
Long-Term Strategies Are Key In Achieving Stable Natural Gas Prices

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LONG-TERM STRATEGIES ARE KEY IN ACHIEVING STABLE NATURAL GAS PRICES

The near-doubling of natural gas prices following the hurricane damage to production and transportation infrastructure in 2005 got the attention of regulators, gas and electric utilities, and their customers. The short-term price effects of the hurricanes have largely dissipated, but the underlying factors that lead to extreme price spikes and price volatility remain. Traditional supply sources of natural gas are declining in productivity, and production costs are increasing. While the United States has relied primarily on North American gas, liquefied natural gas (“LNG”) imports now make up about three percent of U.S. consumption, and the amount is projected to increase significantly to make up for shortfalls in North American supply. This growing reliance on LNG imports makes U.S. markets more susceptible to price fluctuations on the world market for natural gas and more dependent on foreign fuels. Rising imports and the new patterns of production both require new investment in infrastructure. Finally, the increasing number of financial entities trading in natural gas markets has added to the price volatility.

Taken together, these factors lead to the conclusion that natural gas prices will remain relatively high, and highly volatile, over the long-term. This high-price, high-volatility forecast makes natural gas a particularly bad choice as the marginal fuel in electricity generation because in many wholesale electric markets, the marginal fuel now sets the price. Regulators and legislators, therefore, need a long-term strategy to ensure a more stable price environment for both natural gas and electricity. Strategic goals should include increasing domestic production of natural gas, reducing demand for natural gas and electricity, implementing better oversight of financial energy markets, and encouraging long-term investment in infrastructure.

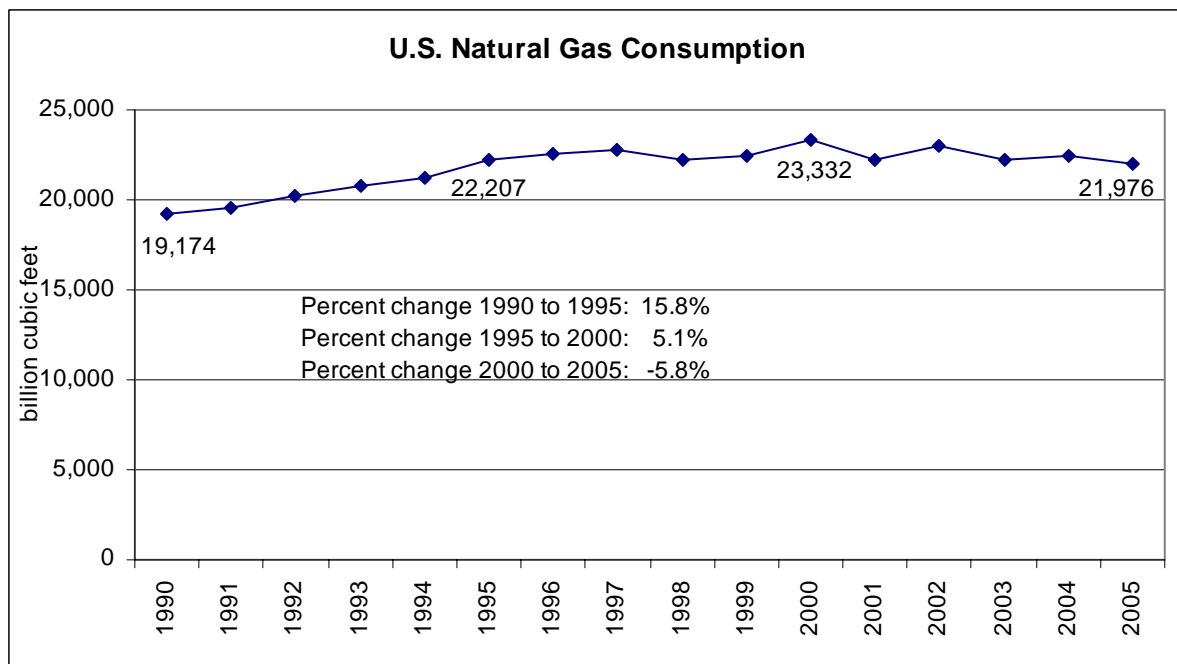
Natural Gas Prices in the Short Term

North American production of natural gas is generally tight relative to demand, so natural gas prices react strongly to events – such as cold weather or low storage levels – that can affect the short-term supply/demand balance. Spikes in demand or supply disruptions can potentially result in shortages, so market participants, including speculators, bid up prices in response to the increased risk of shortages.

Weather is the single most important factor driving the demand for natural gas in the U.S. Very cold winters result in greater consumption by residential customers, and hot summers result in greater consumption by electric generators. This sensitivity to weather has increased because industrial consumption, which is generally not weather-sensitive, has fallen in reaction to high prices. Average prices for industrial customers in the late-

1990s were in the \$3 to \$4 per thousand cubic feet (“MCF”) range, and rose to \$6.56 per MCF in 2004 and \$8.47 per MCF in 2005.¹ These large price increases have resulted in demand destruction, as some industrial customers cut back on production, closed plants or relocated to foreign countries that have excess supplies of gas at cheap prices. For example, beginning in 2003 Dow Chemical has closed 23 U.S. plants and shifted production to Kuwait, Argentina, Malaysia and Germany.²

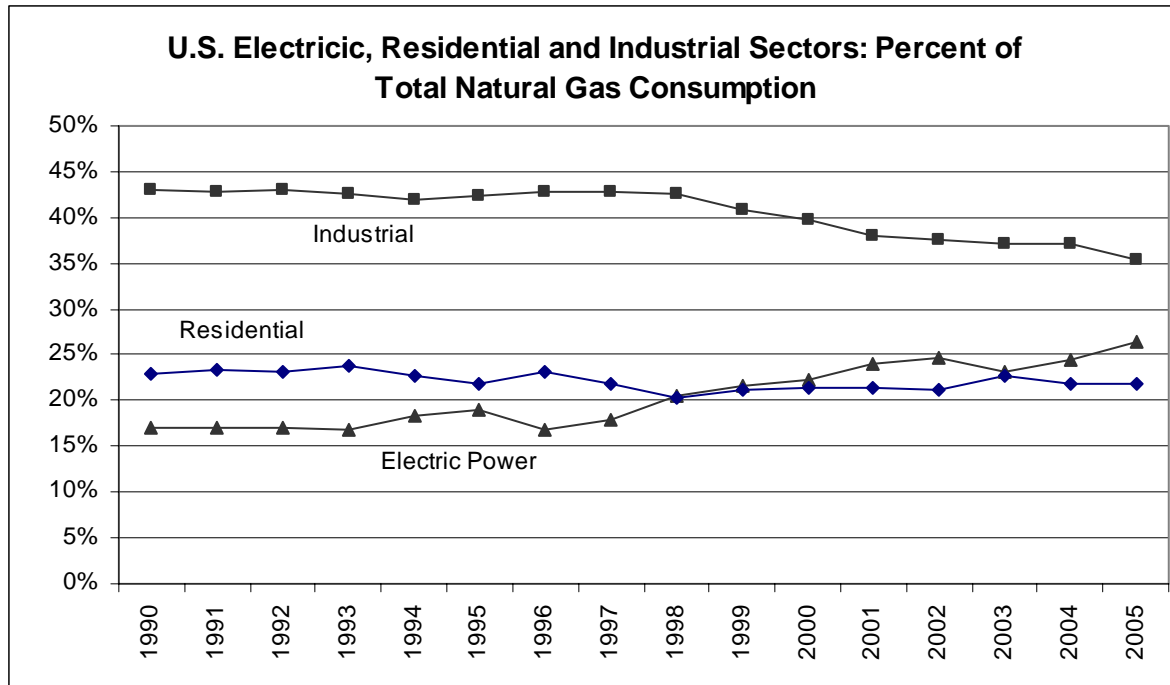
The following graphs show that total U.S. natural gas consumption has remained fairly flat since the mid-1990s. However, consumption by the electric power sector has increased – from less than 20 percent of the total to over 25 percent – and consumption by the industrial sector has fallen – from over 40 percent of the total to 35 percent.



