natural gas prices beginning in late 1998 and continuing through 1999 had caused producers to greatly reduce the number of drilling rigs in operation. In fact, as figure 6 shows, the number of natural gas drilling rigs operating in 1999 averaged only 496 per month and hit an almost 4-year low in April when the average number of operating rigs dropped to 371. Therefore, natural gas producers faced more than a normal delay in increasing their natural gas drilling activity because of limited equipment availability.

Natural Gas Demand Increased because of Cold Weather and the Strong Economy

At the same time the country was facing constrained gas supplies, a surging increase in demand, caused chiefly by cold weather and a strong economy, also contributed to the increases in natural gas prices in the winter of 2000-2001. Nationwide, extremely cold weather early in the winter heating season was a key reason for the peak in natural gas demand. This increased demand came primarily from the residential and commercial customers who use natural gas for heating. According to data from the National Climatic Data Center, November 2000 was the coldest November recorded for almost 90 years, with temperatures below normal or much below normal across most of the country. In December 2000, temperatures continued to remain cold, with 40 of the 48 contiguous states showing temperatures below or much below normal (see fig. 7).

Figure 7: Mean Temperatures in the Continental United States for December 2000, in Degrees Fahrenheit



Source: National Climatic Data Center.

According to EIA data, these frigid temperatures caused record natural gas withdrawals from storage in November 2000, followed by the highest level of withdrawals in 11 years for the month of December. These relatively large withdrawals, coupled with the low storage levels at the beginning of the winter heating season, caused some people in the natural gas industry to believe that storage levels in some areas would not be sufficient to last through the winter if the cold weather continued. In fact, gas supplies did not run out because the high gas prices motivated some consumers to reduce consumption or use substitute fuels when possible, especially in the industrial and electric generation sectors. In addition, gas supplies did not run out because the weather was milder during the rest of the winter. However, even with this eventual decrease in demand, by the end of the winter heating season on March 31, 2001, the volume of natural gas in storage was at its lowest level since EIA began its complete monthly data series beginning in September 1975.

In addition, continuing economic growth throughout the 1990s and into 2000 expanded the potential demand for natural gas and contributed to the price spike that occurred in 2000-2001. This growth occurred in major sectors of natural gas consumption: residential, commercial, industrial, and electric generation. The strong economy during the 1990s had boosted new home construction, and most of these homes were heated with natural gas. Housing data that we reviewed show that from 1991 to 1999, two-thirds of the new homes and more than one-half of the new multifamily buildings constructed were heated with natural gas. Further, many of these new houses tended to be larger, thus increasing the potential for high natural gas consumption during colder weather. The number of commercial gas customers also increased from 4.6 million in 1995 to 5.1 million in 2000, while natural gas consumption in this sector rose by 6 percent. Gas consumption in the industrial sector remained high, although it has decreased slightly since 1997 in part because of more efficient equipment. Because of its clean burning properties, natural gas is now the preferred source of energy for most new electric generation capacity. Gas-fired electric generation facilities accounted for only about 23 percent of natural gas consumption in the United States in 2001, but account for a greater percentage during the summer, when electricity demand goes up because of the use of air conditioning.

Natural Gas Market Supply and Demand Characteristics Cause Price Spikes

Natural gas price volatility, as occurred during the winter of 2000-2001, is driven by inelastic supply and demand, which means neither can quickly nor easily adjust to meet changes in the natural gas market. The supply of gas from new production wells cannot quickly increase to meet higher demand because of the lag time required to get the newly produced gas into the marketplace. Similarly, the demand for natural gas does not quickly drop in response to higher prices: some consumers do not have easy access to alternative fuels, so their demand does not decrease significantly even when natural gas prices increase. In addition, a lack of timely and accurate data about the overall natural gas market can create uncertainty about supply and demand conditions and further exacerbate price volatility. As a result, the combination of inelastic supply and demand means that small shifts in natural gas supply or demand, real or perceived, can and are likely to continue to cause relatively large fluctuations in the price of natural gas.

Natural Gas Supply Is Inelastic, and Information Is Limited

The inelastic nature of natural gas means that supply is slow to respond to price changes in the marketplace. The immediate supply of natural gas primarily comprises gas coming from production that goes straight into the market and gas placed into storage during the warmer summer season for use during the winter heating season. On the production side, there is a significant delay from the time drilling begins to the time when newly produced gas enters the marketplace. Developing additional supplies from new wells and building the new infrastructure required to deliver the newly produced gas to market—such as gas processing plants and pipelines—can take considerable time. The amount of time required to get new gas to the market depends on several factors, including the location of the natural gas well. For example, natural gas industry sources told us that gas coming from new wells drilled in areas with established reserves that are not deep in the ground takes about 6 months to reach the market. However, it takes much longer for gas being extracted from very deep wells, from new fields, or from offshore wells to reach the marketplace. In addition, gas extracted from a new field often cannot reach the marketplace until a pipeline segment and/or gathering line is constructed, and this requires even more time. Thus, new gas production often cannot be brought into the marketplace quickly enough to meet increases in demand. In addition, the amount of natural gas available from storage to meet increasing demands is limited. According to industry officials, natural gas is generally purchased and injected into storage during the 7-month period from April through October. This gas is then withdrawn from storage for heating and other use during the winter heating season running from November through March. Once the injection season is over, the amount of gas in storage is typically set. Thus, when people in the gas industry become concerned that the available supply of gas will not be sufficient to last through the winter heating season, a significant price spike can occur, as it did in 1996 and again in 2000-2001, when the amounts of gas in storage were at low levels.

Compounding the limited ability of production to respond quickly and the limited gas in storage is the lack of comprehensive and timely information on these market characteristics. This uncertainty can make it difficult for market participants to determine when shifts in supply are occurring, leading to increased and frequent speculation that may ultimately increase price volatility because of perceived shifts in supply. According to EIA, the agency's monthly production data are subject to problems of accuracy and timeliness. First, the forms used to report production data vary from state to state and often do not include all information requested by EIA. Therefore, EIA must estimate marketed production from whatever data elements are submitted, information in state publications and web sites, the trade press, or prior year data. Also, EIA data is collected through an optional survey. If a state does not comply with information requests, the federal government has no authority to require it to provide information. In addition, monthly production data for a certain year are, for some states, available to EIA only in the late summer of the following year, leading to inherent delays in reporting. Late or incomplete reports from the states to EIA are common.

Incorrect information concerning storage can also greatly affect the market. As discussed above, because timely production information is not available, storage data have become a widely used indicator to estimate the supply of natural gas. When this information is incorrect, it can increase volatility in the natural gas market. For example, when AGA reported on August 15, 2001, that injections for the week ended Friday, August 10 totaled a record low of 3 bcf, the September futures contract daily settlement price jumped by 12 percent from the previous day. Analysts had predicted that injections for that week would range from 45 to 70 bcf. Later, AGA discovered that it had received erroneous data from an entity included in its survey and issued a corrected gas storage report on August 22 showing that gas injection during the week ending August 10, 2001, was 50 bcf. As a result, the September futures contract price on August 22 decreased by more than 10 percent from the day before. On October 12, 2001, AGA announced that in 2002 it would stop providing weekly reports on the volume of natural gas in underground storage. AGA said that it was discontinuing its reporting of storage data primarily because the staff time required to conduct the gas storage survey drained staff resources that could be redirected to programs more beneficial to its members. Shortly after the AGA announcement, the Secretary of the Department of Energy announced that because of the importance of natural gas storage data in forecasting winter gas prices and demand, EIA would begin providing this data in a weekly report.

Natural Gas Demand Is Inelastic, and Information Is Limited

The demand for natural gas is inelastic to varying degrees among major gas consuming sectors: residential, commercial, industrial, and electric generation. Demand from residential and commercial customers is perhaps the most inelastic because heat is generally a necessity, not a luxury. Those consumers that heat their homes and businesses with natural gas will require a certain level of heat even if gas prices are quite high. Furthermore, they cannot easily respond to high natural gas prices in the short run by switching to a more economic fuel source for heat. In addition, many of these customers do not know beforehand that they are paying higher gas prices because they are customarily billed later for gas they are currently using.

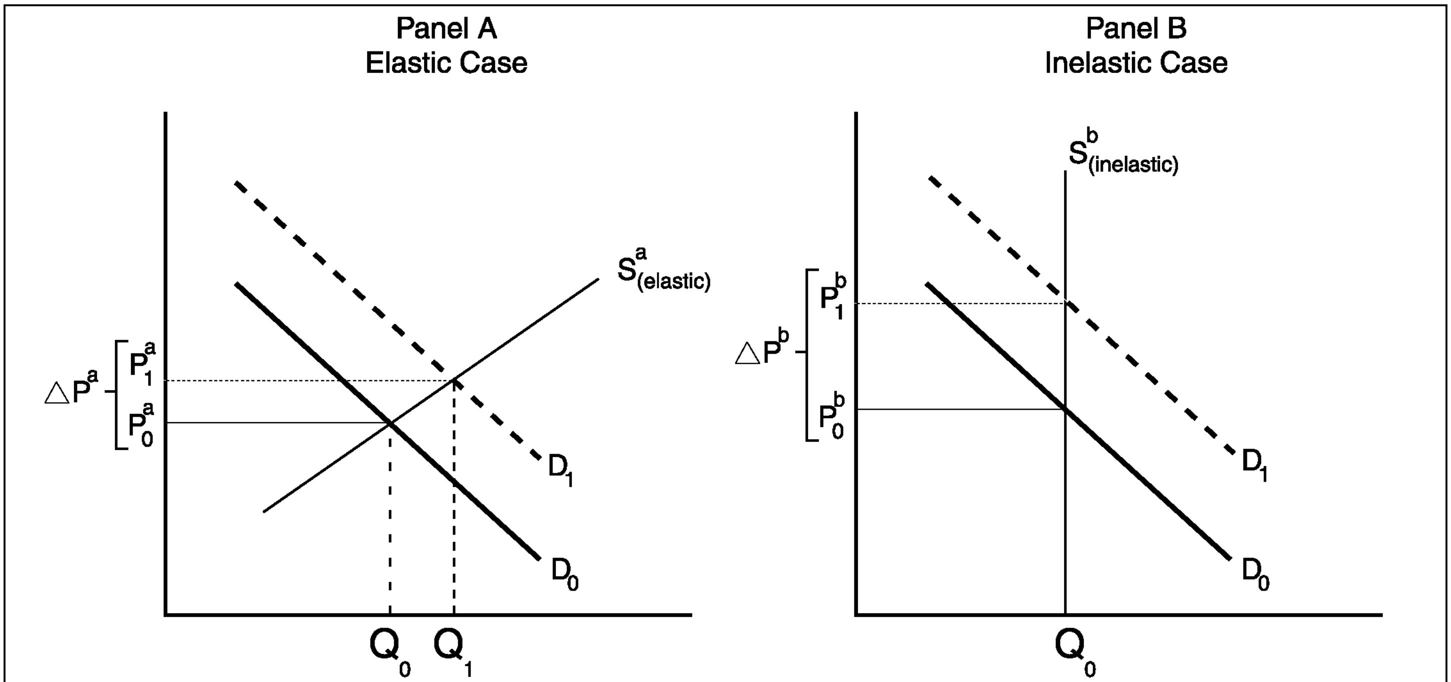
Industrial natural gas demand is more elastic than demand from residential and commercial customers. For example, some industrial customers have the ability to switch from natural gas to other fuels when natural gas prices rise. However, many do not have this capability and others have limited fuel switching capability. As natural gas prices rise, some industrial customers may choose to reduce their operations and sell the gas they had under contract to the highest bidder. When natural gas prices rose significantly in 2000-2001, this option was more profitable for certain industrial users than if they had continued their operations using natural gas at higher-than-normal prices. Natural gas demand for electric generation may now be more elastic, but according to industry experts it is becoming more inelastic. Previously, many of these users had facilities that could use either natural gas or an alternate fuel, such as oil, depending on which energy source was less expensive. However, natural gas prices were low throughout the 1990s, so many electric generation facilities decided to use natural gas as their only source of energy, thus increasing their dependency on natural gas. The demand for natural gas in the electric generation sector is growing faster than in any other sector and if EIA's projections for gas-fired electricity are realized, this sector will likely have a significant effect on future natural gas prices. EIA projects that the demand for natural gas in the electric generation sector will grow at an annual rate of 4.5 percent, and by 2020 the demand will have risen to 10.3 tcf of gas, accounting for 30 percent of the natural gas used annually in this country. In addition, industry analysts told us that because of the high demand for gas-fired electricity in some markets, some electric generating facilities are willing to pay premium prices for the natural gas needed to produce this electricity.

As with gas supply data, some aspects of natural gas demand information are also limited, making it difficult for the market to see real changes in demand. The resulting increased speculation about perceived shifts in demand can also exacerbate price volatility. According to EIA, the growth and restructuring of the natural gas industry have made it more difficult to collect data concerning natural gas demand. For example, changes in certain regulatory requirements have led to the elimination of information that EIA needs to ensure the quality and completeness of its data. In addition, firms providing natural gas delivery do not always know the intended use for the gas they are delivering. For example, a gas supplier could deliver gas to a city building that contains both residential apartments and retail space. The supplier has no way to know what percentage of the gas delivered is used for what purpose and therefore cannot determine in what usage sector the gas should be reported. In the electric generation sector, the importance of nonutility generators, including independent power producers and cogenerators, is growing. In the past, EIA has included these entities in the statistics it develops for industrial or commercial users of natural gas sectors, thereby underreporting the amount of gas used to generate electricity. However, EIA is implementing a better approach to measure and report the amount of natural gas used for electric generation by nonutility generators. Also, EIA recently changed how it estimates and presents data on the fuels used to produce electricity. The purpose of this change is to improve data quality, ensure that data are reported consistently throughout EIA publications, and provide users with a better understanding of how fuels are consumed.

Short-term Inelasticity Means Small Shifts in Supply or Demand Can Lead to Significant Price Fluctuations

Any market with inelastic supply and demand characteristics—as is the case in the natural gas market—is more susceptible to significant price fluctuations than a more elastic market: in an inelastic market, relatively small shifts in supply or demand can result in significant price changes. Natural gas supply is relatively fixed in the short term; it is limited to available storage and current production and cannot be quickly increased to meet increased demand. Thus, an increase in demand will result in a greater increase in price than if the supply were more elastic. Basically, in the perfectly inelastic supply market, more demand competes for the same level of supply, driving prices higher than they would go if supply were more readily available—more elastic. Figure 8 illustrates this example by comparing the smaller price increase in a market with elastic supply (panel A) with the larger price increase in a market with perfectly inelastic supply (panel B) when faced with the same increased level of demand. Figure 9 goes farther, illustrating this difference for a market with both inelastic supply and demand—as is the case with the natural gas market. Figure 9 compares the smaller price increase in a market with both elastic supply and demand (panel A) with the larger price increase in a market with inelastic supply and demand (panel B) when demand increases and supply decreases.