Source: Energy Information Administration, *Monthly Energy Review* and *Natural Gas Monthly*.

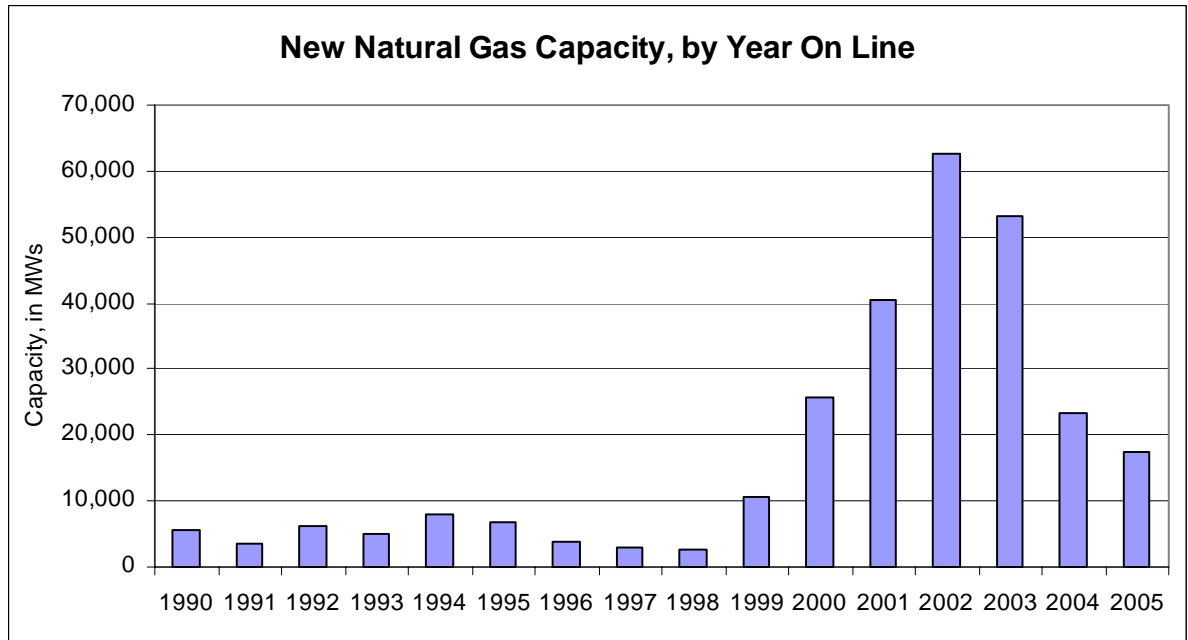
¹ Energy Information Administration, *Natural Gas Monthly*, and *Monthly Energy Review*.

² Simon Romero, “Natural Gas Poses Threat to Economy,” *The New York Times*, November 15, 2005, quoting Senate testimony of Andrew N. Liveris, CEO of Dow Chemical Company.



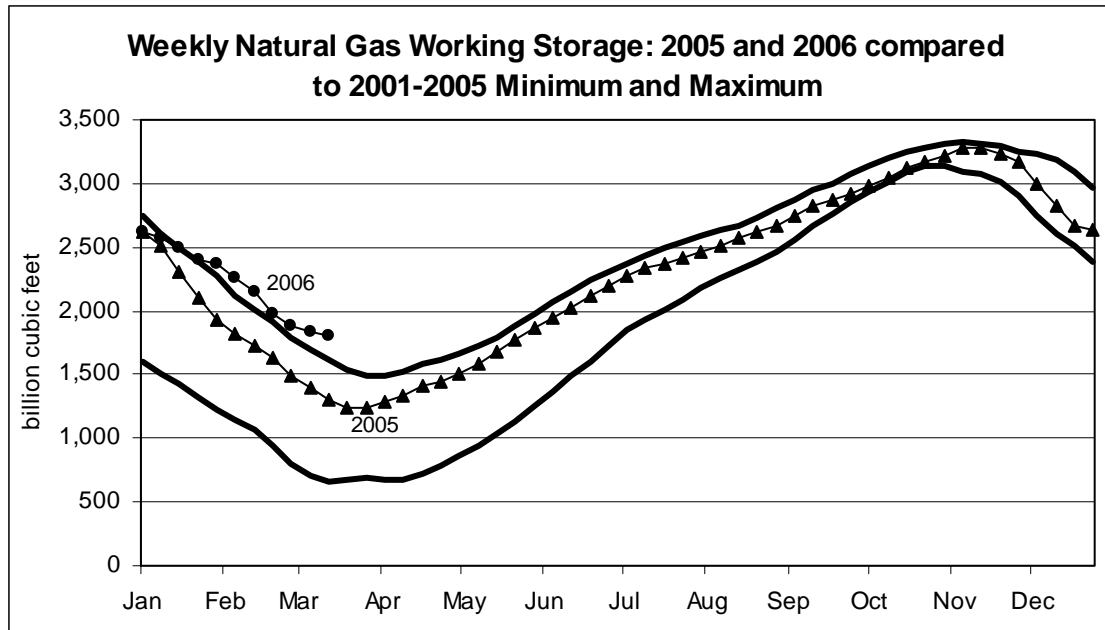
Source: Energy Information Administration, *Monthly Energy Review* and *Natural Gas Monthly*.

The Energy Policy Act of 1992 and the Federal Energy Regulatory Commission’s (“FERC”) Order No. 888 opened the door to widespread participation by merchant generators in electric power markets, and the result was a boom in construction of natural gas generating facilities. As the following chart shows, beginning in 2000 there was a dramatic increase in the amount of new gas-fired capacity, with a total of 223 gigawatts beginning commercial service between 2000 and 2005. These plants not only increase the demand for natural gas, but also result in more opportunities for natural gas generators to set the market clearing price in markets operated by regional transmission organizations (“RTOs”) or independent system operators (“ISOs”).



Source: Energy Velocity data base.

Natural gas in storage facilities is used to help production keep up with demand during the high-demand months. Storage levels are typically drawn down over the winter in response to demand, and then built up again prior to the next winter's heating season. While the Strategic Petroleum Reserve stores a significant amount of oil that can be released in times of tight supply or very high oil prices, there is not a similar degree of protection for natural gas. The current storage capacity for natural gas offers only a small cushion against colder than normal weather or supply disruptions, and so the storage reports are closely watched as an indicator of whether or not supplies will be adequate. Low storage levels going into the winter season increase the potential for shortages, and prices are bid up in response to the greater perceived risk. The following graph shows how storage levels vary over the course of a year. The higher-than-normal storage levels in early 2006 result from the very mild winter weather.



Source: Energy Information Administration, *Weekly Natural Gas Storage Report*. The two solid lines represent the minimum and maximum values for the 2001-2005 time period, as reported by EIA in its “Historical Data” spreadsheet, available at: <http://tonto.eia.doe.gov/oog/info/ngs/history.html>.