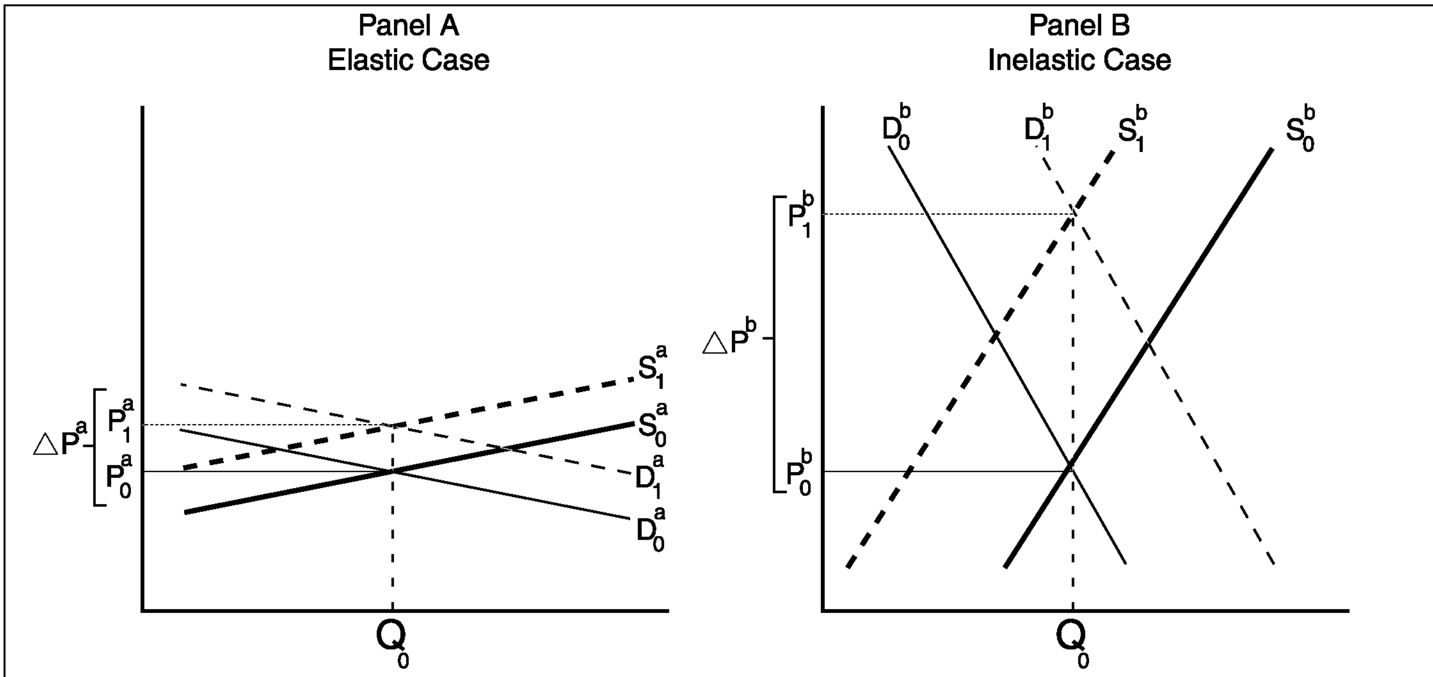
Figure 8: Comparison of Price Impacts of Elastic Supply and Inelastic Supply



Source: GAO analysis.

Note: In panel A, assume we have a good with elastic supply; elastic supply is represented by a supply line whose upward slope is relatively not very steep. Initially, the price and quantity settle at P^a_0 and quantity Q_0 as determined by the intersection of supply S^a and demand D_0. Next, assume that demand increases, as depicted by an outward shift in the demand line to D_1. Because supply is somewhat elastic, additional supply is made available to meet the increased demand, albeit at a higher price P^a_1. The increase in price is represented by ΔP^a—the difference between P^a_1 and P^a_0. However, in an inelastic supply situation, the supply response is weaker. A more limited quantity is supplied to the market to meet the increased demand, resulting in a steeper rise in price than in the more elastic case. Graphically, this inelasticity is represented by a supply line that is much steeper than the elastic supply line. Taking an extreme example, assume that supply is totally inelastic—that is, supply is fixed no matter what the demand—as depicted in panel B with a vertical supply line, S^b. The initial price and quantity are the same as in panel A. Given the fixed supply, in order to meet the same increase in demand to D_1, the price would have to increase to P^b_1 to “choke off” the excess demand. The increase in price from P^b_0 to P^b_1 for the inelastic supply case, as represented by ΔP^b, is significantly higher than the increase in price in the elastic supply case, ΔP^a.

Figure 9: Comparison of Price Impacts of Elastic and Inelastic Supply and Demand



Source: GAO analysis.

Note: To provide a more complete picture, figure 9 compares a market with elastic supply and demand with a market with inelastic supply and demand—like the natural gas market—to further illustrate the greater price response to shifts in inelastic supply and demand. The elastic supply and demand market (panel A) has a relatively less steep supply and demand lines, while the inelastic supply and demand market (panel B) is characterized by much steeper supply and demand lines. The primary observation is the difference in the price response to changes in supply and demand in the elastic market in panel A (P^a_0 vs P^a_1) compared with the price response in the inelastic market in panel B (P^b_0 vs P^b_1). In both examples, supply drops as depicted by an inward shift from S_0 to S_1. In the gas market, this drop could be due, for example, to an accident that disrupts a major pipeline. Also, in both examples, demand rises, as depicted by an outward shift from D_0 to D_1. In the gas market, this could be the result of an unusually cold winter snap. We have constructed both examples in such a way as to leave the quantity of the commodity unchanged at Q_0. As can be seen, in the market with elastic supply and demand, the decline in supply and the rise in demand result in a relatively small price increase (ΔP^a). However, in the market with inelastic supply and demand, the increase in price due to the supply and demand shifts is considerably larger (ΔP^b).

Evidence of Natural Gas Market Manipulation Found, but Federal Investigations Still Ongoing

On February 13, 2002, FERC commissioners directed staff to undertake a fact-finding investigation into whether any entity, including Enron Corporation, manipulated short-term prices in electric energy or natural gas markets in the West or otherwise exercised undue influence over wholesale electric prices in the West, for the period January 1, 2000, forward. On March 5, 2002, FERC staff issued an information request to companies that sold energy in the West during this period to report on their capacity and energy sales transactions. On May 6, 2002, counsel for Enron released several memos to FERC staff that indicated the company had actively worked at manipulating California's wholesale electric power markets. On May 8, 2002, FERC issued an "Admit or Deny" order requiring other companies to either admit or deny they engaged in strategies that might have inflated market prices during California's energy crisis of 2000-2001. A May 22, 2002, FERC order further expanded the investigation by requesting that natural gas sellers in both the West and Texas provide information on "wash trading."[7] In an initial staff report issued August 13, 2002, FERC found indications that several companies, including Enron, may have manipulated spot prices upward for natural gas delivered to California during 2000-2001.[8] FERC staff reported that during the months October 2000 to July 2001, the correlation of spot prices for natural gas at the California delivery points with prices at producing basins in the Southwest and the Rockies and Henry Hub was abnormally low. FERC staff found that published natural gas price data are susceptible to manipulation and cannot be independently validated. The staff report noted that the lack of formal verification opens the door for entities to deliberately misreport information in order to manipulate prices and/or volumes for both electricity and natural gas. The staff report concluded that in the absence of some form of double-checking, such misreporting is likely to be undetected in the reporting process and uncorrected when prices are published. FERC staff also found that Enron's trading strategies, described in internal Enron memos, used false information in an attempt to manipulate prices. The FERC staff report stated that while the exact economic impact of Enron's trading strategies remains difficult to determine, the Enron trading strategies have adversely affected the confidence of the markets (electric and natural gas) far beyond their dollar impact on spot prices. Based on the staff report, FERC ordered formal investigations into instances of possible misconduct by Avista Corporation and Avista Energy, Inc., El Paso Electric Company, and three Enron

[7]Wash trading, also know as "round-trip trading," is defined in the natural gas market as "the sale of natural gas together with a simultaneous or pre-arranged purchase of the same product at or near the same price." It gives the appearance of trading when no bona fide, competitive trade has occurred. The practice creates the false impression that an energy firm sold more power or natural gas than it actually controlled and may inflate the price of the commodity to the extent that the artificial and higher price created by the wash trade is used as a basis for pricing.

[8]*Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations: Published Natural Gas Price Data; and Enron Trading Strategies* (FERC, Aug. 13, 2002).

corporate affiliates—Enron Power Marketing, Inc., Enron Capital and Trade Resources Corporation, and Portland General Electric Corporation.

In addition to the FERC investigation, on September 23, 2002, a FERC administrative law judge found that El Paso Natural Gas Company exercised market power during the 2000-2001 winter heating season by withholding substantial volumes of pipeline capacity to its California delivery points, thereby tightening natural gas supply to the state and increasing its price. The California Public Utilities Commission originally brought the case, filing a complaint with FERC in 2000. The judge recommended that FERC commissioners institute penalty procedures. The Commission will review the judge's recommended decision. In addition to the FERC investigations, CFTC Chairman James E. Newsome confirmed during congressional testimony in March 2002 and again at a press conference in May 2002 that CFTC had began an investigation into various energy trading schemes, including possible wash trading, in gas and power futures markets. However, consistent with CFTC policy on ongoing investigations, CFTC could not tell us about the scope or reporting deadlines of its investigation.

Federal Government Faces Challenges in Ensuring a Competitive and Informed Natural Gas Marketplace

FERC, CFTC, and EIA play front-line roles in promoting a competitive natural gas marketplace by monitoring business activities and deterring anticompetitive actions that could undermine these markets, and obtaining information and analyzing trends in the industry that are used by decisionmakers in both industry and government. However, regulatory gaps and outdated data collection efforts have impeded effective federal oversight of the natural gas marketplace to ensure competition and limited its ability to provide market information. As we have recently reported, FERC has not adequately revised its regulatory and oversight approach to respond to the transition to competitive energy markets. As a result, it has been slow to react to charges of possible market manipulation and lacks assurances that wholesale natural gas and electricity prices are just and reasonable. We note, however, that FERC has recently take actions to correct this with the formation of the Office of Market Oversight and Investigation (OMOI). In addition, CTFC—the federal agency responsible for fostering competitive commodity futures markets—generally does not have regulatory authority over trading in the OTC derivatives markets. Finally, EIA recognizes that most elements of its natural gas data collection program were set in place more than 20 years ago, well before deregulation spawned a host of new entities and markets that influence natural gas prices. EIA recognizes that its ability to provide information that promotes understanding of the market price of natural gas has declined significantly and is currently reevaluating its data collection needs.

FERC Faces Challenges That Impede Effective Oversight

Under federal law, FERC is responsible for regulating the terms, conditions, and rates for interstate transportation by natural gas pipelines and public utilities to ensure that wholesale prices for natural gas and electricity, sold and transported in interstate commerce, are "just and reasonable." However, FERC jurisdiction over sales for resale is limited to domestic gas sold by pipelines, local distribution companies, and their affiliates. The Commission does not prescribe prices for these commodity sales. As energy markets deregulate, FERC has concluded that its approach to ensuring just and reasonable prices needs to change: from one of reviewing individual companies' rate requests and supporting cost data to one of proactively monitoring energy markets to ensure that they are working well to produce competitive prices. However, we reported in June 2002[9] that FERC has not yet adequately revised its approach to regulating and overseeing the nation's natural gas and electric power industries. The problems we identified include the following:

- FERC is using legal authorities to regulate competitive markets that were enacted when the energy industries were regulated monopolies. For instance, FERC generally does not have the authority to levy meaningful civil penalties. While this authority may not have been necessary when energy industries were regulated monopolies, it is important, in today's market, if FERC is to deter anticompetitive behavior or violations of market rules by market participants.
- FERC's oversight initiatives have been incomplete or ineffective. FERC initiatives to monitor competitive markets have served more to help educate FERC's staff about the new markets than produce effective oversight. Additional market data available to staff have not been used to initiate an enforcement action or to confirm or refute a problem identified elsewhere in the agency.
- FERC's organizational structure limits its ability to monitor competitive markets because it diffuses its market oversight function, making it more difficult to provide the communication, focus, and management attention needed to successfully implement a new regulatory and oversight approach.

[9]*Energy Markets: Concerted Actions Needed by FERC to Confront Challenges That Impede Effective Oversight* (GAO-02-656, June 14, 2002).

- FERC must overcome significant human capital challenges, such as recruitment and retention of qualified staff.

We concluded that absent an effective regulatory and oversight approach, FERC lacks assurance that today's energy markets are producing interstate wholesale natural gas and electricity prices that are just and reasonable. FERC's response to the natural gas price spikes during the winter of 2000-2001 highlighted the challenges it faces in providing market oversight. Because FERC did not have a system in place to monitor natural gas spot markets, it was slow in responding to charges of possible market manipulation. For example, the investigation into whether Enron Corporation or others manipulated short-term prices in electric energy or natural gas markets in the West for the period January 1, 2000, forward did not begin until February 2002, and remains incomplete almost 2 years after natural gas prices first spiked. According to FERC, this investigation should be completed by the first quarter of 2003. Further, this investigation was largely reactive to complaints and accusations of improper behavior by energy companies such as Enron, and relies heavily on requests for information from various energy companies. For example, the investigation had to rely on energy companies to report back to FERC, through information requests or "Admit or Deny" orders on whether they had engaged in any behavior that might have inflated market prices.

Our previous report recommended that FERC take actions to ensure that it can effectively carry out its responsibilities for overseeing interstate wholesale natural gas and electricity markets, such as updating its strategic plan for overseeing energy markets and developing a training action plan for staff involved or potentially involved in carrying out FERC's market oversight functions. We also suggested that the Congress might wish to convene public hearings to review FERC's authorization legislation and determine, in consultation with FERC Commissioners, whether FERC's authorities needed to be revised in the light of the changing energy markets. We also suggested that the Congress might want to consider providing FERC with the appropriate range of authorities to levy civil penalties against market participants that engage in anticompetitive behavior and violate market rules. FERC agreed with the conclusions of our report and noted that its internal restructuring to support its new market oversight role has not kept pace with the speed of energy industry restructuring. Specifically, FERC stated that it needs additional statutory authority—in particular, the ability to assess a meaningful range of penalties for violations of the law or FERC rules. To address organizational problems, FERC created a new Office of Market Oversight and Investigation whose purpose is to oversee and assess the fair and efficient operations of energy markets. OMOI reports directly to FERC's Chairman and its responsibilities include understanding energy markets and risk management, measuring market performance, investigating compliance violations, and analyzing market data. According to FERC, a multidisciplinary team of 120 people will staff OMOI and 89 of them have been hired.

In addition to the statutory and organizational problems that limit its oversight of energy markets, FERC is in the early stages of assessing what information it needs to have in order to monitor and regulate competitive markets for wholesale electricity, and to ensure that open access natural gas transportation and electric transmission services are provided fairly and efficiently, without the exploitation of market power. In September 2001, FERC formed a Comprehensive Information Assessment Team to survey its current data collections to ensure they meet FERC's traditional and future information needs. The team's goal is to assess and propose changes to FERC's reporting requirements in order to improve FERC's monitoring of competitive markets and performance of traditional regulatory duties.

In addition to these problems, current FERC regulations governing the conduct of natural gas pipeline companies with affiliates are outdated. Because these regulations were set in place in 1988, significant changes have occurred in the natural gas marketplace, such as unbundling, capacity release, growth of e-commerce, and market growth and consolidation, that have expanded the number and types of pipeline affiliates. FERC's current affiliate regulations do not address the potential exercise of market power through sharing information among pipeline companies and their affiliates because the regulations exclude nonmarketing affiliates, local distribution companies, and affiliated producers and gatherers. FERC issued a Notice of Proposed Rulemaking in September 2001, which puts forth new affiliate standards that would apply uniformly to natural gas pipeline companies by extending standards of conduct to relationships between the transmission providers, and all affiliates.

CFTC Regulatory Oversight Varies Among Markets

CFTC's regulatory oversight of natural gas derivatives varies among natural gas derivatives markets. CFTC was created in 1974 to oversee the nation's commodity futures and options markets and has a twofold mission: to foster transparent, competitive, and financially sound markets, and to protect market users and the public from fraud, manipulation, and abusive practices in those markets. NYMEX—the largest exchange that trades natural gas derivatives—is a federally designated contract market that is fully regulated by CFTC. CFTC staff routinely monitored trading and price relationships in the NYMEX natural gas contracts and found no reason to take enforcement action during the 2000-2001 natural gas price spike. There are numerous off-exchange, or OTC, derivatives markets that trade substantial volumes of natural gas derivatives and that are generally not subject to CFTC regulations.[10] CFTC is currently conducting an investigation into whether wash trading or other price-manipulative misconduct occurred in the OTC or spot markets during the price spike period. However, until CFTC's investigation is complete, it is unknown, what role, if any, these markets may have played in the 2000-2001 natural gas price spike, or what, if any, enforcement or other actions may result.

NYMEX reported that the average daily contract amount[11] of its derivatives trades for all of 2001 was $13 billion. As a federally designated contract market, NYMEX must file all terms and conditions of traded contracts and contract changes with CFTC. CFTC reviews exchange rules to ensure that listed contracts are not readily susceptible to manipulation; oversees the registration of participants on the exchange; and requires daily reporting of key market and trader position information such as position size, trading volume, open interest,[12] and prices. NYMEX participants are subject to CFTC's antifraud and antimanipulation provisions, including prohibitions on wash trading. In addition, NYMEX is required to conduct market surveillance and enforce minimum financial requirements for its members. Also, because NYMEX acts as a clearinghouse,[13] it protects all participants against counterparty credit risk, which is the risk of failure by

[10]The Commodity Exchange Act (CEA) excludes certain types of derivatives entirely from the CFTC's jurisdiction, such as off-exchange swaps between certain qualifying parties (called "eligible contract participants") that are based on broad economic measures like interest rates or stock indices beyond the control of the parties. The act exempts certain other types of derivatives from much, but not all, of the CFTC's jurisdiction, such as electronically-executed multilateral transactions in energy or metals commodities among certain qualifying commercial enterprises (called "eligible commercial entities"), over which the CFTC retains antifraud and antimanipulation authority.

[11]Contract amount is a measure of the volume of certain derivatives (such as futures and options) that is based on the value of the underlying contract.

[12]Open interest is the total number of futures contracts long or short in a delivery month or market that have been entered into and not yet liquidated by an offsetting transaction or fulfilled by delivery.

[13]A clearinghouse is an institution that acts as the buyer to every seller and the seller to every buyer, thereby guaranteeing performance on a contract.

a contract counterparty to settle the contract by paying funds as they become due as a result of the trade.

For NYMEX natural gas contracts, CFTC market surveillance staff told us they found no market problems that required CFTC intervention during the winter of 2000-2001. Surveillance staff told us that because no unusual problems or excessive speculative positions were identified during this period using the customary daily surveillance tools and procedures, no special reports were prepared by CFTC pertaining to the price spike. Based on its monitoring, CFTC concluded that NYMEX natural gas contracts behaved normally during this period and that natural gas futures prices, though high, were driven by supply and demand. Because of the high prices and price volatility during this period, the natural gas futures market was discussed at 18 of the Commission's weekly surveillance briefings in September 2000 through March 2001, which represented a high frequency for the commodity.

Natural gas OTC markets are structured differently than NYMEX and generally are not subject to CFTC regulation. Natural gas OTC derivatives can be traded on multilateral basis (typically on an electronic trading facility in which multiple buyers and sellers participate) or on a bilateral, or principal-to-principal basis, which may also be through an electronic trading facility. Unlike exchange-traded derivatives, the maturity dates, quantities, and delivery points for the commodities underlying the derivatives offered in the OTC markets are negotiable among participants and are not subject to CFTC review and approval. The Commodity Futures Modernization Act (CFMA) of 2000 provided a series of exclusions and exemptions that removed these markets from most of CFTC's regulatory authority. Therefore, these markets typically are not subject to daily monitoring by CFTC. However, CFTC can take action to address the use of OTC transactions in natural gas derivatives, other than swaps, to manipulate the underlying commodity and, depending on the parties to the transactions, the Commission can take action to prevent or address fraud.[14] Also, CFTC has authority to investigate manipulation of commodity prices. Finally, participants in the OTC derivatives markets generally bear counterparty credit risk, but a clearinghouse function is

[14]Nonswap bi-lateral natural gas OTC transactions between eligible commercial entities are subject to provisions in the CEA prohibiting manipulation. Such transactions involving participants that do not qualify as eligible commercial entities are also subject to CEA antifraud provisions. Multilateral natural gas derivatives traded on an electronic exchange are subject to both the antimanipulation and antifraud provisions.

legally permitted. For example, the Intercontinental Exchange, an OTC multilateral energy derivatives trading facility, has a clearing service. NYMEX also clears OTC energy derivatives.

During the natural gas price spike of 2000-2001, CFTC, consistent with its lack of general regulatory authority, did not monitor or assess activity in the OTC markets. However, during congressional testimony in March 2002, CFTC Chairman Newsome confirmed that CFTC was among the federal agencies investigating Enron. Subsequently, in May 2002, responding to widely publicized concerns about wash trading in gas and power markets, Chairman Newsome stated that CFTC was investigating various energy trading schemes, including possible wash trading, in these markets. However, CFTC, consistent with agency policy, would not discuss the nature or extent of its ongoing investigations. As a result, the scope of its investigations and the authority upon which they are being undertaken is unknown.

Further, it remains unclear what information CFTC may rely upon, conclusions it may draw, or enforcement or other actions it may take in relationship to the role the OTC markets may have played, if any, in the natural gas price spike of 2000-2001. However, in October 2002, the CFTC Chairman said that the agency's investigations, in addition to leading to formal actions, might reveal facts that cause CFTC to revisit its rules or to suggest legislative changes.

EIA Is Trying to Modernize Outdated Data Collection Program

EIA—the federal agency responsible for analyzing energy price movements—reports that its ability to understand the market price of natural gas has declined significantly, largely because most elements of its data collection program for the industry were set in place before the industry's restructuring. Most elements of EIA's natural gas data collection program have been in place for more than 20 years, when pipelines and local distribution companies owned the natural gas in their custody and knew its purchase and sales price. In that environment, EIA designed its data collection program to survey a relatively small number of firms to obtain a complete picture of the industry. Today, pipeline and distribution companies do not know the prices of the gas they transport for others, and most industrial and commercial gas is priced in unreported private deals. In addition, entities that did not exist a decade ago—marketers, independent storage facilities, spot markets, and futures markets—are central to the operation of the industry. Because of these changes in the industry, the data collected under EIA's outdated approach have come to describe only a portion of the industry.

EIA has recognized that its collection of data on prices and volumes needs to be timelier because the natural gas market is no longer based solely on long-term contracts. With some exceptions, EIA's current natural gas data collection program remains basically an annual effort to obtain comprehensive information on natural gas volumes and prices. Monthly data series are less complete and the largest monthly survey is a sample survey selected from respondents to the core annual survey. In response to the problems in data coverage and quality, EIA began a review in 1998, called the Next Generation Natural Gas Initiative, to assess the effect of industry restructuring and shifting customer needs on its future natural gas information program. This review includes efforts to identify data quality problems in EIA's current price and volume series as well as requirements for new kinds of data. After a period of public comment in March of this year, EIA submitted a proposal to the Office of Management and Budget for its review that would update EIA's natural gas data collection program package. EIA expects OMB to make final approval of changes to EIA's information program in December 2002, so that the changes take effect in January 2003.

In addition, EIA has recently began to provide more real time market information that traders and other gas industry analysts use as an indicator of both supply and demand. On May 9, 2002, EIA began releasing weekly estimates of natural gas in underground storage for the United States and three regions of the United States—a key predictor of future natural gas price movements. EIA began this weekly estimate because AGA discontinued its own estimate of natural gas in storage, with its final weekly report dated May 1, 2002. EIA has also undertaken efforts to better understand derivatives markets. In February 2002, the Secretary of Energy directed EIA to report on, among other things, how derivatives are being used and to discuss the impediments to the development of energy risk management tools. A draft EIA report, scheduled for release in December 2002, states that, when properly used, derivatives are generally beneficial in managing risk. EIA concluded that all available evidence indicates that the oil industry in particular, and the natural gas industry to a lesser extent, has successfully used derivatives to manage risk. However, EIA found that continuing problems with the reporting of natural gas price data and with pipeline transmission costs might be denying the benefits of derivatives to many potential users.

Consumers Can Be Protected against Price Spikes

Residential customers who rely on natural gas to heat their homes are especially vulnerable to price spikes because they may have limited ability to switch to alternate fuels for heating their homes or to obtain gas from sources other than the gas utility companies. Therefore, when the gas utilities pay higher wholesale prices for natural gas, residential customers usually see their heating costs increase as well. This is true because a majority of gas utility companies, under state or local regulatory oversight, pass their gas costs on to their customers. However, utility companies can use various techniques to protect or hedge against the risk of rising natural gas costs by locking in the prices they will pay for gas purchased for residential customers. Hedging does not, however, ensure that a utility company will pay the lowest possible price for future natural gas purchases: it simply provides stable gas prices and protection against price spikes such as the one that occurred in 2000-2001. Hedging may result in the utility company paying natural gas prices that are higher or lower than the prevailing market price. In the 5 years prior to the recent price spike, between 20 percent of the small and 45 percent of the large gas utility companies responding to our survey reported that they did not hedge any of their natural gas purchases. Further, industry data that we reviewed showed that prior to and during the winter of 2000-2001, many gas utility companies were relying more on shorter-term contracts and the more expensive spot market for the gas they were purchasing to satisfy customer needs throughout the winter heating season. As a result, a significant number of gas utilities likely had to pay higher prevailing market prices when they purchased the natural gas needed to satisfy their customers' needs in 2000-2001, and these higher prices were likely passed on to their customers. This recent price spike increased the importance of price stability for those gas utilities that serve residential customers and the regulatory agencies that oversee this service. As a result of the 2000-2001 price spike, gas utilities have increased their use of hedging when buying natural gas. Ninety percent of the utilities responding to our survey reported that after the price spike they made plans to hedge some portion of their gas supply for the winter of 2001-2002.

Various Tools Are Available to Protect against Rising Gas Prices

Gas utilities can use several hedging techniques to stabilize their gas supply costs and thereby protect their customers against the unpredictable price behavior of natural gas. Hedging techniques include both physical and financial tools. Physical tools, which are widely used by gas utilities, include the following:

- Storage of gas for future use can provide a hedge against the effects of price volatility. According to industry officials, many gas utility companies have traditionally purchased a portion of their gas supply during the warmer summer months when prices are lower and stored the gas for use during the winter heating season when prices are typically higher. However, there are costs associated with storing natural gas and, because it is stored underground in geologic formations, such as salt caverns, and in depleted oil and gas wells located in 30 states, not all gas utility companies can take advantage of this tool.

- Fixed price contracts, or forward contracting arrangements, can also provide a hedge against price volatility. Under such an arrangement, a utility agrees to take delivery of a set amount of natural gas at a specified time, price, and location. However, the buyer must pay the contract price even if the market price at the time of purchase is lower.

For those gas utility companies that cannot or do not want to rely on physical hedges, various derivatives can also provide protection against increasing gas prices. Derivatives are contracts whose value is linked to, or derived from, the price of the gas itself. There are costs associated with using all derivatives, but most of the state regulatory agencies we surveyed allow gas utilities to recover these costs through their gas rates. Derivatives include natural gas futures, options, and swaps.

- Futures contracts that are traded on regulated exchanges, such as NYMEX generally are standardized. A gas utility that purchases a futures contract or an options contract through NYMEX is protected against counterparty credit risk. Simply stated, the financial performance of both the buyer and the seller of futures and options are guaranteed by the exchange. A natural gas futures contract may be purchased to lock in a future price for up to 72 months in the future and natural gas options can be used to guarantee prices in increments of $0.05 per mmBtu for various time periods. For example, a purchaser of a futures contract traded on NYMEX makes a legal commitment to take delivery of 10,000 mmBtu of gas at the Henry Hub in Louisiana on a specified date in the future. However, hedgers who buy futures contracts usually do not take delivery of the gas. According to a NYMEX official, less than 1 percent of the gas futures contracts traded on the exchange result in physical delivery of the commodity. Instead, those holding futures typically sell the contracts through NYMEX before the contractual date of delivery at the going market price. Then, whatever profit or loss accrues from this transaction offsets the change in natural gas prices from the time they bought the contract to when they buy gas for delivery. For example, in March a gas utility company wishing to hedge against a possible future price increase buys a futures contract for gas to be delivered in January at $4.60. If the January cash price later increases to $5.15, the company can buy its gas on the spot market for $5.15 and sell the futures contract on NYMEX for $5.15 thereby accruing a gain of $.55 on the futures contract and a net gas cost of $4.60. If, however, the January cash price drops to $4.25, the company could buy its gas at this price, sell the futures contract at $4.25 and take a loss of $0.35. But, the company's net gas cost would still be $4.60.

- Options, which can be bought for a premium on NYMEX or in the OTC markets, give a utility the right, but not the obligation, to buy or sell natural gas at a certain price at some time in the future. Some analysts believe that purchasing options is the best way for gas utility companies to hedge against possible price increases, because the utility holding an option is protected against possible increases in the price of gas, but at the same time has the ability to participate in any downward changes in price.
- Swaps generally provide more flexibility to users than do exchange-traded futures because their terms can often be individually negotiated, such as for different amounts of gas and for different delivery points. However, natural gas swaps are traditionally traded in the OTC markets, and these markets often do not provide the same level of protection against credit exposure as NYMEX.

Hedging Does Not Guarantee the Lowest Possible Gas Prices

A gas utility company that follows a hedging strategy is not guaranteed that it will pay the lowest price for natural gas. In fact, minimizing price volatility through hedging and minimizing gas costs (beating the market) are two entirely different objectives. A hedging strategy for a gas purchaser aims at gaining more certainty with respect to future costs, or avoiding exposure to large price fluctuations in the future that could come from total reliance on spot market prices. This is a different strategy from one that tries to secure the lowest possible prices in the future. Neither strategy is costless, and parties that use them risk that their effective costs, after the fact, may be higher than those of alternative strategies.

To show how a hedging strategy can result in prices that are lower or higher than spot market prices, we conducted an analysis based on a hypothetical utility and actual spot and futures gas prices.

- We constructed a hypothetical gas utility, GU-H, whose gas use patterns mirror, on a smaller scale, the pattern of residential gas consumption in the United States from 1990 through 2001. We modeled GU-H so that its gas requirements each month are equal to about 2.5 percent of residential gas consumption in the United States. This makes GU-H a fairly large gas utility.

- We assumed that GU-H follows a hedging strategy whereby it purchases NYMEX gas futures contracts for the months of November through March–the months for which it has the highest gas requirements during the year.
- We assumed GU-H purchases the same amount of NYMEX contracts for each month of the winter season every year, based on its estimate of "baseload" for that month. We assumed that its baseload estimate is equal to the lowest amount of gas used for that month from 1990 through 2001. For example, the lowest amount of gas GU-H used during the month of January was in 1992 at slightly under 20 bcf, so we assumed that GU-H hedges this amount for the month of January each year.
- We assumed GU-H effectively "locks-in" prices for the coming November through March by purchasing NYMEX gas futures contracts on the first trading day in April of each year. For example, on April 3, 2000, GU-H purchased NYMEX gas contracts for the months of November and December 2000 and January through March of 2001.
- We assumed a transactions cost for the NYMEX contracts based on conversations with NYMEX officials. This cost was added to the hedged cost of gas, but it is relatively small.
- We assumed that monthly amounts of natural gas used above the baseload amounts covered by the futures contracts were bought on the spot market at a price indexed to a monthly average spot price at the Henry Hub, effectively resulting in zero transmission costs, another simplifying assumption.

Given the above, we compared the cost of GU-H's gas purchases for the winter months of November through March with and without a hedging strategy. Without hedging, GU-H purchases all its gas requirements on the spot market at the monthly spot price. Table 1 summarizes the results of our analysis with respect to GU-H's gas purchase costs from the 1990-1991 winter through the 2001-2002 winter.