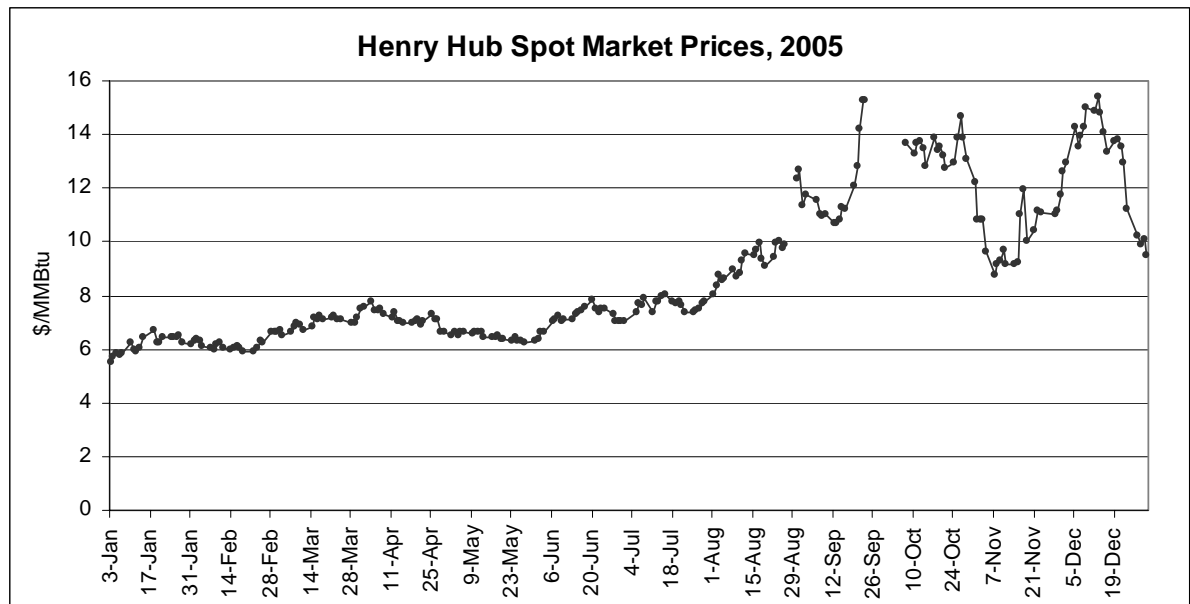
The effects of cold weather, low natural gas storage levels, infrastructure damage or other events having the potential to influence supply or demand are easily magnified by the herd mentality, as traders are typically reacting to the same information. As the price is bid up, utilities and other consumers may enter the market and try to lock in the new, higher price – guarding against potentially greater increases – and thereby put more upward pressure on the price. This herd-mentality dynamic explains the market’s reaction in November 2004 when the Energy Information Administration (“EIA”) published a weekly gas storage report showing larger than expected withdrawals. The price of the next month’s futures contract was bid up more than 17 percent during the ninety minutes remaining in trading that day.³ This strong reaction to one piece of data – which, because of a clerical error, was almost three times the actual amount – highlights the lack of available information on natural gas markets.⁴

Following the crowd is also an explanation for the extreme reaction to the loss of natural gas production in the Gulf of Mexico after Hurricane Katrina and Hurricane Rita. As shown in the graph below, spot prices more than doubled in a very short period, before falling in response to milder weather and the increasing amounts of natural gas in

³ “EIA Defends Storage Reporting Process, Industrials Call for Daily Posting,” NGI’s Daily Gas Price Index, December 2, 2004

⁴ See Greg Burns, “Why Your Natural Gas Bills Have Soared this Winter; Traders Take Prices on Roller-Coaster Ride,” *Chicago Tribune*, January 15, 2006, for comments of Tom Kloza, chief oil analyst at the Oil Price Information Service, on the lack of information on natural gas: “In the oil business, you have a lot of good statistics you can sink your teeth into . . . In natural gas, you have a lot less. It moves much more on the basis of crowd behavior.”

storage. The spike in prices in December coincides with several days of cold weather, before milder weather returned.



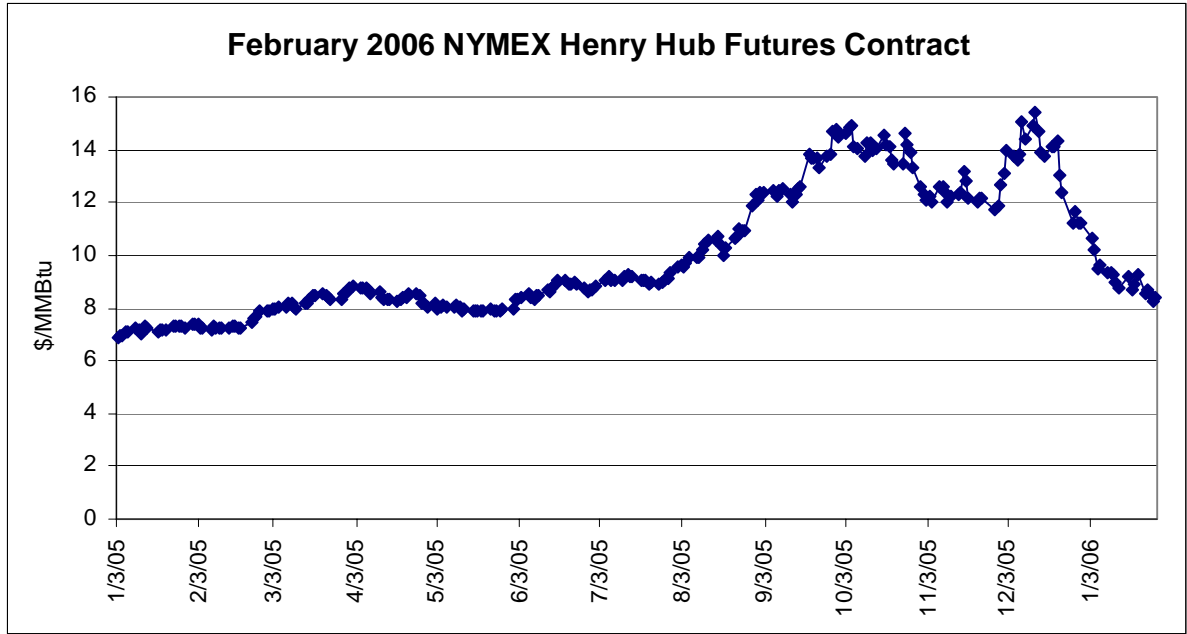
Source: Energy Information Administration, *Natural Gas Weekly Update*.

Spot prices for natural gas at the Henry Hub continued to fall – from around \$9 per million Btu (“MMBtu”) in January 2006 to around \$7 per MMBtu by mid-March – as high storage levels eased fears of supply shortages. Continuing high storage levels should keep prices moderate in the short term.

Financial Players in Energy Markets

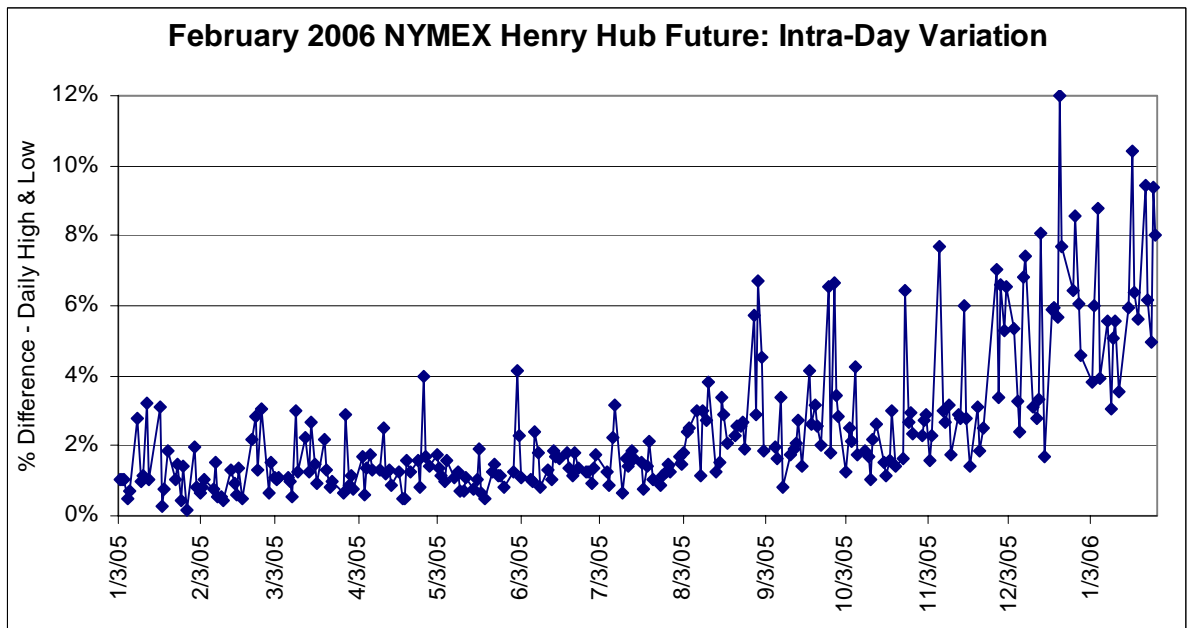
Highly volatile markets – markets that have large price swings in a short period of time – attract speculators. Energy markets typically exhibit high volatility because they respond to complex and unpredictable factors and unlike financial products, ultimately must be delivered to meet demand. For natural gas markets, factors influencing price include production, processing, transportation, storage, gas quality, weather and environmental standards. The current tight supply and demand conditions for natural gas increase the effect of changes in these factors.