Table 1: Results of a Hypothetical Gas Utility (GU-H) Hedging Gas Purchases Versus Relying on Spot Market Prices for Winters 1990 through 2001

Dollars in millions

	Winter Heating Season (November through March)											
	90-91	**91-92**	**92-93**	**93-94**	**94-95**	**95-96**	**96-97**	**97-98**	**98-99**	**99-00**	**00-01**	**01-02**
Unhedged gas costs	$136.8	$120.6	$175.2	$202.1	$122.5	$270.4	$275.3	$205.6	$152.2	$201	$644.3	$192.1
Hedged gas costs	155.1	156.4	153.5	193.9	179.4	196.1	209.6	195.7	214.3	195.2	368.7	412.7
Hedging gain (loss)	(18.3)	(35.8)	21.7	8.2	(56.9)	74.3	65.7	9.9	(62.1)	5.8	275.6	(220.6)

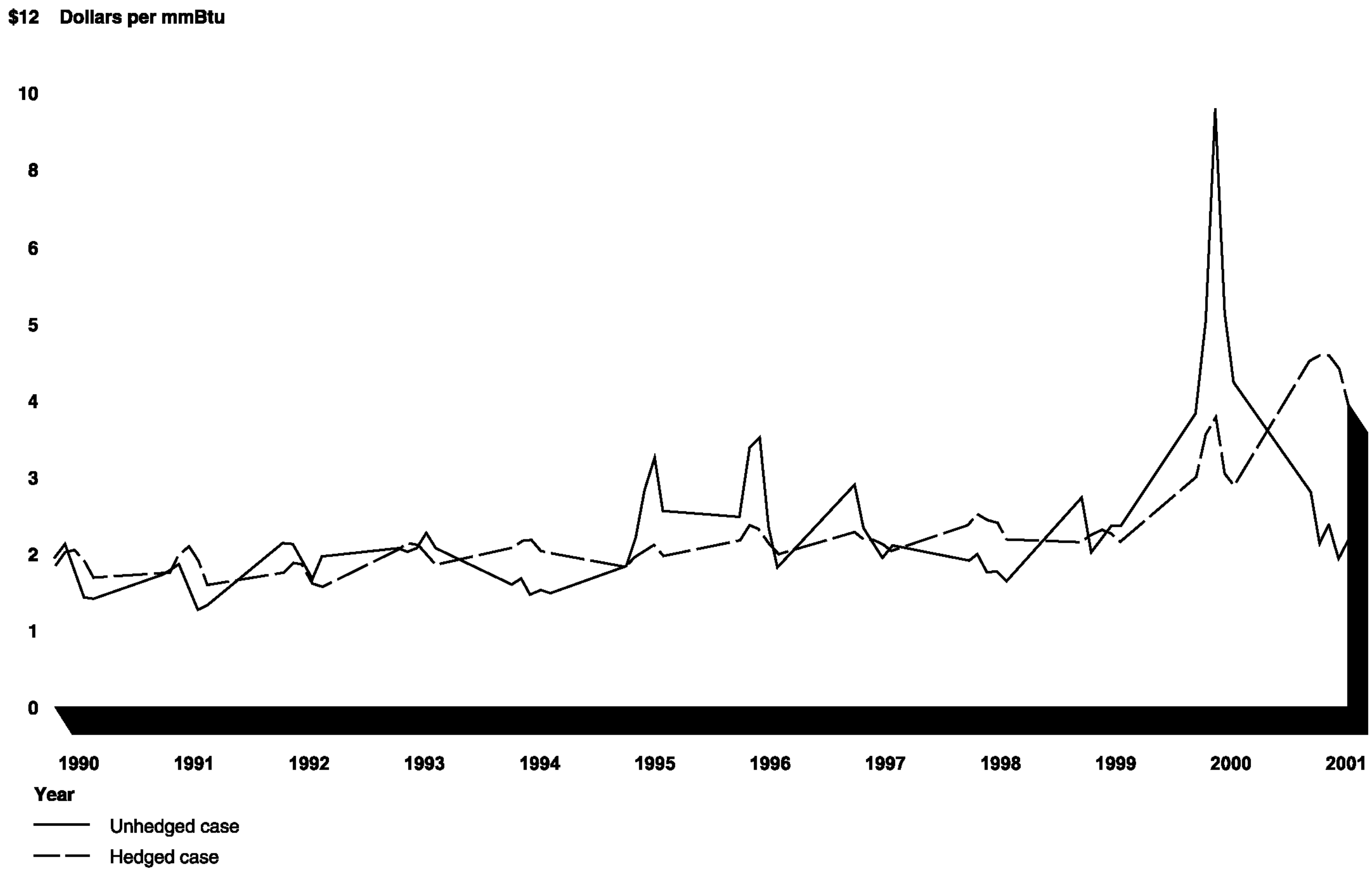
Source: GAO analysis of EIA, NYMEX, and other data.

As the table shows, GU-H's hedging strategy would have resulted in net savings over the spot market price in gas purchase costs for some winter seasons and losses for others. For the winter of 2000-2001, the savings would have been unusually large—over $275 million—because spot market prices turned out to be far higher than NYMEX futures prices. However, the very opposite would have been the case in the winter of 2001-2002, when GU-H's losses would have been over $220 million.

We also calculated the effective monthly prices for the winter months with and without hedging. Interestingly, over the 11-year period, the overall average price paid for gas under the two scenarios was virtually the same, at about $2.56 per mmBtu for the unhedged case and $2.57 per mmBtu for the hedged case.[15] However, the level of volatility was greater for the unhedged case. According to one commonly used measure of deviation from averages (standard deviation), the hedged case resulted in considerably less exposure to price volatility than the unhedged case. A measure of dispersion from the average price was about $1.41 for the unhedged case and only about $0.97 for the hedged case. Figure 10 shows a comparison of hedged and unhedged gas prices for a hypothetical gas utility.

[15]These are simple averages in the sense that they are not "weighted" by the quantities of gas purchased/delivered for the individual months.

Figure 10: Comparison of Hedged and Unhedged Gas Prices for Hypothetical Gas Utility



Source: GAO analysis.

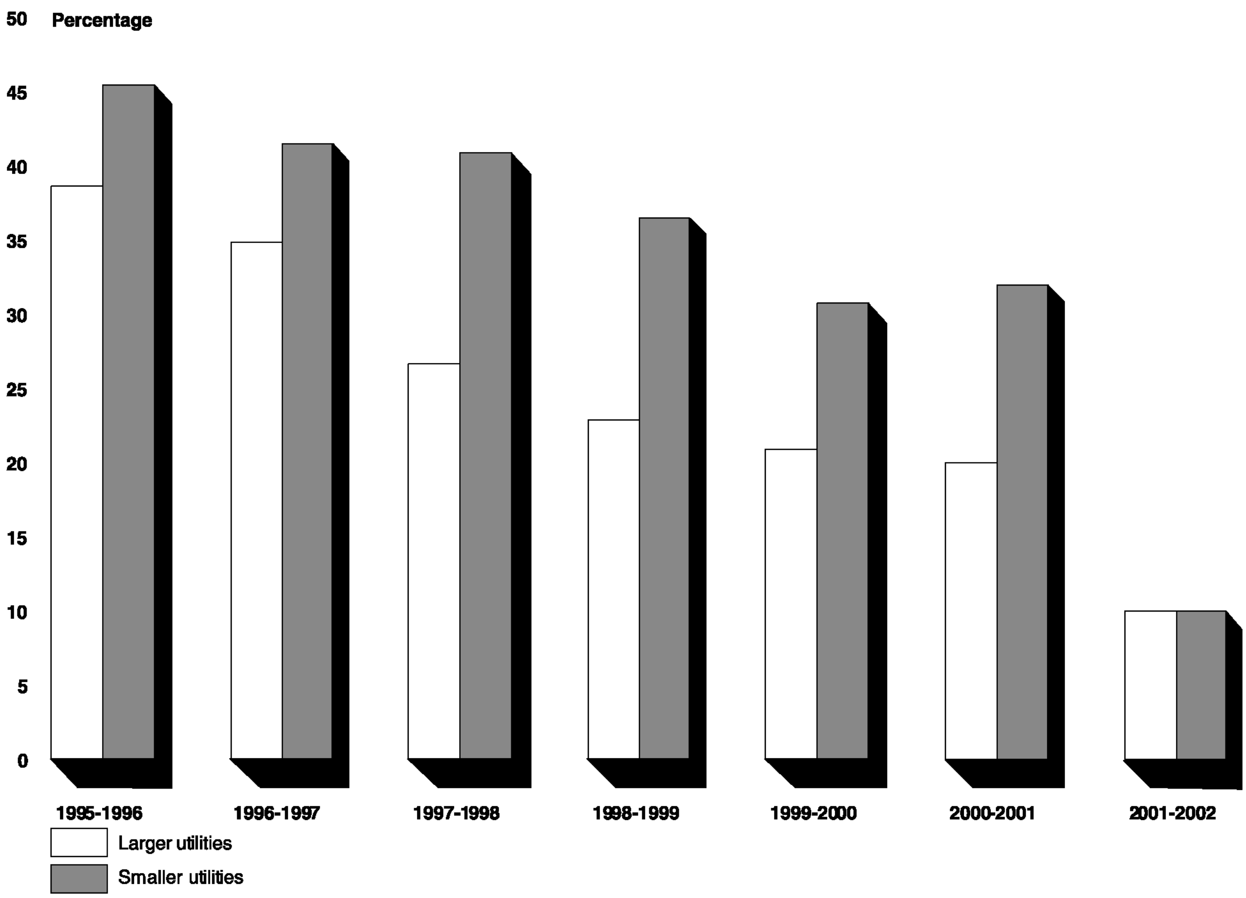
Note: Figure 10 plots average prices for November through March for the hypothetical gas utility GU-H.

Prices in 2000-2001 Prompted Gas Utilities and State Regulatory Agencies to Act to Mitigate Future Price Spikes

Following the price spike in 2000-2001, many gas utilities took steps to protect themselves and their customers against a repeat of the soaring prices that marked that period. According to our survey, since the natural gas price spike in 2000-2001, many gas utilities have increased their focus on achieving stable prices for their customers. In fact, 87 percent of the small utilities and 74 percent of the large utilities responding to our survey reported this goal is very important or extremely important to them. Previously, only 72 percent of the small utilities and 48 percent of the large utilities thought that stable prices were very important or extremely important. In addition, the efforts of utilities to provide more stable prices for their customers have received more support from state regulatory agencies. For example, state regulatory officials from 29 of the 48 agencies that we spoke with told us that they consider it very important or extremely important for gas utility companies to work toward achieving stable prices for their residential customers. Before the gas price spike in 2000-2001, only 14 agencies surveyed had considered this goal to be very important or extremely important.

Consistent with the increased importance of stable prices, many gas utilities increased the percentage of their gas supply that they hedged after the winter price spike of 2000-2001. During the 2000-2001 winter, 20 percent of the large utilities and 32 percent of the small utilities that responded to our survey did not hedge any of their winter gas supply for residential customers. As a result, these utilities had to pay the prevailing high spot market prices for gas, resulting in higher bills for their customers. In contrast, during the 2001-2002 winter, only 10 percent of these utilities did not hedge any of their winter gas supply for residential customers. About 63 percent of the large utilities and 81 percent of the small utilities that responded to our survey reported that they hedged at least one-half of their winter gas supply during 2001-2002. In comparison, during the previous year, about 44 percent of the large utilities and 56 percent of the small utilities hedged at least one-half of their gas supply. In addition, a recent survey of 52 companies completed by AGA found that a majority of them planned to increase their use of hedging techniques to protect at least part of their gas supply portfolios from future price spikes. According to an AGA official, the extreme price volatility experienced during the winter of 2000-2001 made it clear to many gas utilities that hedging a portion of their gas supply helped to shield their customers from dramatic increases in natural gas prices. As figure 11 shows, since 1995, the number of utilities that do not hedge any of their gas supply for residential customers has steadily decreased.

Figure 11: Percentage of Gas Utilities That Hedged None of Their Winter Gas Supply for Residential Customers, 1995-2002



Source: GAO analysis of survey data.

Many gas utility companies continued to use fixed price contracting and storage as the primary tools for stabilizing their gas acquisition costs. However, some gas utilities also used derivatives, including futures, options, and swaps, as a way of stabilizing their gas costs. Table 2 shows that the gas utility companies that responded to our survey used physical hedging tools much more than derivatives, and large utilities reported much higher use of financial hedging techniques than small utilities.

Table 2: Percentage of Gas Utility Companies That Reported Using Hedging Techniques in Gas Purchases for 2000-2001

Hedging techniques	Large utilities (percentage)	Small utilities (percentage)
Physical tools		
Storage	84	49
Fixed price contracts	56	65
Financial tools		
Futures	35	24
Options	36	4
Swaps	28	5

Source: GAO analysis of survey data.

Overall, 57 percent of the large gas utility companies and 47 percent of the small gas utility companies responding to our survey reported that they had increased their use of one or more hedging techniques since the 2000-2001 winter. Table 3 shows the specific changes in the use of different hedging techniques among the utility companies. More details on the gas utilities' responses to our survey questions can be found in appendixes II and III.

Table 3: Changes in Utilities' Use of Hedging Techniques since Winter of 2000-2001

	Percentage using hedging technique			Percentage not currently using hedging technique	
	Use has increased	Use has remained the same	Use has decreased	Plan to use in the next 12 months	Do not plan to use in the next 12 months
Large utilities					
Physical tools					
Storage	**13**	**72**	**0**	**2**	**13**
Fixed price contracts	**42**	**36**	**2**	**5**	**14**
Financial tools					
Futures	**23**	**29**	**2**	**8**	**38**
Options	**20**	**30**	**5**	**9**	**36**
Swaps	**18**	**30**	**1**	**7**	**43**
Small utilities					
Physical tools					
Storage	**9**	**51**	**0**	**3**	**37**
Fixed price contracts	**34**	**42**	**4**	**6**	**15**
Financial tools					
Futures	**22**	**19**	**1**	**5**	**52**
Options	**5**	**13**	**2**	**5**	**75**
Swap	**3**	**17**	**1**	**1**	**79**

Source: GAO analysis of survey data.

According to our survey of state regulatory agencies, most allow the gas utilities under their jurisdiction to use hedging techniques when they purchase gas for their residential customers. However, despite an increasing openness to the idea of hedging tools, these regulatory agencies favored the use of physical hedging tools over financial tools. Table 4 reflects the positions of state regulatory agencies on the use of hedging tools by the gas utilities they regulate.

Table 4: State Regulatory Agency Policy Concerning Gas Cost Stabilization Tools

Cost stabilization tool	Number of state agencies allowing use of the tool	Number of state agencies not allowing use of the tool	Does not apply[a]	No response
Physical tools				
Storage	45	0	3	0
Fixed price contracts	45	0	3	0
Financial tools				
Futures	42	1	5	0
Options	40	3	5	0
Swaps	36	1	10	1

Note: We surveyed the 48 continental states and the District of Columbia. The Nebraska Public Service Commission declined to respond because natural gas is regulated on a local level and the Commission handles only pipeline disputes.

[a]Either the tool is not available in a certain area or the agency has not addressed the tool in its policy.

Source: GAO analysis of survey data.

In general, state regulatory agencies that allow gas utilities to use hedging tools do not restrict the amount of gas purchased through use of these tools. In addition, a large percentage of the gas utilities responding to our survey reported that their regulatory agency allows them to recover all costs associated with hedging. And, while 90 percent of the utilities regulated by state agencies reported being subject to prudence audits of their gas-buying strategy, only 7 percent have had costs associated with gas purchases disallowed by an agency because of such an audit. More details concerning the state regulatory officials' responses to our survey questions are shown in appendixes IV and V.

Conclusions

Although the federal government is not a direct regulator of natural gas prices, it has an interest in promoting a competitive and informed natural gas marketplace that protects the public from unnecessary price volatility. The principal tools available to federal agencies to promote a competitive natural gas marketplace and protect the public from price volatility include monitoring for anticompetitive behavior; taking appropriate enforcement actions where necessary; and providing decision-makers in industry and government with sound, up to date, natural gas marketplace information, such as short-term price movements and long-term demand and supply trends. However, at this date, the federal government faces major challenges in meeting its role of ensuring that natural gas prices are determined by supply and demand factors in a competitive and informed marketplace.

We had previously recommended that FERC take actions to update its strategic plan and to develop an action plan for overseeing energy markets, so that it could more effectively carry out its responsibilities for overseeing interstate wholesale natural gas and electricity markets. We continue to believe these steps are important and are encouraged that FERC is beginning actions to address this recommendation. FERC recognizes that it needs to improve its market oversight and is reviewing its statutory authority and market monitoring tools. In addition, we suggested and continue to believe that the Congress might wish to convene public hearings to review FERC's authorizing legislation and determine, in consultation with FERC Commissioners, whether FERC's authorities need to be revised in light of the changing energy markets. Of particular concern would be any changes needed to support FERC's new Office of Market Oversight and Investigation. CFTC, consistent with its authority, did not monitor activity in the OTC markets during the winter of 2000-2001, but it is continuing its investigation into whether OTC energy derivatives markets were manipulated during this period. Findings from these investigations may lead to enforcement actions and may also highlight the need for changes in federal oversight. Finally, EIA has recognized the need to collect more accurate and timely data on the natural gas market and has begun taking steps to update its data collection program for natural gas. We support these efforts and believe it is important that the agency continue to refine its efforts to provide more timely natural gas market data and focus on implementing changes to its natural gas data collection program as soon as possible.

Agency Comments

We provided FERC, EIA, and CFTC with a draft of this report for review and comment. FERC generally agreed with our conclusions (see app. VI), and noted that it previously lacked an adequate regulatory and oversight approach to monitor a restructured natural gas industry. FERC stated that with the creation of its Office of Market Oversight and Investigation it has taken the steps needed to oversee and assess the fair and efficient operation of electric power and natural gas markets. In addition to its letter, FERC provided us with technical changes to our draft, which we incorporated into the final report as appropriate. EIA generally agreed with our conclusions (see app. VII), and noted that it recognized the need to collect more accurate and timely data on the natural gas market and has begun taking steps to update its data collection program for natural gas. In addition to its letter, EIA provided us with technical changes to our draft, which we incorporated into the final report as appropriate. CFTC did not provide us a formal letter, but met with us to provide us with technical changes, which we incorporated into the report as appropriate. It also generally agreed to our conclusions.

Copies of this report will also be sent to the FERC Chairman, the CFTC Chairman, the DOE Secretary, and other interested parties. We will make copies available to others upon request. In addition, the report will be available at no charge at GAO's Web site at http: www.gao.gov.

Questions about this report should be directed to me at (202) 512-3841. Key contributors to this report are listed in appendix VIII.

Jim Wells
Director, Natural Resources
and Environment

List of Addressees

The Honorable Jeff Bingaman
Chairman
The Honorable Frank Murkowski
Ranking Minority Member
Committee on Energy and Natural Resources
United States Senate

The Honorable Joseph I. Lieberman
Chairman
The Honorable Fred Thompson
Ranking Minority Member
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The Honorable Tom Harkin
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The Honorable Spencer Bachus
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The Honorable Bob Clement
The Honorable Bud Cramer
The Honorable Bob Etheridge
The Honorable Bart Gordon
The Honorable Edward J. Markey
The Honorable Janice D. Schakowsky
The Honorable John M. Spratt, Jr.
The Honorable John Tanner

The Honorable Mike Thompson
The Honorable Zach Wamp
House of Representatives

Appendix I: Objectives, Scope, and Methodology

In our study of the natural gas market, we addressed (1) the factors that influence price volatility and, in particular, the high prices that occurred during the winter of 2000-2001; (2) the federal government's role in ensuring that natural gas prices are determined in a competitive and informed marketplace; and (3) choices available to gas utility companies that want to mitigate the effects of future price spikes on their residential gas customers.

To address these objectives, we reviewed pertinent documents and obtained information and views from a wide range of officials in both government and the private sector. Our review encompassed the entire natural gas market from the wellhead, where gas is produced and first valued, to the end-user. We obtained information and views from federal, state, and local agencies and from natural gas industry officials through a variety of means, including interviews and surveys. We interviewed analysts from the Department of Energy's Energy Information Administration (EIA), the Federal Energy Regulatory Commission (FERC), the Commodity Futures Trading Commission (CFTC), the New York Mercantile Exchange (NYMEX), companies involved in over-the-counter gas markets, such as the Intercontinental Exchange, and state utility regulatory commissions, to obtain their views on the factors that influence natural gas prices. We also discussed natural gas prices with representatives from various industry organizations, including the American Gas Association (AGA), the American Public Gas Association (APGA), the National Association of Regulatory Utility Commissioners (NARUC), the National Association of State Utility Consumer Advocates, the Natural Gas Supply Association, the Independent Petroleum Association of America, and the Interstate Natural Gas Association of America. Finally, we spoke with various individuals who work in the natural gas industry, including experts working at production companies, gas marketing companies, and gas utilities.

In addition to our interviews, we obtained and analyzed natural gas price data supplied by the EIA, Data Resources, Incorporated (DRI), and NYMEX. The EIA provided wholesale gas prices, city gate prices, and end-user prices by customer class and by state, while the DRI database provided prices for the Henry Hub spot market prices and NYMEX officials provided prices for NYMEX natural gas futures contracts. Our analyses focused on how gas prices have behaved since 1993, when natural gas wholesale prices became fully deregulated. We also collected and analyzed data on factors that influence natural gas supply and demand, such as production, storage, consumption, weather, and gas-fired electric generation, as well as data on natural gas derivatives trading.

Because residential customers usually have limited ability to switch to alternate fuels and few choices concerning who will supply their natural gas, we concentrated on determining how high prices affected this group of end users and what gas utilities can do to protect them from future price spikes.

We also reviewed laws and regulations pertaining to CFTC's, EIA's, and FERC's responsibilities for monitoring and providing information about the natural gas market. In addition, we identified key changes in natural gas regulation and in the development of the natural gas market that changed how gas prices are established. We also examined pertinent CFTC, EIA, and FERC documents, including annual reports and filings, staff research papers, fact sheets, reports, and congressional testimonies.

We surveyed a sample of both investor-owned and municipally-owned gas utility companies to determine how they acquire their natural gas and what actions they have taken or plan to take to mitigate the effects of future price spikes. We identified our sample primarily from the lists of member utilities belonging to the AGA and the APGA. The AGA generally represents larger, investor-owned gas utilities; whereas, the APGA generally represents smaller, municipal gas utility companies. Since some companies were members of both organizations, we adjusted our sample by removing duplicates from the APGA list. We also included in our survey four large gas utility companies, which were identified by AGA staff as major utilities that are not members of their organization. Thus, our overall population consisted of all gas utility companies in the United States that were members of either the AGA or APGA, plus four additional companies.

We sent survey questionnaires to the 112 gas utilities on AGA's membership list, plus the 4 large investor-owned utilities that are not members of the AGA. In addition, we selected 17 large municipal utilities from APGA's members list of 923 utilities for inclusion in our survey. Each of these 17 companies reported that it serves more than 20,000 customers. Thus, the first group of gas utilities we surveyed, referred to as the AGA group, consisted of 133 companies that serve large customer bases and deliver a large majority of the total volume of natural gas sold in this country. According to AGA, their members plus four additional large companies account for more than 90 percent of the natural gas delivered by gas utilities annually in the United States. We then selected a statistical sample from the remaining 906 (923–17) municipally-owned gas utilities found on the APGA members list. Our sample consisted of 342 municipal utilities, which provided 95 percent confidence intervals of +5 percentage points. Thus, our second group of gas utilities, referred to as the APGA group, consisted of 342 municipal companies that tend to have smaller customer bases. Before mailing our survey questionnaire to the two groups, we pretested it at six utility companies across the country that serve a range of customers. During these visits, we administered the survey and asked the utility staff to fill out the survey as if they had received it in the mail. After completing the survey, we interviewed the respondents to ensure that (1) the questions were clear and unambiguous, (2) the terms we used were precise, (3) the questionnaire did not place an undue burden on the staff completing it, and (4) the questionnaire was independent and unbiased.

We did not receive a high enough response rate to our survey of gas utility companies to allow us to generalize the results of our analysis to all gas utilities located in the United States. We did, however, receive responses from 90 or 68 percent of the 133 companies in the first group (AGA list) and 179 responses or 52 percent of the 342 companies in the second group (APGA list). Because we cannot generalize the results of our survey, we have reported the results from the two groups–large utilities (AGA) and small utilities (APGA)–separately.

We also surveyed staff from the utility regulatory agencies of the 48 contiguous states and the District of Colombia. We did not include Alaska and Hawaii in our survey, as these states are unique in their use of natural gas because their geographic locations separate them from the rest of the country's natural gas infrastructure. We pretested our questionnaire with the regulatory agencies in Maryland, New Mexico, and the District of Columbia and then completed a structured interview with staff from the 48 states and the District of Colombia. However, because the Nebraska Public Service Commission does not regulate gas utility companies (such regulation occurs at the local government level), we exempted this state from our analysis of regulatory agencies. To identify the most qualified person within the agencies to contact, we obtained a list from NARUC, whose members include the governmental agencies that are engaged in the regulation of utilities and carriers of telecommunications, energy, and water. In cases where NARUC was unable to provide a contact, we called the agency directly.

We performed our review from June 2001 through September 2002 in accordance with generally accepted government auditing standards. However, we were unable to assess the accuracy of the natural gas prices and other information provided by the EIA or the DRI database, as no resources exist to verify this data.

Appendix II: Results of Investor-Owned and Municipally Owned Utility Survey

We mailed a questionnaire to 475 from a population of 1,039 gas utilities in the continental United States. The questionnaire, reprinted below, contained 33 questions covering the utility's basic characteristics, gas purchasing strategy for residential customers, use of hedging tools, and regulatory framework.

In the following results we provide statistics for our two sampling groups. We identified these groups primarily from the lists of member utilities belonging to AGA and APGA. The first group consists primarily of AGA members, which are generally large, investor-owned gas utilities. This group also includes four large investor-owned utilities identified by AGA staff as the investor-owned utilities that did not belong to their organization, as well as the 17 companies on the APGA list that reported serving more than 20,000 natural gas customers. For simplicity, in the results we refer to this group as AGA. The second group consists of a sample of the APGA mailing list, which tend to be small, municipally owned gas utilities. In the results we refer to this group as APGA. We received responses from 269 utilities; 90 from AGA members for a response rate of 68 percent and 179 from APGA members for a response rate of 52 percent.

For most of the questions of the reprinted survey, we identified the percent of utilities that marked each box to each question. For other questions, we included tables of the responses in appendix III and referred the reader to these tables. For the questions on population, we included the mean, median and range of responses. Also, several gas utilities did not respond to each question, so some questions have fewer total respondents than others. We included the number of respondents to each question, with N referring to the total number of respondents that answered a question and n referring to the number of respondents that indicated a certain answer to a question.

U.S. General Accounting Office

Survey of Investor-Owned and Municipally-Owned Utilities

Introduction

The Congress has asked the U.S. General Accounting Office to review various issues surrounding the pricing of natural gas, given the high prices during the winter of 2000-01. As part of this review, we are conducting a survey of a statistical sample of gas utility companies. The purpose of this survey is to collect information on the strategies and techniques these companies use when purchasing natural gas for on-system residential customers. In addition, we are surveying the public utility commissions of the 48 contiguous states and the District of Columbia. The purpose of this survey is to collect information on how utility companies purchase natural gas, from the standpoint of both regulation and oversight.

We understand that there are many demands on your time; however, because your utility company is part of a statistical sample, your participation in this survey is critical to our providing complete and balanced information to the Congress. We will use this information to help the Congress better understand the natural gas market. Specifically, we will present a report based on our analysis. The report is scheduled to be issued in the summer of 2002.

Instructions

Please complete the questionnaire and return it, within 10 days of receipt, to the address below.

When reviewing these questions, we ask that you coordinate with appropriate members of your utility company, that is, those responsible for the development and implementation of your gas-purchasing strategy. If you contract with an organization—a third party or aggregator—for assistance with the purchasing of your natural gas, please feel free to consult with that organization as well.

We have provided a postage-paid business reply envelope to facilitate the return of your questionnaire. If the return envelope is misplaced, please send or fax your completed questionnaire to:

U.S. General Accounting Office
Attention: James Cooksey
1999 Bryan Street, Suite 2200
Dallas, TX 75201-6848

FAX #: 214- 777-5758

If you have any questions, please call
Mark Gaffigan
202-512-3168
(e-mail gaffiganm@gao.gov)

or

James Cooksey
214-777-5687
(e-mail cookseyj@gao.gov)

Thank you for your help!

1. For the fiscal years below, how many residential natural gas customers—both total (including distribution and on-system sales) and on-system only—did your utility serve? *(Enter number; if none, enter '0'.)*

	Residential Customers - AGA				
	Total				On-system
1995	Mean: 299,851	Median: 105,434	Range: 1,924-4,504,167	N=84	
1996	Mean: 304,604	Median: 122,400	Range: 1,891-4,556,776	N=85	
1997	Mean: 334,309	Median: 132,584	Range: 1,877-4,559,841	N=85	
1998	Mean: 367,402	Median: 143,885	Range: 1,877-4,658,885	N=86	
1999	Mean: 339,485	Median: 134,400	Range: 1,877-4,731,630	N=87	
2000	Mean: 347,322	Median: 134,099	Range: 1,884-4,800,643	N=87	
2001	Mean: 374,930	Median: 138,980	Range: 1,895-4,860,182	N=87	

	Residential Customers – APGA				
	Total				On-system
1995	Mean: 2,077	Median: 1,011	Range: 0-17,370	N=147	
1996	Mean: 2,141	Median: 1,017	Range: 0-17,825	N=155	
1997	Mean: 2,147	Median: 1,000	Range: 0-18,074	N=162	
1998	Mean: 2,454	Median: 1,014	Range: 66-19,060	N=164	
1999	Mean: 2,265	Median: 1,053	Range: 66-19,492	N=165	
2000	Mean: 2,295	Median: 1,000	Range: 66-19,900	N=169	
2001	Mean: 2,431	Median: 1,000	Range: 66-20,794	N=168	

2. How important, if at all, are the following pricing goals for your gas utility company to consider when purchasing natural gas for on-system residential customers? *(Check one for each pricing goal.)*

Pricing Goal	Slightly or not important	Somewhat important	Moderately important	Very important	Extremely important	N=
1. Stable prices						
AGA	0%	7%	19%	47%	27%	89
APGA	1%	1%	10%	44%	43%	176
2. Lowest reasonable price						
AGA	0%	2%	20%	36%	42%	89
APGA	1%	1%	14%	34%	51%	177
3. Prices close to the market						
AGA	2%	10%	34%	38%	16%	89
APGA	3%	8%	28%	38%	23%	168
4. Other (Please specify.)						
AGA						20
APGA						9

3. Has the importance of any of these pricing goals changed since 1995?

 1. [ ] No **AGA: 53%, n=46 APGA: 68%, n=117**

 2. [ ] Yes → **AGA: 47%, n=41 APGA: 32%, n=56**

  a. When did it change? → ______________________
  AGA: 66%, N=41, indicated 2000-2001
  APGA: 79%, N=56, indicated 2000-2001

  b. Prior to this change, how important, if at all, were the following pricing goals for your gas utility company to consider? *(Check one for each pricing goal.)*

	Slightly or not important	Somewhat important	Moderately important	Very important	Extremely important	N=
1. Stable prices						
AGA	12%	32%	37%	17%	3%	41
APGA	4%	14%	38%	20%	25%	56
2. Lowest reasonable price						
AGA	0%	5%	24%	34%	37%	41
APGA	2%	7%	23%	36%	32%	56
3. Prices close to the market						
AGA	8%	3%	18%	52%	20%	40
APGA	5%	9%	38%	29%	20%	56
4. Other (Please specify.)						
AGA						4
APGA						1

  c. What was the reason for changing the importance of the pricing goals?

  AGA: 67% of those responding (n=33) cited high prices and/or price volatility as a reason behind changing their pricing goals

  APGA: 83% of those responding (n=38) cited high prices and/or price volatility as a reason behind changing their pricing goals

Planned Purchases Of Natural Gas Supply - See table 5 and table 7 in appendix III for question 4 results

4. For each Winter Heating Season (WHS; November 1 – April 1) listed below:

 (A) about how much natural gas did your utility company **plan** to purchase for on-system residential customers during the 1999-2000, 2000-2001, and 2001-2002 Winter Heating Seasons,
 (B) about what percent of natural gas supply did your utility company plan to buy at a price that was **unknown** prior to the beginning of the WHS, and
 (C) about what percent did your utility company plan to buy at a price or price range that was **known** prior to the beginning of the WHS?