The following graph depicts the wide variations in the price of the February 2006 Henry Hub natural gas futures contract on the New York Mercantile Exchange (“NYMEX”) over a one-year period. There were substantial price changes even without considering the disruptions caused by the hurricanes, as prices for the February 2006 contract rose from almost \$7 per MMBtu in January 2005 to over \$10 per MMBtu by early August, and day-to-day price swings of greater than one percent were common. Prices rose to over \$14 per MMBtu after Hurricane Katrina.



Source: NYMEX daily closing prices for Henry Hub natural gas futures, as compiled by Energy Velocity.

The intra-day volatility was even greater, as shown in the graph below. The daily high value and daily low value differed by over five percent on 70 percent of the trading days during the last two months of the contract.



Source: NYMEX daily closing prices for Henry Hub natural gas futures, as compiled by Energy Velocity.

The high volatility makes it no surprise that natural gas and other energy markets have attracted large numbers of financial players. Huge profits can be made:

But the eye-popping profits earned by the market leaders, Goldman Sachs and Morgan Stanley, have spurred other banks to get into the game. In 2004, Goldman and Morgan Stanley earned about \$2.6 billion combined from commodities trading, most of that from energy, according to Sanford C. Bernstein & Company in New York.⁵

In addition, changes in regulations have made it possible for a broader group of financial companies to participate in energy markets. First, the Financial Services Modernization Act became law in 1999.⁶ This act repealed the prohibition against financial holding companies, thereby allowing the creation of holding companies that could own commercial banks, investment banks and insurance companies as affiliated subsidiaries. However, there was little change in regulatory oversight. Separate entities continue to regulate each of the three different functions, and no single regulator has oversight across all three functions. Next, in July 2003 the Federal Reserve approved a regulation allowing commercial banks to trade derivatives (*e.g.* futures or options contracts) based on energy and other non-financial commodities. Previously commercial banks were prohibited from dealing in contracts for commodities, such as energy, that required the trader to take possession of the commodity.⁷

Among the new entrants into energy markets are hedge funds, which are exempt from many of the regulations that govern other mutual funds.⁸ Typically hedge funds have aggressive investing goals and use high-risk techniques. *The Wall Street Journal* described the effect of this “surge in investor speculation” in energy markets:

Hedge funds are taking ever-larger bets in a futures market that is smaller than the stock or bond markets, and the funds are using borrowed money to maximize their bets, magnifying the impact on prices. They are also trading heavily in short-term futures that call for delivery in just a few months rather than a year or more, a practice that also can push prices around.⁹

The *Energy Hedge* newsletter has identified 424 hedge funds active in energy markets, and estimates that 43 percent of these specialize in energy, while the others have a significant energy component in their portfolio.¹⁰ The newsletter’s authors described how the entrance of hedge funds has structurally changed energy markets:

⁵ Alexei Barrionuevo, “Energy Trading, Without a Certain ‘E’,” *The New York Times*, January 15, 2006.

⁶ For a history of financial regulation in the United States, go to www.riskglossary.com, and click on “commercial banks.”

⁷ Federal Reserve System, Final Rule in Regulation Y; Docket No. R-1146, “Bank Holding Companies and Change in Bank Control,” June 27, 2003.

⁸ In December 2004, the Securities and Exchange Commission issued rules tightening the requirements for registration of hedge fund advisors under the Investment Advisers Act of 1940. This followed a staff report on the growth of hedge funds.

⁹ Ann Davis, “The Energy Trading High Wire – Big Profits Lure Rich Investors, But Wild Rides Rattle Them; Making Wagers in ‘Gas Vegas’,” *The Wall Street Journal*, March 21, 2006.

¹⁰ Gary M. Vasey, “A Closer Look at the Energy Hedge Fund Universe,” *Energy Hedge*, Volume 1, Number 12, November 15, 2005.

All this new “risk capital” will probably increase price volatility in the oil, gas and coal markets and many traditional hydrocarbon futures traders are grumbling about this new volatility. They will have to adapt to the new energy market reality, characterized by more price volatility in intra-day energy trading, which will require a different kind of trading acumen. We expect that electricity and gas utilities, increasingly, will become marginalized in this new era of deep-pockets energy traders and that they will mostly abandon energy trading in the U.S. as Wall Street analysts consider such activities a negative on their equity prices. Dynamics in the new energy market will be influenced by multinational oil companies, investment banks and energy hedge funds. This new trading dynamic will require acumen, credit worthiness and risk taking at an unprecedented level.¹¹

Concerns About Oversight of Energy Markets

The consumer sector – including industrial customers and municipal gas distribution companies – has called for better oversight of natural gas markets. In the spot markets, concerns include the low levels of trading (lack of liquidity) in certain markets and the reliance on price indices that are developed with little oversight. The index publishers have greatly improved their procedures as the result of FERC’s investigations into price reporting and the potential for manipulation of natural gas indices. In November 2004 FERC approved a list of index publishers whose practices meet FERC’s reliability standards, and their indices can be used in Commission-approved tariffs. However, FERC stopped short of requiring index publishers to collect counterparty information from traders – a step that is crucial in verifying data and ensuring the quality of indices.

In futures markets, a major concern is the lack of information about market transactions. Consumers want to know the answers to questions such as:

- Who are the market participants?
- Do they have any affiliated companies in the market?
- What is the size of their positions in the market?
- How do their positions compare with any positions taken by an affiliate?
- Can their positions in one market affect the movement of prices in another market in which they hold contracts?

As the regulator of NYMEX, the Commodity Futures Trading Commission (“CFTC”) has access to data on energy futures and options traded on the exchange. However, if hedge funds or others make trades via banks, their identity is not known by the CFTC. In addition, the bulk of trades – particularly longer-term trades – are thought to take place in over the counter (“OTC”) markets, and the CFTC does not have regulatory authority

¹¹ Peter Fusaro and Gary Vasey, “Energy Hedge Funds Enter Centre Stage,” *Pipeline*, February 2005.

over OTC markets.¹² Affiliates can be active in the same set of markets, with one affiliate taking a position on NYMEX and the other holding OTC contracts. Thus the CFTC cannot assess any trader's overall level of investment in natural gas markets or how positions taken in one market may affect the trader's profits in another market.

There is a history of market manipulation in energy markets. Given the large size of the markets, the potential for significant price swings, and the financial incentives of traders, it is only realistic to expect that traders will continue to use all of the tools available to create volatility and profits. For example, a London *Daily Telegraph* news account described traders' concerns over the ability of the Brent oil market to function properly:

Industry sources said there was only a very fine line between creating an illegal monopoly and using experience to create a clever trading position to legitimately enhance profits.¹³

Other examples of manipulation in energy markets include:

- The CFTC entered into a settlement with Avista Corporation and Avista traders over manipulation of electricity futures on NYMEX. The traders attempted to influence the closing price of electricity in order to make a profit on OTC option contracts.¹⁴
- The CFTC imposed fines on a Royal Dutch Shell trader and a company subsidiary for a series of false trades in the oil futures market. Traders for two separate Shell subsidiaries engaged in mirror-image trades, which swapped a prearranged amount of oil futures contracts for delivery in the same month.¹⁵

Energy markets are too important to the national economy and consumer welfare to allow market distortions and excess price volatility caused by price manipulation. Regulators must develop better information on how energy markets work – including identification of the major participants – and use this to better define the “fine line” between illegal market manipulation and legitimate profits. This will allow regulators to more easily identify bad behavior and decrease the incentive for traders to skirt the letter of the law.