Winter Heating Season (Nov 1 to April 1)	(A) **Planned** volume of gas supply purchased for on-system residential customers during WHS (in Mcf)	(B) Prior to the beginning of the WHS, what percent of supply did your utility plan to buy at **an unknown price** ("spot market"). *(Please enter percent; if none, enter '0'.)* Unknown includes: • daily and first of the month spot purchases and • contracts indexed to daily or first of the month prices **(Do not include gas hedged using futures, options, or swaps.)**	(C) Prior to the beginning of the WHS, what percent of supply did your utility plan to buy **at a known price or within a known price range.** *(Please enter percent; if non enter '0'.)* Known includes: • financial hedging instruments (such as futures, options, swaps, or weather derivatives), • fixed price contracts, and • storage	
1995-1996		%	%	=100%
1996-1997		%	%	=100%
1997-1998		%	%	=100%
1998-1999		%	%	=100%
1999-2000		%	%	=100%
2000-2001		%	%	=100%
2001-2002		%	%	=100%

5. If your utility had any significant changes in the percentages of planned "unknown" and "known" gas purchases for on-system residential customers between the Winter Heating Seasons listed above, please indicate the reasons for the changes. *(Check one or more for each. If there was a significant change, please enter the year it occurred.)*

[ ] Not Applicable- no significant change→ **AGA: 36%, n=32 APGA: 35%, n=62**

Checked one or more of the below responses: **AGA: 64%, n=57 APGA: 65%, n=116**	Yes	No	N=		In what year did the change occur?
1. A change in your gas cost recovery method				If yes→	AGA: 33%, n=1
AGA	7%	93%	41		APGA: 73%, n=11
APGA	20%	80%	76		cited 2000-2001
2. Increased price levels or volatility				If yes→	AGA: 85%, n=34
AGA	89%	11%	45		APGA: 75%, n=52
APGA	81%	19%	83		cited 2000-2001
3. A change encouraged or directed by a regulatory body's decision				If yes→	AGA: 64%, n=9 APGA: 64%, n=7
AGA	36%	64%	39		cited 2000-2001
APGA	15%	85%	74		
4. A regulatory or legislative change that allowed more use of cost stabilization tools				If yes→	AGA: 45%, n=5 APGA: 83%, n=5
AGA	27%	73%	41		cited 2000-2001
APGA	8%	92%	74		
5. A change in the cost effectiveness of using certain techniques to achieve "known" price (using storage, fixed price contracts, etc.)				If yes→	AGA: 64%, n=7 APGA: 60%, n=18 cited 2000-2001
AGA	28%	72%	40		

APGA	40%	60%	76		
6. The introduction of a customer choice program in your state				If yes→	AGA: 0%, n=0 APGA: 100%, n=1 cited 2000-2001
AGA	12%	88%	40		
APGA	1%	99%	74		
7. More knowledge about or broader use of the types of gas stabilization tools				If yes→	AGA: 50%, n=8 APGA: 50%, n=9 cited 2000-2001
AGA	39%	61%	41		
APGA	23%	77%	77		
8. Other *(Please specify)*				If yes→	___________
AGA			10		
APGA			15		

Actual Purchases of Natural Gas Supply

6. For each Winter Heating Season (WHS; November 1 – April 1) listed below: **See table 6 and table 7 in appendix III for question 6 results**

(A) about how much natural gas did your utility company **actually** purchase for on-system residential customers during the 1999-2000 and 2000-2001Winter Heating Seasons,
(B) about what percent of natural gas supply did your utility company buy at a price that was **unknown** prior to the beginning of the WHS, and
(C) about what percent did your utility company buy at a price or price range that was **known** prior to the
beginning of the WHS?

Winter Heating Season (Nov 1 to April 1)	(A) **Actual** volume of gas supply purchased for on-system residential customers during WHS (in Mcf)	(B) Prior to the beginning of the WHS, what percent of supply did your utility buy at an **unknown price** ("spot market"). *(Please enter percent; if none, enter '0'.)* Unknown includes: • daily and first of the month spot purchases and • contracts indexed to daily or first of the month prices **(Do not include gas hedged using futures, options, or swaps.)**	(C) Prior to the beginning of the WHS, what percent of supply did your utility buy **at a known price or within a known price range.** *(Please enter percent; if none, enter '0'.)* Known includes: • financial hedging instruments (such as futures, options, swaps, or weather derivatives), • fixed price contracts, and • storage	
1995-1996		%	%	=100%
1996-1997		%	%	=100%
1997-1998		%	%	=100%
1998-1999		%	%	=100%
1999-2000		%	%	=100%
2000-2001		%	%	=100%
2001-2002		%	%	=100%

7. If there are any significant differences between your planned purchases (as appear in Question 4) and actual purchases (as appear in Question 6), please describe the reasons for these differences. (When describing the reasons, please provide the applicable year(s).)

[ ] **Not applicable - no significant change→** ***(Go to Question 8)***

Not applicable – **AGA: 52%, n=38 APGA: 68%, n=87**
Specific response - **AGA: 48%, n=35 APGA: 32%, n=41**

AGA:80%, n=28 APGA: 59%, n=24
of those providing a specific response, cited weather as the reason for differences between planned and actual gas purchases.

8. On average over the past 5 years, about what percent of the natural gas supply purchased for on-system residential customers comes from storage that your LDC owns, contracts for, or controls? (Enter percentage; if none, enter '0'.) **See table 8 in appendix III for question 8 results**

9. During the 2000-01 WHS, did your gas utility use the following gas cost stabilization ("hedging") tools? *(Check one for each tool.)*

	Yes	No	Not applicable -- Regulatory body did not allow use of tool*	Not applicable- Other reason*	N=
1. Storage (including peakshaving)					
AGA	84%	16%	1	1	87
APGA	49%	51%	1	7	156
2. Fixed price contracts					
AGA	56%	44%	1	2	85
APGA	65%	35%	2	4	165
3. Futures (financial instrument)					
AGA	35%	65%	6	4	85
APGA	24%	76%	4	6	149
4. Options					
AGA	36%	64%	3	5	83
APGA	4%	96%	4	7	141
5. Swaps					
AGA	28%	72%	3	5	83
APGA	5%	95%	7	7	144
6. Weather derivatives[1]					
AGA	7%	93%	4	4	82
APGA	4%	96%	6	7	140
7. Other *(Please specify)*					
AGA					13
APGA					30

*Note: These are the number of utility companies that did not have an option to use cost stabilization tools and are not included in the 'N' column.

[1]Weather derivatives are financial products that enable a company to offset its financial risk due to the effect of weather on demand for a product, in this case natural gas.

10. Since 2000-2001, how has your use of the following cost stabilization tools changed, if at all? (Check one for each tool.)

	Currently use			Do not use tool now		
	Use has increased	Use has remained the same	Use has decreased	Plan to use in the next 12 months	Do not plan to use in the next 12 months	N=
1. Storage (including peakshaving)						
AGA	13%	72%	0%	2%	13%	87
APGA	9%	51%	0%	3%	37%	150
2. Fixed price contracts						
AGA	42%	36%	2%	5%	14%	83
APGA	34%	42%	4%	6%	15%	163
3. Futures (financial instrument)						
AGA	23%	29%	2%	8%	38%	79
APGA	22%	19%	1%	5%	52%	139
4. Options						
AGA	20%	30%	5%	9%	36%	77
APGA	5%	13%	2%	5%	75%	134
5. Swaps						
AGA	18%	30%	1%	7%	43%	76
APGA	3%	17%	1%	1%	79%	132
6. Weather derivatives						
AGA	7%	20%	1%	7%	65%	75
APGA	1%	18%	1%	0%	81%	129
7. Other *(Please specify)*						
AGA						6
APGA						33

10a. What were the reasons for the change in your use of cost stabilization tools?

AGA: 67%, n=34 APGA: 67%, n=65
cited high prices or price volatility

11. What type of natural gas utility is your entity? *(Check one.)*

1. [ ] Investor–owned **AGA: 63%, n=57 APGA: 0%, n=0**
2. [ ] Municipally-owned **AGA: 32%, n=29 APGA: 96%, n=168**
3. [ ] Other→ (Please specify) **AGA: 4%, n=4 APGA: 4%, n=8**

12. What is/are the name(s) of the regulatory body(ies) that regulate your utility's gas purchases and rate setting?

AGA: N=88 APGA: N=146

13. What type of regulatory body regulates your utility's gas purchases and rate setting? (Check one.)

1. [ ] One regulator (Check one.) **AGA: 80%, n=72 APGA: 96%, n=163**

   [ ] Local government entity **AGA: 37%, n=26 APGA: 93%, n=150**
   →*(Go to Question 18 on page 8)*

   [ ] State government entity **AGA: 59%, n=42 APGA: 4%, n=7**
   → *(Go to Question 14 on page 7)*

   [ ] Other entity **AGA: 4%, n=3 APGA: 2%, n=4**
   → *(Go to Question 14 on page 7)*

2. [ ] Multiple regulators[2] *(Check all that apply.)* **AGA: 20%, n=18 APGA: 1%, n=2**

   a. [ ] Local government entity →*(Continue)* **AGA: 17%, n=3 APGA: 100%, n=2**

   b. [ ] State government entity →*(Continue)* **AGA: 39%, n=7 APGA: 100%, n=2**

   c, [ ] State government entities in more than one state →*(Continue)* **AGA: 56%, n=10 AGA: 0%, n=0**

3. [ ] Other *(Please specify.)* →*(Continue)* **APGA: n=4**
   AGA: n=0

Instructions for the next series of questions:

If your gas utility's gas purchases and rate setting are regulated by :

- a single local regulatory body, please go to Question 18 on page 8.
- a single state or other regulatory body, please go to Question 14 on page 7.
- multiple regulatory bodies—state government entities in one or more states, or a combination of local and state governments—please complete the series of questions which are repeated for each regulatory body: Questions 14-20 for the first regulatory body, Questions 21-27 for the second, and Questions 28-34 for the third, if applicable.
- more than three regulatory bodies, please copy Questions 14-20 for each additional entity.

[2] As respondents could check more than one answer, the percentage for the three responses under multiple regulator is more than 100 percent.

FIRST (OR ONLY) REGULATORY BODY

Name ___________________________

14. How does this regulatory body regulate your utility's gas purchasing strategy for gas resold to on-system residential customers? *(Check one for each.)*

	Yes	No	N=
1. Regulator <u>requires</u> approval of utility's proposed buying strategy			
AGA	22%	78%	60
APGA	20%	80%	10
2. Regulator <u>does not require</u> approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	24%	76%	58
APGA	30%	70%	10
3. Regulator limits utility's use of financial instruments in buying gas			
AGA	35%	65%	57
APGA	0%	100%	8
4. Regulator audits prudence of gas buying strategy			
AGA	90%	10%	60
APGA	22%	78%	9
5. Other *(Please specify)*			
AGA			10
APGA			2

15. Since 1995, has the regulation of gas purchases as described in Question 14 changed? *(Check one.)*

1. [ ] Yes→ **AGA: 35%, n=21 APGA: 12%, n=3**

a. When did these approaches change?

____

a. Please indicate what the regulatory approaches were before any change. *(Check one for each.)*

	Yes	No	N=
1. Regulator <u>requires</u> approval of utility's proposed buying strategy			
AGA	6%	94%	16
APGA	0%	100%	2
2. Regulator <u>does not require</u> approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	31%	69%	16
APGA	0%	100%	2
3. Regulator limits utility's use of financial instruments in buying gas			

AGA	56%	44%	16
APGA	0%	100%	2
4. Regulator audits prudence of gas buying strategy			
AGA	83%	17%	18
APGA	0%	100%	2
5. Other (Please specify)			
AGA			3
APGA			0

c. What were the reasons for changing the regulatory approaches?

Varied responses

2. [ ] No **AGA: 65%, n=39 APGA: 88%, n=22**

16. Does this regulator set minimum or maximum requirements on how much gas you purchase at an "unknown" price versus a "known" price or price range (as defined in Questions 4 and 6)? *(Check one.)*

1. [ ] Yes → Please explain. **AGA: 8%, n=5 APGA: 0%, n=0**

2. [ ] No **AGA: 92%, n=57 APGA: 100%, n=11**

17. Since 1995, has this regulatory body ever disallowed any costs associated with gas purchases because of a prudence audit or other review? *(Check one.)*

1. [ ]Yes → **AGA: 7%, n=4 APGA: 0%, n=0**

Please summarize the regulatory body's finding(s) in the space below.

Varied responses

2. [ ] No **AGA: 93%, n=57 APGA: 100%, n=11**

18. Which of the following models best describes this regulatory body's general policy governing the setting of gas commodity rates for your utility? *(Check one.)*

1. [ ] Fixed rate model –
Regulator analyzes a utility's past costs in order to set commodity rates
AGA: 3%, n=3 APGA: 38%, n=61

2. [ ] Purchased gas adjustment model –
Customers are charged an approximation of a utility's actual costs, and any differences between actual costs and revenues are reconciled at a later date
AGA: 82%, n=71 APGA: 46%, n=75

3. [ ] Performance based/incentive model –
Commodity rates are adjusted frequently, and the utility benefits from commodity cost savings or pays if commodity expenditures are too great

AGA: 9%, n=8 APGA: 6%, n=9

4. [ ] Other (*Please specify)*
AGA: n=5 APGA: n=17

____

19. How often can your utility adjust its gas commodity rates? (C*heck one.)*

1. [ ] Monthly **AGA: 59% n=52 APGA: 69% n=111**
2. [ ] Quarterly **AGA: 16%, n=14 APGA: 4%, n=6**
3. [ ] Semiannually **AGA: 1%, n=1 APGA: 1%, n=2**
4. [ ] Annually **AGA:9%, n=8 APGA: 10%, n=16**
5. [ ] Other (*Please specify.*) **AGA: 15%, n=13 APGA: 16%, n=26**

20. Does this regulatory body allow your utility to recover all costs associated with the use of financial hedging tools (including futures, options, swaps, and weather derivatives) when purchasing natural gas? (*Check one.)*

1. [ ] Yes **AGA: 86%, n=53 APGA: 92%, n=90**
2. [ ] No **AGA: 14%, n=9 APGA: 8%, n=8**
3. [ ] Not applicable

SECOND REGULATORY BODY

Name ___________________________

21. How does this regulatory body regulate your utility's gas purchasing strategy for gas resold to on-system residential customers? *(Check one for each.)*

	Yes	No	N=
1. Regulator <u>requires</u> approval of utility's proposed buying strategy			
AGA	16%	84%	19
APGA	33%	67%	3
2. Regulator <u>does not require</u> approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	22%	78%	18
APGA	0%	100%	3
3. Regulator limits utility's use of financial instruments in buying gas			
AGA	26%	74%	19
APGA	0%	100%	3
4. Regulator audits prudence of gas buying strategy			
AGA	84%	16%	19

APGA	67%	33%	3
5. Other (*Please specify*)			
AGA			3
APGA			0

22. Since 1995, has the regulation of gas purchases as described in Question 21 changed? *(Check one.)*

1. [ ] Yes→ **AGA: 18%, n=3 APGA: 0%, n=0**

a. When did these approaches change?

Varied responses

b. Please indicate what the regulatory approaches were before any change. (*Check one for each.)*

	Yes	No	N=
1. Regulator requires approval of utility's proposed buying strategy			
AGA	0%	100%	4
APGA			0
2. Regulator does not require approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	75%	25%	4
APGA			0
3. Regulator limits utility's use of financial instruments in buying gas			
AGA	50%	50%	4
APGA			0
4. Regulator audits prudence of gas buying strategy			
AGA	100%	0%	4
APGA			0
5. Other (*Please specify)*			
AGA			1
APGA			0

c. What were the reasons for changing the regulatory approaches?

Varied responses

2. [ ] No **AGA: 82%, n=14 APGA: 100%, n=4**

23. Does this regulator set minimum or maximum requirements on how much gas you purchase at an "unknown" price versus a "known" price or price range (as defined in Questions 4 and 6)? (*Check one.*)

1. [ ] Yes → **AGA: 5%, n=1 APGA: 0%, n=0**
Please explain.

2. [ ] No **AGA: 95%, n=18 APGA: 100%, n=6**

24. Since 1995, has this regulatory body ever disallowed any costs associated with gas purchases because of a prudence audit or other review? *(Check one.)*

    1. [ ]Yes → ***AGA: 5%, n=1 APGA: 0%, n=0***

       Please summarize the regulatory body's finding(s) in the space below.

    2. [ ] No **AGA: 95%, n=18 APGA: 100%, n=6**

25. Which of the following models best describes this regulatory body's general policy governing the setting of gas commodity rates for your utility? *(Check one.)*

    1. [ ] Fixed rate model –
       Regulator analyzes a utility's past costs in order to set commodity rates
       AGA: 0%, n=0 APGA: 33%, n=2

    2. [ ] Purchased gas adjustment model –
       Customers are charged an approximation of a utility's actual costs, and any differences between actual costs and revenues are reconciled at a later date
       AGA: 100%, n=19 APGA: 33%, n=2

    3. [ ] Performance based/incentive model –
       Commodity rates are adjusted frequently, and the utility benefits from commodity cost savings or pays if commodity expenditures are too great
       N=0

    4. [ ] Other (*Please specify.*)
       APGA 2 AGA 0

26. How often can your utility adjust its gas commodity rates? (*Check one.)*

    1. [ ] Monthly **AGA:42%, n=8 APGA: 38%, n=3**
    2. [ ] Quarterly **AGA: 16%, n=3 APGA: 0%, n=0**
    3. [ ] Semiannually **n=0**
    4. [ ] Annually **AGA: 21%, n=4 APGA: 25%, n=2**
    5. [ ] Other (*Please specify.)* **AGA: n=4 APGA: n=3**

       ____

27. Does this regulatory body allow your utility to recover all costs associated with the use of financial hedging tools (including futures, options, swaps, and weather derivatives) when purchasing natural gas? (*Check one.)*

    1. [ ] Yes **AGA: 92%, n=12 APGA: 50%, n=1**

    2. [ ] No **N=2 AGA: 8%, n=1 APGA: 50%, n=1**

    3. [ ] Not applicable

If your utility is governed by only two regulatory bodies, please go to Question 35 on page 13; otherwise, please continue to Question 28.

THIRD REGULATORY BODY

Name ___________________________

28. How does this regulatory body regulate your utility's gas purchasing strategy for gas resold to on-system residential customers? *(Check one for each.)*

	Yes	No	N=
1. Regulator requires approval of utility's proposed buying strategy			
AGA	18%	82%	11
APGA			0
2. Regulator does not require approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	30%	70%	10
APGA			0
3. Regulator limits utility's use of financial instruments in buying gas			
AGA	30%	70%	10
APGA			0
4. Regulator audits prudence of gas buying strategy			
AGA	91%	9%	11
APGA			0
5. Other *(Please specify)*			
AGA			1
APGA			0

29. Since 1995, has the regulation of gas purchases as described in Question 28 changed? *(Check one.)*

1. [ ] Yes→ **AGA: 27%, n=3 APGA: 0%, n=0**

a. When did these approaches change?

Varied responses

b. Please indicate what the regulatory approaches were before any change. *(Check one for each.)*

	Yes	No	N=
1. Regulator requires approval of utility's proposed buying strategy			
AGA	0%	100%	3
APGA			0
2. Regulator does not require approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy			
AGA	33%	67%	3

APGA			0
3. Regulator limits utility's use of financial instruments in buying gas			
AGA	33%	67%	3
APGA			0
4. Regulator audits prudence of gas buying strategy			
AGA	100%	0%	3
APGA			0
5. Other *(Please specify)*			0

c. What were the reasons for changing the regulatory approaches?

Varied responses

2. [ ] No **AGA: 73%, n=8 APGA: 100%, n=1**

30. Does this regulator set minimum or maximum requirements on how much gas you purchase at an "unknown" price versus a "known" price or price range (as defined in Questions 4 and 6)? *(Check one.)*

1. [ ] Yes → **AGA: 9%, n=1 APGA: 0%, n=0**
Please explain.

2. [ ] No **AGA: 91%, n=10 APGA:100%, n=1**

31. Since 1995, has this regulatory body ever disallowed any costs associated with gas purchases because of a prudence audit or other review? *(Check one.)*

1. [ ]Yes → **AGA: 18%, n=2 APGA: 0%, n=0**

Please summarize the regulatory body's finding(s) in the space below.

Varied responses

2. [ ] No **AGA: 82%, n=9 APGA: 100%, n=1**

32. Which of the following models best describes this regulatory body's general policy governing the setting of gas commodity rates for your utility? *(Check one.)*

1. [ ] Fixed rate model -
Regulator analyzes a utility's past costs in order to set commodity rates
AGA: 0%, n=0 APGA: 100%, n=1

2. [ ] Purchased gas adjustment model –
Customers are charged an approximation of a utility's actual costs, and any differences between actual costs and revenues are reconciled at a later date
AGA: 82%, n=9 APGA: 0%, n=0

3. [ ] Performance based/incentive model –
Commodity rates are adjusted frequently, and the utility benefits from commodity cost savings or pays if commodity expenditures are too great

AGA: 18%, n=2 APGA: 0%, n=0

4. [ ] Other (please specify)
n=0

33. How often can your utility adjust its gas commodity rates? (*Check one.)*

1. [ ] Monthly **AGA: 54%, n=6 APGA: 50%, n=1**
2. [ ] Quarterly **AGA:18%, n=2 APGA: 0%, n=0**
3. [ ] Semiannually **n=0**
4. [ ] Annually **n=0**
5. [ ] Other (Please specify.) **AGA 3 APGA 1**

34. Does this regulatory body allow your utility to recover all costs associated with the use of financial hedging tools (including futures, options, swaps, and weather derivatives) when purchasing natural gas? *(Check one.)*

1. [ ] Yes **AGA: 100%, n=7**
2. [ ] No **n=0**
3. [ ] Not applicable

COMMENTS

35. Please provide below any additional comments you have about natural gas prices or about any issues raised by questions contained in this survey.

Varied responses

Please fill out the contact information below.

Name: ______________________________

Title: ______________________________

Department: ______________________________

Telephone number: ______________________________

E-mail address: ______________________________

Mailing address: ______________________________

Appendix III: Additional Results of Investor-Owned and Municipally Owned Utility Survey

The tables in this appendix list results from our survey of 269 gas utilities that could not be displayed in the body of the survey. Table 5 identifies the percentage of the residential customers' gas supply that gas utilities planned to hedge during the winters of 1995-1996 through 2001-2002. It is likely that fewer utilities answered for earlier years because some companies do not keep records for many years. Table 6 identifies the percentage of the residential customers' gas supply that gas utilities actually hedged during the winters of 2000-2001 and 2001-2002. Table 7 identifies the volumes that gas utilities planned to purchase and actually purchased for residential customers in the winters of 1999-2000 through 2001-2002. These volumes cannot be directly compared in some cases because the number of respondents may differ. However, as shown in appendix II, differences between planned and actual gas purchases were in large part due to changes in weather. Finally, table 8 identifies how much of utilities' gas supply came from storage on average over the last 5 years.

Table 5: Gas Utilities' Planned Use of Hedging for Residential Customers

AGA							
Percentage of natural gas supply utilities planned to hedge during the winter heating season	**1995-1996 (N=44)**	**1996-1997 (N=43)**	**1997-1998 (N=45)**	**1998-1999 (N=48)**	**1999-2000 (N=81)**	**2000-2001 (N=84)**	**2001-2002 (N=86)**
0	39	35	27	23	21	20	10
1 to 49	43	49	42	42	38	36	27
50 to 99	14	12	24	29	32	37	52
100	5	5	7	6	9	7	10
APGA							
Percentage of natural gas supply utilities planned to hedge during the winter heating season	**1995-1996 (N=88)**	**1996-1997 (N=89)**	**1997-1998 (N=93)**	**1998-1999 (N=96)**	**1999-2000 (N=159)**	**2000-2001 (N=159)**	**2001-2002 (N=159)**
0	45	42	41	36	31	32	10
1 to 49	7	7	6	9	14	12	9
50 to 99	20	24	24	30	28	31	46
100	27	28	29	24	28	25	35

Source: GAO.

Table 6: Gas Utilities' Actual Use of Hedging for Residential Customers during the Winters of 2000-2001 and 2001-2002

AGA		
Percentage of natural gas supply utilities actually hedged	**2000-2001 (N=85)**	**2001-2002 (N=46)**
0	18	9
1 to 49	44	26
50 to 99	31	57
100	8	9
APGA		
Percentage of natural gas supply utilities actually hedged	**2000-2001 (N=161)**	**2001-2002 (N=86)**
0	30	12
1 to 49	16	12
50 to 99	29	38
100	25	38

Source: GAO.

Table 7: Gas Utilities' Planned and Actual Volumes of Natural Gas Purchased during the Winter Heating Season for Residential Customers

AGA	Median	Range	N=
Planned volumes			
1999-2000	4,373,786	46,647-200,000,000	73
2000-2001	4,229,400	49,127-210,000,000	73
2001-2002	4,940,969	46,800-220,000,000	73
Actual volumes			
1999-2000	3,652,357	46,647-193,000,000	73
2000-2001	4,865,541	49,127-228,000,000	73
APGA	**Median**	**Range**	**N=**
Planned volumes			
1999-2000	97,708	5,100-154,000,000	118
2000-2001	100,000	6,200-145,000,000	122
2001-2002	100,000	6,000-125,000,000	127
Actual volumes			
1999-2000	95,000	5,000-145,000,000	137
2000-2001	95,000	5,820-125,000,000	141

Source: GAO.

Table 8: Use of Natural Gas Storage Among Utilities (on Average over the Past 5 Years)

Percentage of gas supply for residential customers in storage	AGA N=79	APGA N=146
0	15	53
1 to 25	37	27
26 to 50	42	13
51 to 100	6	8

Source: GAO.

Appendix IV: Results of State Regulatory Agency Survey

We surveyed staff specializing in natural gas regulation from the state regulatory agencies, which are usually known as public utility commissions or public service commissions, that oversee gas utilities. We contacted the agencies of the 48 contiguous states and the District of Colombia in a series of structured telephone interviews. However, because the Nebraska Public Service Commission does not regulate gas utility companies (such regulation occurs at the local government level), we exempted this state from our analysis of regulatory agencies. Therefore we received responses from a total of 48 state regulatory agencies.

For each question in the reprinted survey, we identified the number of state regulatory agencies that indicated each response. A few commissions did not respond to all of the questions, so some questions have fewer total respondents than others. In addition, certain questions are presented in greater detail in appendix V.

U.S. General Accounting Office

Questions for Public Utility Commissions (PUCs)

Introduction

Because of the high natural gas prices of the winter of 2000-2001, the Congress has asked the U.S. General Accounting Office to review various issues surrounding the pricing of natural gas. As part of this review, we are conducting a survey of the regulatory utility commissions of the 48 contiguous states and the District of Columbia to collect information on how they regulate and oversee the purchasing of natural gas by utility companies that resell the gas to residential customers. In addition, we are surveying a sample of local distribution companies concerning their gas purchasing strategies.

Your participation in our survey is critical to our providing comprehensive and complete information to the Congress. The results of this data collection effort will be presented in a report that is scheduled to be issued later this year.

Instructions

Per our discussion with you, we are providing this list of questions to help you prepare for our upcoming telephone conference. In the near future, we will contact you again to arrange the date and time for the discussion of the questions. When reviewing these questions, please coordinate with appropriate members of your agency or department. If you have any questions, please call:

Mark Gaffigan
202-512-3168
(e-mail gaffiganm@gao.gov)

James Cooksey
214-777-5687
(e-mail cookseyj@gao.gov)

Thank you for your help!

1. Currently how important, if at all, are the following pricing goals for Local Distribution Companies (LDCs) to consider when purchasing natural gas for on-system residential customers? (*Check one for each pricing goal.*)

	Slightly or not important	Somewhat important	Moderately important	Very important	Extremely important
1. Stable prices	1	4	14	23	6
2. Lowest reasonable price	0	1	12	18	16
3. Prices close to the market	2	12	17	13	3
4. Other (Please specify.) ______	0	0	0	0	8

2. Has your Commission's view on the importance of these goals changed since 1995?

1. [30] Yes →

a. When did it change? **20 of 30 respondents cited the winter of 2000-2001**

b. Prior to this change, how important, if at all, were the following pricing goals for LDCs to consider? (*Check one for each pricing goal.*)

	Slightly or not important	Somewhat important	Moderately important	Very important	Extremely important
1. Stable prices	6	11	8	3	2
2. Lowest reasonable price	0	0	4	14	11
3. Prices close to the market	2	8	13	6	1
4. Other (Please specify.) ____________	0	0	0	0	5

c. What was the reason for changing the importance of the pricing goals? **27 of 30 respondents cited higher gas prices and volatility**

2. [18] No

3. Are there any natural gas residential customer choice programs available in your state? (*Check one.*)

1. [20] Yes

2. [28] No

4. Does your Commission use any of the following approaches to regulate LDCs purchasing gas for resale to on-system residential customers? (*Check one for each.*)

	Yes	No
1. PUC requires approval of utility's proposed buying strategy	10	38
2. PUC does not require approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy	15	33
3. PUC limits utility's use of financial instruments in buying gas	15	33
4. PUC audits prudence of gas buying strategy	42	6
5. Other (*Please specify.*) ____________	12	36

5. Since 1995, have your regulatory approaches identified in question 4 above changed? (*Check one.*)

1. [17] Yes→

a. When did these approaches change?
10 of 17 said winter of 2000-2001

b. Please indicate what the regulatory approaches were before any change. (*Check one for each.*)

	Yes	No
1. PUC requires approval of utility's proposed buying strategy	1	15
2. PUC does not require approval of utility's proposed buying strategy, but utility seeks pre-approval of utility's buying strategy	1	15
3. PUC limits utility's use of financial instruments in buying gas	8	8
4. PUC audits prudence of gas buying strategy	9	7
5. Other (*Please specify.*) ____________	3	

c. What were the reasons for changing the regulatory approaches?
11 of 17 respondents answered high gas prices, price volatility, or an associated increase in utilities' use of hedging tools

2. [31] No

6. Does your Commission set minimum or maximum requirements on how much gas LDCs may purchase at an "unknown" price (such as daily and first of the month spot purchases and contracts indexed to daily or first of the month price) versus at a "known" price or price range (for example, using fixed price contracts, storage, and financial hedging instruments)? (*Check one.*)

   1. [6] Yes → Please explain.

   2. [42] No

7. Which of the following models best describes how your Commission governs the setting of gas commodity rates for LDCs? (*Check one.*) **Please provide any relevant documents explaining your policy.**

   1. [1] Fixed rate model - PUC analyzes a LDC's past costs in order to set commodity rates

   2. [35] Purchased gas adjustment model - Customers are charged an approximation of a LDC's actual costs, and any differences between actual costs and revenues is reconciled at a later date

   3. [1] Performance based/incentive model - Commodity rates are adjusted frequently, and the LDC benefits from commodity cost savings or pays if commodity expenditures are too great

   4. [11] Other (*Please specify*)

   ____

8. How often does your Commission allow LDCs in your state to adjust their gas commodity rates? (*Check one.*)

   1. [22] Monthly

   2. [3] Quarterly

   3. [0] Annually

   4. [23] Other (*Please specify.*)

   ____

9. Please describe the process your Commission uses to ensure that LDCs comply with your gas purchasing policy (prudence reviews, purchased gas audits, etc.). All PUCs reported they use processes such as or similar to prudence reviews or purchased gas audits to ensure compliance with state policies.

10. Since 1995, has your Commission ever disallowed a LDC's gas commodity costs? (*Check one.*)

    1. [14] Yes → Please summarize the reasons for the disallowment. **Various responses**

    2. [34] No

11. For each of the following cost stabilization tools, (A) Does your Commission's policy or position allow LDCs to use this tool? and (B) If it allows the use of the tool, does it encourage, have a neutral position toward, or discourage its use?

Cost Stabilization Tool	(A) Does your Commission allow the use of this cost stabilization tool? (*Check one for each.*)			(B) If yes, does your Commission encourage or discourage the use of this tool? (*Check one for each.*)		
	Allows	Does not allow	Does not apply	Encourages	Neutral	Discourages
1. Storage	45	0	3	28	17	0
2. Fixed price contracts	45	0	3	18	27	0
3. Futures (financial instrument)	42	1	5	12	30	0
4. Options	40	3	5	9	31	0
5. Swaps	36	1	10	6	30	0
6. Weather derivatives[1]	22	4	21	0	21	1
7. Other (*Please specify*) ______________	2	0	0	2	0	0

12. If you allow the use of any of the financial hedging tools listed above (futures, options, swaps, weather derivatives), do you allow the LDCs to recover all costs associated with these tools? (*Check one*)

1. [42] Yes
2. [1] No
3. [5] Not applicable

13. Since 1995, has your Commission's policy or position regarding LDC use of gas cost stabilization tools changed in any way? Please explain.

1.[37]Yes →What was the major reason your Commission changed its policy or position? (*Check one*).

a. [4] Desire to allow gas utilities more flexibility in their gas procurement
b. [23] Price increases during winter of 2000-2001
c. [9] Price volatility since 1995
d. [10] More knowledge about or broader use of the types of gas stabilization tools
e. [2] Other *(Please specify.)*

____

[1] Weather derivatives are financial products that enable a company to offset its financial risk due to the effect of weather on demand for a product, in this case natural gas.

2. [11] No

COMMENTS

14. Please provide any additional comments you have about natural gas prices or about any issues raised by questions in this survey.

Reminder: Please remember to provide any documents relevant to your policy governing the setting of gas commodity rates as requested in question 7.

Thank you for your help.