¹² The 1974 Commodity Exchange Act created the CFTC and established its exclusive jurisdiction over commodity futures and options. However, the 1974 law was unclear as to whether the CFTC had jurisdiction over OTC markets. The Commodity Futures Modernization Act of 2000 specifically exempted OTC markets from CFTC regulation. (See www.riskglossary.com for a history of the CFTC.)

¹³ David Litterick, “Oil Firm In Court Over Price Claims,” *The Daily Telegraph*, September 14, 2000. The article describes a major U.S. oil refiner's suit against a British oil trading company. The suit alleged that the company manipulated the market for Brent crude oil in August and September 2000 by knowingly purchasing more contracts than could be delivered, thereby obtaining a monopoly position and causing Brent prices to rise by up to \$3 per barrel. The suit also alleged that because many oil markets are priced against Brent oil, prices rose throughout the Atlantic basin.

¹⁴ Randall Dodd and Jason Hoody, “Learning Our Lessons: A Short History of Market Manipulation and the Public Interest,” Derivatives Study Center, April 9, 2002.

¹⁵ Chip Cummins, “Shell Trader, Unit are Fined Over Bogus Oil Trades,” *The Wall Street Journal*, January 5, 2006.

In markets such as natural gas and oil that respond sharply to perceived changes in supply and demand, new “information” can have a significant effect on prices. Last March, equity analysts at Goldman Sachs, noting that oil prices were entering a “super-spike” period, raised their forecast from a high of \$80 per barrel to a high of \$105 per barrel. The same day, crude oil futures for May 2005, the next delivery month, rose by 2.6 percent. *The Wall Street Journal* called the report “market-moving” and also described Goldman Sachs’ strong position in energy markets:

In the energy boom of recent years, Goldman Sachs Group’s influence has grown in myriad ways. For starters, it runs one of Wall Street’s most active energy-trading desks and owns a closely watched commodity index heavily weighted toward crude oil.

Yesterday, it was a different group within the investment bank – the equity analysts – that shook up the commodity markets.¹⁶

While there have been no suggestions of collusion or illegal behavior, it is certainly possible that the forecast of \$105 oil benefited Goldman Sachs’ trading operation. As financial entities have grown in size and are allowed to engage in a broader range of activities, it is increasingly likely that the actions of one group or department will have an effect on an affiliate, or that conflicts of interest will develop.¹⁷ Regulators should have the authority to look across all affiliates of financial companies to monitor potential conflicts of interest and require public disclosure of information on a company’s investments when they are relevant to company pronouncements. For example, a company issuing a bullish forecast for energy prices should reveal its outstanding financial interests in the energy commodities involved.

Impact of Natural Gas Prices on Electricity

High and volatile natural gas prices affect electric utilities directly by raising the price of gas-fired generation. The high prices can have an even larger effect in markets run by RTOs or ISOs. In these markets, day-ahead and real-time electricity prices are set by the hourly market-clearing price, and this price is often based on the high fuel cost of natural gas-fired generation units, particularly during peak load hours.¹⁸ When peak-load natural gas plants set the price of electricity, low-cost coal and nuclear generating units that bid into the market receive prices substantially higher than their operating costs.

¹⁶ Peter A. McKay, “Goldman Analysts Deliver Oil Shock – Prediction of ‘Super Spike’ as High as \$105 a Barrel Puts Jolt in Crude Futures,” *The Wall Street Journal*, April 1, 2005.

¹⁷ For example, in April 2003, following investigations into conflicts of interest between financial companies’ equity research departments and investment banking departments, the SEC reached settlements requiring brokerage firms to change their operations to provide more independence between the two functions.

¹⁸ For example, in the PJM RTO, the marginal generating unit was natural gas for 18 percent of the time in 2001, rising steadily to 31 percent in 2004, before falling to 25 percent in 2005. See Market Monitoring Unit of the PJM Interconnection, “2005 State of the Market Report,” March 8, 2006.

Right now, there are generators that cannot take full advantage of this “dark spread.”¹⁹ Some nuclear and coal-fired generators signed bilateral sales contracts, hedged their sales, or are committed to serving customers under transition plans. These generators can take advantage of high market rates for electricity only to the extent that they have generation in excess of the contracted amounts. According to Merrill Lynch, companies such as Dominion Power, Exelon, FPL Group and Ameren have the potential for significantly higher earnings from their generating facilities if natural gas prices are still relatively high in 2007 when many transition rate plans and hedges end.²⁰

In another example, Reliant Energy recently announced that under its new business strategy the company would not enter into any more forward power sales from its coal plants and would eliminate existing hedges of coal generation. The goal is to enable the coal plants to reap the benefits of higher wholesale prices. The potential gains are large:

Mark Jacobs, Reliant’s chief financial officer, said that with a return to “mid-cycle economics,” his company’s plants could realize gross-margin increases of between \$650 million and \$1.2 billion, including up to \$760 million from its coal plants in PJM and MISO, and \$215 million from its gas plants in those two areas.²¹

High natural gas prices are also having an effect on longer-term electric power markets in RTO regions. Utilities serving end-use customers often want long-term power supply contracts to avoid the higher risk and price volatility of spot markets. However, utilities trying to negotiate long-term bilateral contracts are typically offered terms that reflect the higher market clearing prices the generator can obtain in RTO-run spot markets, even when the generator’s own, lower cost structure bears little relationship to spot market clearing prices. For example, the Michigan Public Power Agency (“MPPA”), which provides power for its 13 member utilities, attempted to negotiate power supply to serve an additional 200 to 250 megawatts of base load expected by 2009 or 2010. According to MPPA, the increase in wholesale power costs since the start of the Midwest ISO caused potential suppliers to reassess their approach to the wholesale market. Suppliers were not interested in a sales agreement with a term of longer than one or two years, and the sales offers MPPA received were based on a market index — either an electricity market index,

¹⁹ The difference between the cost of fuel and the selling price of electricity generated by that fuel is called the spark spread. Spark spreads are typically calculated based on natural gas, but they can be calculated based on any fuel. The premium between the cost of coal or nuclear-based generation and the cost of natural gas generation setting the market price for electricity has been dubbed the “dark spread.” See, for example, Craig K. Shere and Lance Ettus, “The Power of the ‘Dark Spread,’” Calyon Securities, October 6, 2005.

²⁰ “Utility Risks, Opportunities from Higher Fuel Prices Examined in Merrill Report,” *Electric Utility Week*, December 13, 2004.

²¹ “I-Bank Calyon Reacts Positively to Reliant News,” *Electric Power Daily*, February 10, 2006. Note that since its announcement, Reliant has received credit rating downgrades from all three major rating agencies. Moody’s Investors Service said that Reliant’s revised business plans “significantly increase the operating risk profile of the company and its cash flow variability without any corresponding improvement to near-term financial metrics.” See “Moody’s Downgrades Ratings For Reliant Energy and Affiliates,” Moody’s Investors Service, March 13, 2006.

typically based on a locational marginal price (“LMP”), or a natural gas index with a conversion factor.²²

Industrial customers can have the same problem. Alcoa’s Eastalco aluminum smelter in Maryland has stopped manufacturing aluminum – and reduced its workforce by 500 employees²³ – because the only power available is twice the price of its expiring contract. According to the company, the price is based on peak-load gas-fired generation:

However, the effect of the deregulated market structure in Maryland has been to decouple load from the resources used to serve it, so that what Alcoa is now being offered is essentially electric power from gas-fired peaking units, which is much more expensive. The coal-fired base load unit power that Eastalco formerly received now has the opportunity to receive LMP pricing by selling wholesale into its local node completely divorced from Eastalco or any other specific load (customer).²⁴