Appendix V: Additional Results of State Regulatory Agency Survey

This appendix provides selected results from our survey of regulatory agencies located in the 48 contiguous states and the District of Columbia. Table 9 shows what hedging tools the state and the District of Columbia regulatory agencies allow or do not allow gas utilities under their jurisdiction to use when purchasing natural gas for their residential customers. Table 10 shows the various approaches the regulatory agencies use in their oversight of gas utilities.

Table 9: State Regulatory Agency Regulation of Hedging Techniques Used by Utilities for Natural Gas Purchases

State regulatory agency	Storage	Fixed price contracts	Futures	Options	Swaps	Weather derivatives
Alabama Public Service Commission	Allows	Allows	Allows	Allows	Allows	Does not allow
Arizona Corporation Commission	N/A[a]	Allows	N/A	N/A	N/A	N/A
Arkansas Public Service Commission	Allows	Allows	Allows	Allows	Allows	N/A
California Public Utility Commission	Allows	Allows	Allows	Allows	Allows	N/A
Colorado Department of Regulatory Agencies, Public Utility Commission	Allows	Allows	Allows	Allows	Allows	N/A
Connecticut Department of Public Utility Control	Allows	N/A	N/A	N/A	N/A	N/A
Delaware Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows
District of Columbia Public Service Commission	Allows	Allows	Allows	Allows	N/A	N/A
Florida Public Service Commission	N/A	Allows	Allows	Allows	Allows	N/A
Georgia Public Service Commission	Allows	Allows	Allows	Does not allow	Does not allow	Does not allow
Idaho Public Utilities	Allows	Allows	Allows	Allows	Allows	Allows
Illinois Commerce Commission	Allows	Allows	Allows	Allows	Allows	Allows
Indiana Utility Regulatory Commission	Allows	Allows	Allows	Allows	Allows	Allows
Kansas Corporation Commission	Allows	Allows	Allows	Allows	Allows	Allows
Kentucky Public Service Commission	Allows	Allows	Allows	Allows	Allows	N/A
Louisiana Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows
Maine Public Utility Commission	Allows	Allows	Allows	Allows	Allows	Allows
Maryland Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows

State regulatory agency	Storage	Fixed price contracts	Futures	Options	Swaps	Weather derivatives
Massachusetts Department of Public Utilities	Allows	N/A	N/A	N/A	N/A	N/A
Michigan Public Service Commission	Allows	Allows	Allows	Allows	N/A	N/A
Minnesota Public Utility Commission	Allows	Allows	Allows	Allows	N/A	N/A
Mississippi Public Utilities Staff	Allows	Allows	Allows	Allows	Allows	Does not allow
Missouri Public Service Commission	Allows	Allows	Allows	Allows	N/A	N/A
Montana Public Service Commission	Allows	Allows	Does not allow	Does not	N/A	Allows
Nebraska Public Service Commission	No response	No response	No response	No response	No response	No response
Nevada Public Utilities Commission	Allows	Allows	Allows	Allows	Allows	Allows
North Carolina Department of Commerce Utilities Commission	Allows	Allows	Allows	Allows	Allows	Allows
North Dakota Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows
New Hampshire Public Utilities Commission	Allows	Allows	Allows	Allows	Allows	Allows
New Jersey Board of Public Utilities	Allows	Allows	Allows	Does not allow	Allows	Allows
New Mexico Public Regulatory Commission	Allows	Allows	Allows	Allows	Allows	Allows
New York Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows
Ohio Public Utility Commission	Allows	Allows	Allows	Allows	Allows	Allows
Oklahoma Corporation Commission, Public Utility Division	Allows	Allows	N/A	N/A	N/A	N/A
Oregon Public Utility Commission	Allows	Allows	Allows	Allows	Allows	N/A
Pennsylvania Public Utility Commission	Allows	Allows	Allows	Allows	Allows	N/A
Rhode Island Public Utility Commission	Allows	Allows	Allows	Allows	Allows	Does not allow
South Carolina Public Service Commission	Allows	Allows	Allow	Allows	No response	No response
South Dakota Public Utilities Commission	Allows	Allows	Allows	Allows	Allows	Allows
Tennessee Regulatory Authority, Energy and Water Division	Allows	Allows	Allows	Allows	Allows	N/A

State regulatory agency	Storage	Fixed price contracts	Futures	Options	Swaps	Weather derivatives
Texas Railroad Commission	N/A	N/A	N/A	N/A	N/A	N/A
Utah Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows
Vermont Public Service Board	Allows	Allows	Allows	Allows	Allows	Allows
Virginia State Corporation Commission	Allows	Allows	Allows	Allows	Allows	N/A
Washington Utilities and Transportation Commission	Allows	Allows	Allows	Allows	Allows	N/A
West Virginia Public Service Commission	Allows	Allows	Allows	Allows	Allows	N/A
Wisconsin Public Service Commission	Allows	Allows	Allows	Allows	Allows	N/A
Wyoming Public Service Commission	Allows	Allows	Allows	Allows	Allows	Allows

[a]Either the regulatory agency has not addressed this technique in its policy or procedures or the technique is not available.

Source: GAO.

Table 10: State Regulatory Agency Oversight of Gas Utilities

Regulatory agency	Regulatory approval of buying strategy required	Utilities seek approval of buying strategy but not required	Regulator limits Use of financial derivatives	Regulator conducts prudence audits	Since 1995 regulator has disallowed utility gas commodity costs
Alabama Public Service Commission	No	No	No	No	No
Arizona Corporation Commission	No	No	No	Yes	No
Arkansas Public Service Commission	No	Yes	No	Yes	No
California Public Utility Commission	No	No	Yes	Yes	Yes
Colorado Department of Regulatory Agencies, Public Utility Commission	No	No	No	Yes	No
Connecticut Department of Public Utility Control	No	No	No	Yes	Yes

Regulatory agency	Regulatory approval of buying strategy required	Utilities seek approval of buying strategy but not required	Regulator limits Use of financial derivatives	Regulator conducts prudence audits	Since 1995 regulator has disallowed utility gas commodity costs
Delaware Public Service Commission	No	No	Yes	Yes	No
District of Columbia Public Service Commission	No	No	Yes	Yes	No
Florida Public Service Commission	Yes	No	No	Yes	No
Georgia Public Service Commission	Yes	No	Yes	Yes	No
Idaho Public Utilities Commission	No	Yes	No	Yes	No
Illinois Commerce Commission	No	No	No	Yes	Yes
Indiana Utility Regulatory Commission	No	Yes	No	Yes	Yes
Iowa Utilities Board	No	No	Yes	Yes	No
Kansas Corporation Commission	No	No	No	No	No
Kentucky Public Service Commission	No	No	Yes	No	No
Louisiana Public Service Commission	No	Yes	No	Yes	No
Maine Public Utility Commission	No	No	No	No	No
Maryland Public Service Commission	No	No	Yes	Yes	No
Massachusetts Dept. of Public Utilities	Yes	No	No	Yes	No
Michigan Public Service Commission	Yes	No	Yes	Yes	Yes
Minnesota Public Utility Commission	No	No	Yes	Yes	No
Mississippi Public Utilities Staff	No	Yes	Yes	Yes	No

Regulatory agency	Regulatory approval of buying strategy required	Utilities seek approval of buying strategy but not required	Regulator limits Use of financial derivatives	Regulator conducts prudence audits	Since 1995 regulator has disallowed utility gas commodity costs
Missouri Public Service Commission	No	No	No	Yes	Yes
Montana Public Service Commission	No	No	No	Yes	No
Nebraska Public Service Commission	No response	No response	No response	No response	No response
Nevada Public Utilities Commission	No	Yes	No	Yes	No
North Carolina Department of Commerce, Utilities Commission	No	Yes	No	Yes	Yes
North Dakota Public Service Commission	No	Yes	No	Yes	No
New Hampshire Public Utilities Commission	Yes	No	No	Yes	Yes
New Jersey Board of Public Utilities	Yes	No	No	Yes	No
New Mexico Public Regulatory Commission	No	No	No	Yes	No
New York Public Service Commission	No	Yes	No	Yes	No
Ohio Public Utility Commission	No	No	No	Yes	No
Oklahoma Corporation Commission, Public Utility Division	No	No	No	Yes	Yes
Oregon Public Utility Commission	No	Yes	Yes	Yes	No
Pennsylvania Public Utility Commission	Yes	No	Yes	Yes	Yes
Rhode Island Public Utility Commission	No	Yes	No	Yes	Yes
South Carolina Public Service	Yes	No	Yes	Yes	No

Regulatory agency	Regulatory approval of buying strategy required	Utilities seek approval of buying strategy but not required	Regulator limits Use of financial derivatives	Regulator conducts prudence audits	Since 1995 regulator has disallowed utility gas commodity costs
Commission					
South Dakota Public Utilities Commission	No	No	No	No	No
Tennessee Regulatory Authority, Energy and Water Division	No	No	Yes	Yes	Yes
Texas Railroad Commission	No	No	No	Yes	Yes
Utah Public Service Commission	No	Yes	No	Yes	No
Vermont Public Service Board	No	Yes	No	Yes	Yes
Virginia State Corporation Commission	Yes	No	No	No	No
Washington Utilities and Transportation Commission	No	Yes	No	Yes	No
West Virginia Public Service Commission	No	No	No	Yes	No
Wisconsin Public Service Commission	Yes	No	Yes	Yes	No
Wyoming Public Service Commission	No	Yes	No	Yes	No

Source: GAO.

Appendix VI: Comments from the Federal Energy Regulatory Commission

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

November 15, 2002

OFFICE OF THE CHAIRMAN

Mr. Jim Wells
Director, Natural Resources and Environment
United States General Accounting Office
441 G St., NW, Room 2T23
Washington, DC 20548

Re: GAO Draft Report Entitled Natural Gas Analysis of Changes in Market Price

Dear Mr. Wells:

Thank you for your November 7, 2002 letter enclosing your draft report of Natural Gas: Analysis of Changes in Market Price. I appreciate the opportunity to comment on this report and congratulate you on your effort.

In general, I agree with the conclusions of your report. As the report indicates, FERC previously lacked an adequate regulatory and oversight approach to monitor a restructured natural gas industry.

With the creation of OMOI, FERC has taken the steps needed to oversee and assess the fair and efficient operations of electric power and natural gas markets. OMOI's job will be to understand energy markets and risk management, measure market performance, and analyze market data with an eye to recommending market improvements, investigate compliance violations, and where necessary, pursue enforcement actions. In fact, a major undertaking this year by OMOI will be the assessment of the data we already collect with the goal of fine-tuning the data we need to monitor electric power and natural gas markets effectively.

I have a few specific comments to clarify several points in this report, especially relating to our jurisdictional authority.

The draft report may lead the reader to misunderstand the scope of FERC's authority to oversee wholesale natural gas markets. On page 35, the draft accurately states that FERC is responsible for the regulation of terms, conditions, and rates for the

- 2 -

transportation of natural gas, but has limited jurisdiction over sales for resale, and no jurisdiction over producer prices of natural gas. However, on pages 4 and 14, the reader is given the impression that FERC has much broader authority and responsibility. We suggest that the summary statements of FERC's responsibility and authority on pages 4 and 14 be revised to reflect the limited nature of our authority as described on page 35.

In my November 12, 2002 testimony to the Senate Committee on Governmental Affairs, I stated, "[t]he Commission also has jurisdiction over transportation and sales for resale of natural gas. However, FERC's jurisdiction over sales for resale is limited to domestic gas sold by pipelines, local distribution companies, and their affiliates (including energy marketers). Consistent with Congressional intent, the Commission does not prescribe prices for these commodity sales."

Therefore, we suggest revising the text on page 4 to state:

> The Federal Energy Regulatory Commission (FERC) has responsibility for ensuring "just and reasonable rates" for the interstate transportation of natural gas, certain sales for resale of natural gas, and the wholesale price of electricity sold in interstate commerce.

On page 14 we suggest the following:

> FERC was established in 1977 as a successor to the Federal Power Commission and is the principal agency responsible for overseeing the interstate natural gas grid which underpins the natural gas market.

The draft report provides an out-of-date picture of FERC's efforts to refocus and retool its oversight of competitive energy markets. On page 35, the draft report discusses the formation of the Office of Market Oversight and Investigation to oversee and assess the operation of energy market. However, the discussion on page 32 fails to give the agency credit for this effort.

We suggest revising the page 32 discussion to read:

> As we have recently reported, FERC has not adequately revised its regulatory and oversight approach to respond to the transition to competitive energy markets. We note, however, that FERC has recently taken actions to correct this with the formation of the Office of Market Oversight and Investigation (OMOI).

- 3 -

Thank you for your insights into the causes of volatility in natural gas markets. I appreciate the hard work your staff put into this report and hope it will enable us to focus our market oversight and data collection. Again, I appreciate the opportunity to comment on your report.

Best regards,

Pat Wood, III
Chairman

Appendix VII: Comments from the Energy Information Administration

Department of Energy
Washington, DC 20585

Mr. Jim Wells
Director, Natural Resources and
Environment
U.S. General Accounting Office
441 G Street, NW
Washington, D.C. 20548

NOV 18 2002

Dear Mr. Wells:

The Energy Information Administration (EIA) has reviewed your draft report, **Analysis of Changes in Natural Gas Prices** (GAO-03-46) and generally agrees with your findings and conclusions. EIA does recognize the need to collect more accurate and timely data on the natural gas market and has begun taking steps to update its data collection program for natural gas. EIA appreciates your support for these efforts and understands that it is important that the agency continue to refine its efforts to provide more timely natural gas market data and focus on implementing changes to its natural gas data collection program as soon as possible, as you recommend.

As you noted, EIA recently began its first weekly data release for natural gas – the Weekly Natural Gas Storage Report. While this significantly improves the timeliness of the overall natural gas data program, EIA would like to call your attention to a number of efforts recently completed or scheduled for completion by summer 2003 to further improve natural gas data quality and timeliness. These include:

- Change in natural gas data sources and concepts – EIA has changed the definition of the industrial and electric power end-use sectors in natural gas reports to use data collected from electric power generators rather than gas delivery agents to represent consumption by electricity generators. This has improved the completeness and accuracy of natural gas consumption series in annual reports and will be implemented in monthly reports in 2003.
- Redesign of survey forms – EIA received OMB approval in November 2002 for implementation in 2003 of revised survey forms with updated industry terms.
- Redesign of survey processing system – EIA is converting the largest monthly and annual survey forms during 2003 to a new processing system that will support improved data quality and nonresponse tracking.
- Improvement in price series coverage – Starting with January 2003 data, EIA will incorporate price data from a recently implemented survey of gas marketers to improve the quality of residential and commercial prices in 5 large States.

In addition, EIA is studying further changes to its natural gas data collection program to determine their feasibility and potential resource requirements. These include:

- Development of a new approach to natural gas production data collection – EIA is exploring alternatives to the present voluntary survey of States, including collecting components of natural gas production directly from producers.
- Development of a new approach to industrial price estimation – EIA explored a Bureau of the Census-related survey collection approach for this series but after learning the cost ($0.75 --$1.00 million) is now exploring estimation alternatives using EIA electricity generator data.
- Development of a new monthly survey of liquefied natural gas (LNG) inventories, injections, and withdrawals -- EIA does not collect monthly data about U.S. LNG operations. Because LNG's role in short-term natural gas supply is increasing, EIA is studying options for new information about LNG supplies.
- More frequent reviews of natural gas industry changes – EIA plans to investigate and react to changes in industry participants and operations more frequently in the future to assure accurate, complete reporting of industry activities.

EIA expects to complete its assessments of the merit and resource requirements for the projects described above in 2003. Undoubtedly the changes will require additional resources for development and for ongoing program operations. Whatever the outcome of our analysis of these specific new projects, because natural gas represents a quarter of the U.S. energy supply and is essential to U.S. consumers and businesses, EIA is committed to updating and improving the natural gas collection program to the extent of our ability and resources.

Thank you for the opportunity to comment on this report.

Sincerely,

Guy F. Caruso
Administrator

Appendix VIII: GAO Contacts and Staff Acknowledgments

GAO Contacts

Jim Wells (202) 512-3841

Mark Gaffigan (202) 512-3168

Acknowledgments

In addition to those named above, James Cooksey, James Rose, Daren Sweeney, Timothy Minelli, Diane Berry, Philip Farah, Luann Moy, Mark Ramage, Barbara Timmerman, and Nancy Crothers made key contributions to this report.

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