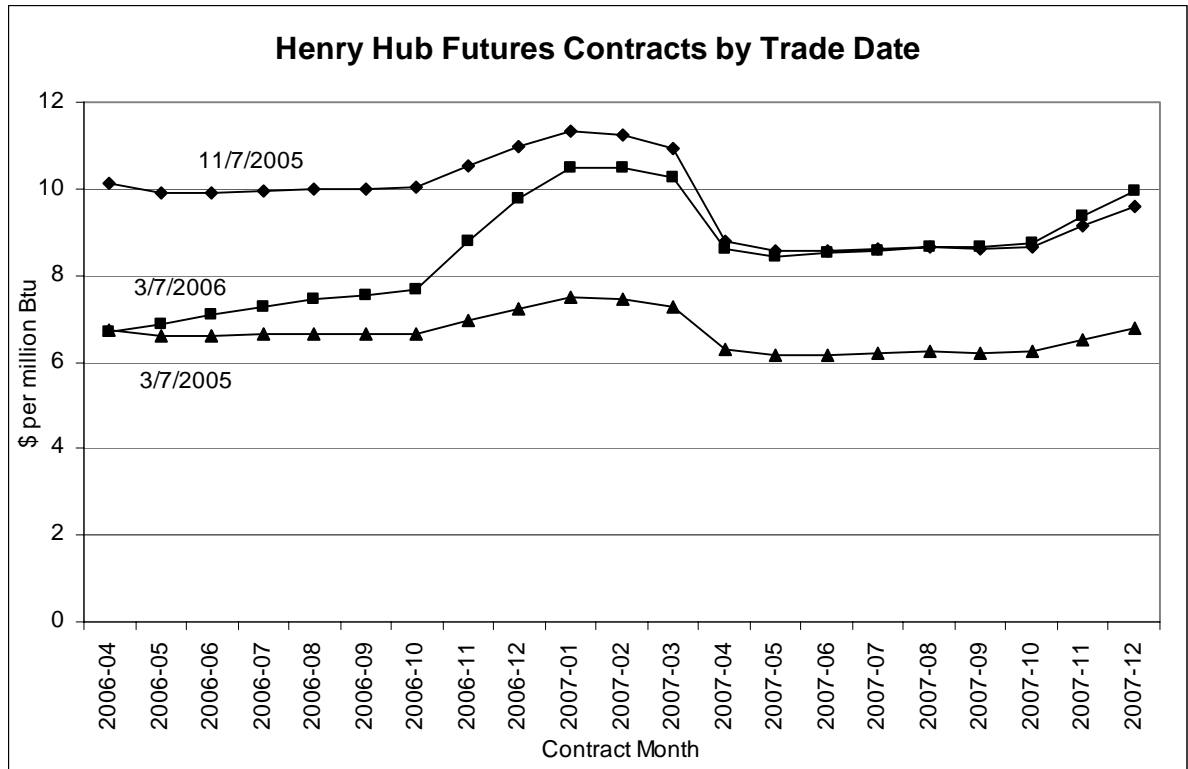
The volatility of natural gas prices also affects electricity prices because price volatility adds to market risk, and prices rise when the market’s assessment of risk rises. This risk premium is one reason that prices for natural gas futures contracts may remain high even when there is a drop in the spot price. If power suppliers use natural gas futures prices as a basis for establishing their electricity contract offers, their sales prices will include this risk premium.

The risk premium has risen substantially since the fall 2005 hurricanes, as indicated in the following graph comparing Henry Hub futures prices on three different trade dates for the contract months of April 2006 through December 2007. On March 7, 2005, the price for these contract months averaged \$6.65 per MMBtu, with slightly higher prices for the 2006-2007 winter months. Contracts traded on November 7, 2005 showed the effects of Hurricane Katrina and Hurricane Rita, with prices \$2.50 to \$3.50 per MMBtu higher than the 3/7/2005 prices for each contract month. Contracts traded on March 7, 2006 showed the effects of the warm 2005-2006 winter as prices for the 2006 contract months are much lower than the 11/7/2005 prices. However, the 3/7/2006 prices for the 2007 contract months closely match the higher 11/7/2005 prices and remain about \$2.50 to \$3.00 per MMBtu above the 3/7/2005 prices. This upward shift of the futures curve can be thought of as the market’s assessment of risk.

²² Comments of the American Public Power Association in Docket No. AD05-17-000, “Electric Energy Market Competition Task Force,” before the Federal Energy Regulatory Commission, November 2005, p. 26.

²³ “Alcoa Eyes Coal to Reopen Maryland Plant,” *Electric Power Daily*, March 9, 2006. The article also discusses Eastalco’s proposal of a public-private venture with the State of Maryland to develop a coal gasification project. The state’s role would include financing.

²⁴ Comments of Alcoa Inc. in Docket No. AD05-17-000, “Electric Energy Market Competition Task Force,” before the Federal Energy Regulatory Commission, November 2005, p. 11.



Source: NYMEX daily closing prices for Henry Hub natural gas futures, as compiled by Energy Velocity.

In addition, electricity price contracts negotiated during periods of high natural gas prices can be a gamble that the utility loses, as shown by the experience of Connecticut Light & Power (“CL&P”) last fall. In December 2005 the Connecticut Department of Public Utility Control (“DPUC”) agreed to a 22.4 percent rate increase for CL&P customers, based on power supply bids received by CP&L in November when Henry Hub natural gas spot market prices rose to almost \$12 per MMBtu. At the time of the DPUC approval, analysts were predicting additional large increases in the price of natural gas if the winter were cold. Rather than gamble on spot market prices or another round of bidding, the DPUC approved the one-year rate increase. Natural gas prices subsequently fell, but CP&L customers are stuck with expensive power contracts for 2006.²⁵

Under current market conditions, coal and nuclear plants, many of which have already recouped their capital costs from regulated customers either in the utility rate base or via stranded cost recovery, can receive huge profits once they are able to sell power at market-based rates. As described in the following section, natural gas prices are expected to remain high for several years, so a mechanism is needed to encourage long-term electricity contracts that reflect operating costs and a reasonable profit, rather than the spot market price of natural gas.

²⁵ Paul Marks, “Locked into High Prices: Setting Electric Rates A Gamble; Cold December, Warm January Change the Odds,” *Hartford Courant*, February 9, 2006, published on www.courant.com.

Natural Gas Prices in the Longer Term

The natural gas supply bubble, which kept price volatility in check and prices low, was over by the late 1990s, and it is unlikely that Henry Hub spot prices will return to the \$3 to \$4 per MMBtu range seen as recently as mid-2002. After Hurricane Katrina, spot prices spiked to over \$15 per MMBtu, but the mild winter weather in 2006 caused natural gas prices to fall back to the \$6 to \$8 per MMBtu range experienced in the first half of 2005. Analysts expect that long-term supply and demand factors will keep prices in this range – or higher – over the next several years. EIA, in its March 2006 *Short-Term Energy Outlook*, predicted average Henry Hub spot prices of \$7.87 per MMBtu for 2006 and \$8.49 per MMBtu in 2007.²⁶ FERC staff's February energy market assessment noted that futures prices indicated that the current natural gas prices are "about as low as they are likely to be for the remainder of the decade."²⁷

The belief that natural gas prices will remain high is partly based on the historical relationship of natural gas prices and oil prices. The two fuels are substitutes in some uses, and while there are now fewer applications that can switch between fuels, there still appears to be a price relationship. One recent study has shown a continued strong correlation between crude oil and natural gas prices once normal seasonal variations in natural gas prices and the amount of natural gas in storage are included in the analysis.²⁸

The demand for oil is growing worldwide, fueled by increasing standards of living in countries such as China and India. Current oil supply is tight, and doubts about future supply keep upward pressure on prices. Causes of uncertainty include:

- The level of oil reserves;
- The extent to which production capacity in the Middle East can be increased;
- Growing depletion rates of reserves;
- The cost of unconventional oil production;
- The significant shortfall in exploration and production investment, including oil rigs, tankers, and refinery capacity;

²⁶ EIA forecast prices were presented in \$ per million cubic feet ("MCF"). APPA converted them to \$ per MMBTU using a conversion rate of 1 MCF = 1.03 MMBtu.

²⁷ FERC Staff presentation, "Winter 2005-2006 Energy Market Update," at FERC's February 16, 2006 Open Meeting, available at the FERC Web site: www.ferc.gov.

²⁸ Stephen P.A. Brown, "Natural Gas Pricing: Do Oil Prices Still Matter?" *Southwest Economy*, Issue 4, July/August 2005, Federal Reserve Bank of Dallas. The study also shows that neither of the two common rules of thumb comparing \$/barrel of West Texas Intermediate crude oil to \$/MMBtu of Henry Hub natural gas ('10 to 1 ratio' and '6 to 1 ratio') is useful. (The '6 to 1' ratio means that oil and natural gas prices are equal once the oil price is converted to \$/MMBtu.)

- Political instability in the Middle East; and
- The potential for terrorists to disrupt the supply chain.

Note also that the Organization of the Petroleum Exporting Countries (“OPEC”), which typically relies heavily on oil revenues, has an interest in keeping prices high. Thus these countries will attempt to limit expansion of production facilities only to levels that will maintain a reasonably high price.

The trend of rising natural gas prices over the past several years reflects both the rise in oil prices and concerns over the supply of natural gas. Demand for natural gas in the U.S. will grow in the residential sector, as population increases, and in the electricity sector. The key questions are whether there will be an adequate supply of natural gas to meet the growth in demand and what the supply sources will be. The credit ratings agencies have summarized some of the longer-term supply/demand issues.

According to Fitch:

In Fitch’s view, natural gas prices will remain above historical levels over the next several years, reflecting difficulties in developing new domestic supply sources, steeper decline rates of existing resources, global competition and limited liquefaction and shipping capacity for liquefied natural gas (LNG), and projected rising consumption for electric generation.²⁹

According to Standard & Poor’s:

The cost to drill new gas wells is climbing, gas well productivity is falling, and drilling rigs and trained personnel are in short supply. On the other side of the equation, demand for natural gas continues to increase despite price increases, which could accelerate if the electric utility industry burns more gas until it can build coal and nuclear plants. Moreover, given the disruptions caused by Katrina and Rita, it is conceivable that markets may begin pricing an extra premium into natural gas, much as many believe international oil markets have done with a supposed “terror premium.” Much of the key supply, processing, and distribution infrastructure is concentrated in the Gulf of Mexico and will always remain vulnerable to force majeure weather events.³⁰

Faster depletion of existing natural gas resources means that more wells must be drilled just to hold production constant. Production is now moving towards more costly recovery areas and more costly extraction processes. As shown in the following chart, the fastest

²⁹ Fitch Ratings, “U.S. Public Power 2006 Outlook: Stable, But Are There Cracks in the Armor?” published February 15, 2006.

³⁰ Standard & Poor’s, “Katrina and Rita Pressure Natural Gas Model; U.S. Infrastructure Vulnerability Exposed,” *Credit Week*, October 19, 2005.

growing producing areas are Wyoming and Colorado, while Louisiana and Federal offshore production has declined.

Wet Natural Gas Production, 1995 - 2004

(in trillion cubic feet)

	<u>1995</u>	<u>2004</u>	<u>Percent Change</u>
Texas	5.11	5.66	10.8%
Federal Offshore	4.67	4.01	-14.0%
Oklahoma	1.66	1.66	-0.2%
New Mexico	1.48	1.63	10.3%
Wyoming	0.84	1.59	89.4%
Louisiana	1.50	1.36	-9.5%
Colorado	0.54	1.09	101.1%
Kansas	0.71	0.40	-43.1%
Other States	2.36	2.61	10.6%
US Total	18.87	20.02	6.1%

Source: Energy Information Administration, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2004 Annual Report, and Natural Gas Processing: The Crucial Link Between Natural Gas Production and Its Transportation to Market.

Greater reliance on Western production will require additional infrastructure to bring the product to market. For example, three oil companies are working on a proposal to build a natural gas pipeline from Alaska’s North Slope to Midwestern states. The estimated cost is \$20 billion.³¹

Virtually all Federal offshore production – the second largest source of U.S. production – occurs in the Gulf of Mexico. Costs are increasing there as well, as production moves from the close-to-shore, shallow-water fields to development of deep-water fields, which require larger-scale operations and greater investment. In 1992, 3.6 percent of federal offshore production was in deep-water fields (at depths greater than 200 meters). This figure rose to 31.5 percent in 2004. Reserve levels show a similar pattern: 12.1 percent of federal offshore reserves were at depths greater than 200 meters in 1992, compared to 44.5 percent in 2004.³²

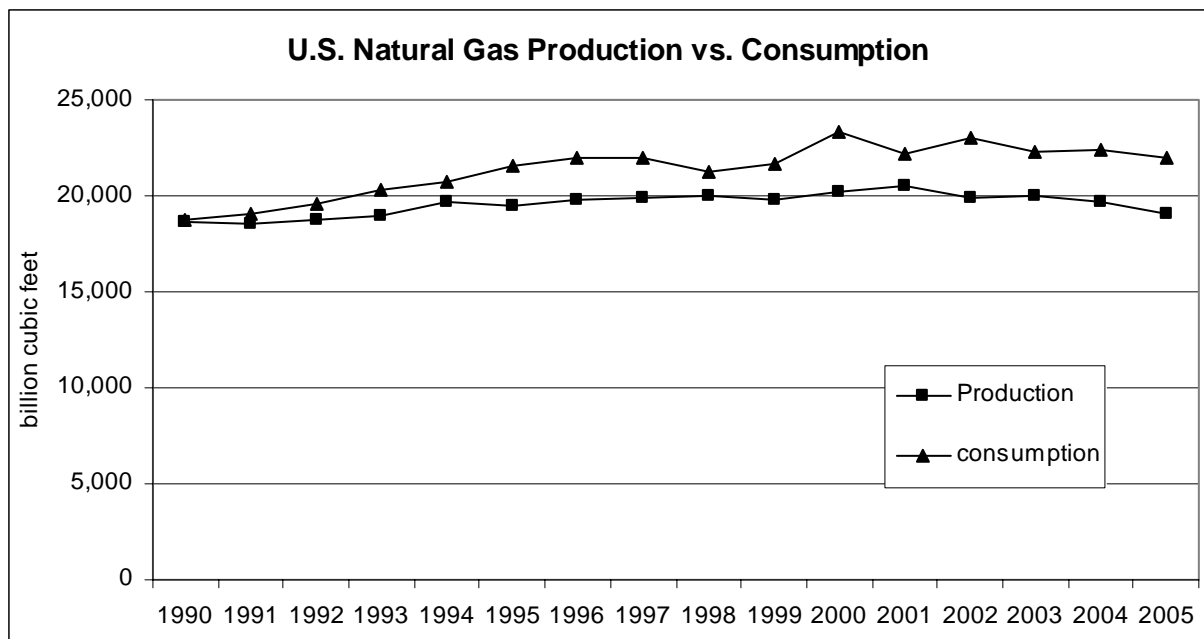
In addition, the gulf area has a tremendous amount of natural gas infrastructure that is vulnerable to hurricanes, including drilling rigs, gathering pipelines, and onshore processing facilities and delivery pipelines. Scientists studying hurricane activity in all tropical ocean basins since 1970 found increasing global sea surface temperatures and an

³¹ The Associated Press, “Alaska and Oil Companies Reach Gas Pipeline Deal,” published at www.nytimes.com by *The New York Times*, February 22, 2006.

³² Energy Information Administration, “U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2004 Annual Report,” Table D9, published November 30, 2005.

increase in the number of Category 4 and Category 5 hurricanes. The percentage of Category 4 and Category 5 hurricanes increased in every basin.³³ Given the strong hurricane seasons of 2004 and 2005 and the possibility that the recent trend of more intense hurricanes may continue, investment in this generally capital-intensive, large-scale natural gas infrastructure becomes a riskier proposition. Thus development of natural gas projects in the gulf might proceed more slowly and require greater investment incentives to offset the higher perceived risk.

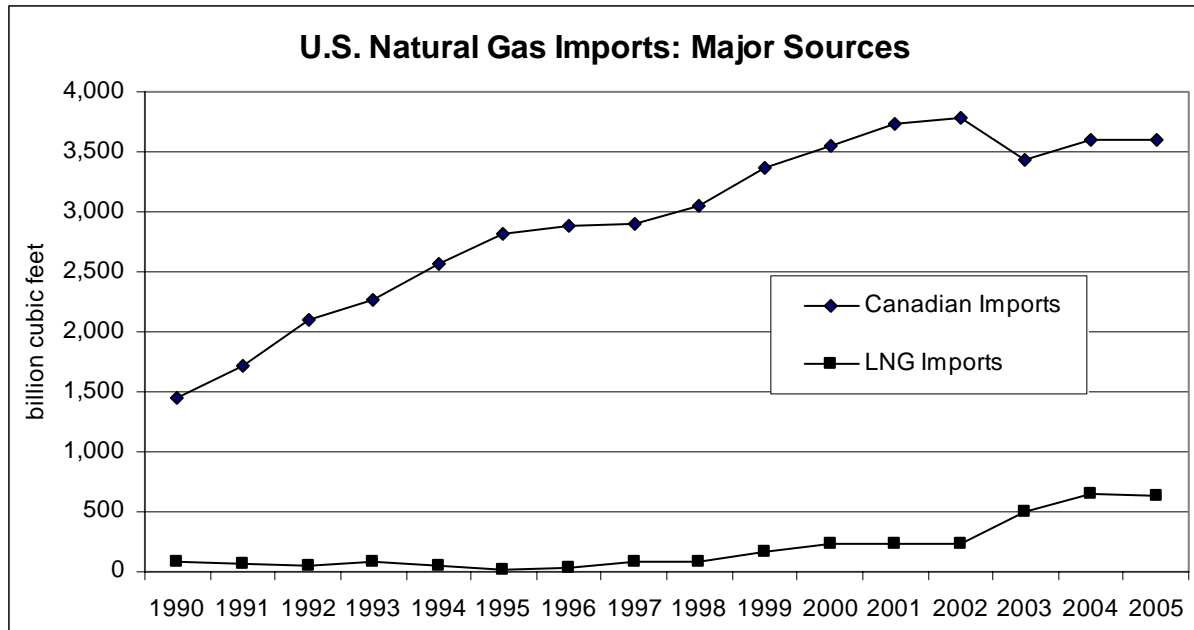
While U.S. production of natural gas rose by only 2.5 percent between 1990 and 2005, consumption grew by 17.4 percent over the same time period. By 2000, the annual gap between domestic production and consumption was about 3,000 billion cubic feet (BCF), as shown in the following graph.



Source: Energy Information Administration, *Natural Gas Monthly* and *Historical Natural Gas Annual 1930 Through 2000*.

Imports have made up for the shortfall in U.S. production. As shown in the following graph, Canada has been the primary source, with LNG becoming a factor in the last few years.

³³ P.J. Webster, G.J. Holland, J.A. Curry, H.-R. Chang, “Changes in Tropical Cyclone Number, Duration, and Intensity in a Warming Environment,” *Science*, Vol. 309, No. 5742, September 16, 2005, pp. 1844-1846.



Source: Energy Information Administration, *U.S. Natural Gas Imports and Exports: 2004 and Natural Gas Monthly*.

However, Canadian imports have leveled off since the early 2000s and are not expected to increase. In fact, Canada may have less natural gas to export, as Canadian wells are also experiencing higher decline rates, and the Alberta oil sands operations, which consume large amounts of natural gas, are growing in response to high oil prices. The Province of Ontario’s planned phase-out of coal-fired generation may also result in less gas available for export.

With increasing demand, domestic production relatively flat, and limited Canadian imports, the U.S. is looking to LNG imports to add to supply. Several projects to increase capacity at existing LNG regasification terminals are underway, and five new terminals are under construction. FERC has also approved new pipeline projects designed to serve LNG terminals. However, U.S. terminal capacity is not the only concern as to whether LNG imports can make up for potentially large North American supply/demand imbalances. In fact, existing LNG terminals are not operating at anywhere near capacity, and U.S. imports in 2005 were three percent below the 2004 level.

Of equal importance are the limited capacity of liquefaction plants abroad and world-wide competition for the limited LNG supply. As of 2004, there was at least twice as much regasification capacity as liquefaction capacity, making LNG a sellers’ market. Other countries have been willing to sign long-term contracts with LNG suppliers, while most LNG imported into the U.S. moves under short-term arrangements.³⁴ Other countries have also been willing to pay high prices to secure LNG shipments. For example, in

³⁴ Jeffrey Wright, “Winter Energy Market Assessment 2005-2006,” presented by FERC staff at the FERC Open Meeting, November 17, 2005, Transcript, p. 31.

January an LNG shipment originating in Trinidad and destined to the U.S. Cove Point LNG terminal was diverted to Japan. The rumored price for the shipment was \$13 per MMBtu.³⁵

Increased reliance on LNG imports will tie the U.S. natural gas market to the world market and make it more susceptible to supply disruptions and political instability in producing countries. U.S. prices will also be more closely tied to world natural gas prices, as a recent article explained:

At the moment, [March 2006] . . . a United States natural gas future for delivery in February costs \$10.48 per million B.T.U.'s, but a British future for the same time costs the equivalent of \$14.99 per million B.T.U.'s. "If U.K. to U.S. price differentials remain this large," said Mr. [Francisco] Blanch of Merrill Lynch, "then very little gas will head to North America next winter." As more liquefied natural gas supplies become available, and as ports are outfitted to receive such supplies, such a disparity will become more and more unlikely.³⁶

Effective Energy Policies Require a Long-Term Focus

In the short run, high natural gas prices lead to more drilling activity, expanded production capacity and eventually downward pressure on prices. Strong drilling activity and the mild winter helped push prices down over the 2005-2006 winter, but over the longer term, growing world demand for both oil and natural gas, higher cost production, and concerns over the availability of supply should push prices up again. Regulators and legislators must look for long-term solutions and implement steps to reduce demand, increase potential supply, and establish conditions conducive to long-term investment in infrastructure.

Demand reduction measures include energy efficiency and conservation programs – in both natural gas and electricity markets – and investment in a broader mix of electric generating fuels. Policies encouraging clean coal technology, renewable energy and nuclear investment should lead to lower consumption of natural gas by the electric utility industry. A generating mix less reliant on natural gas also has the potential to reduce the number of hours that natural gas prices will set the market-clearing price of electricity, thereby weakening the link between gas and electricity prices in both spot and contract markets.

Supply enhancement measures include technological advancements in the extraction of gas from non-conventional sources, and broader access to gas fields. For example,

³⁵ Jeffrey Wright, "Winter 2005-2006 Energy Market Update," presented by FERC staff at the FERC Open Meeting, February 16, 2006, Transcript, pp 32-33.

³⁶ Floyd Norris, "The Future of Natural Gas Pricing Could Be a Trans-Atlantic Tug of War," *The New York Times*, March 11, 2006.

industrial customers and gas distribution utilities have called for enactment of a provision allowing states to opt out of the federal moratorium on gas drilling along the Outer Continental Shelf. The Minerals Management Service of the U.S. Department of the Interior estimates that there are 62.3 trillion cubic feet of undiscovered conventionally recoverable natural gas in the moratoria areas.³⁷

Investment in infrastructure, whether it is deep-water wells in the Gulf of Mexico, additional pipeline capacity to move the gas from newly developed areas, LNG terminals, storage facilities, or electricity infrastructure, such as clean coal facilities or emissions reduction technology, will only occur if investors believe that their capital can be recouped with a reasonable profit. This requires certainty in the form of long-term contracts or other arrangements.

Capital intensive industries, such as natural gas and electricity, tend to have boom and bust cycles of investment. Rising prices attract new investment, but during the significant amount of time it takes to get new infrastructure built and in operation, shortages and extremely high prices can occur. The large size of the new capital investments then leads to over-capacity, and prices fall again. Investors become wary of the industry, and stay away until price signals are high enough to draw them back. In addition, certain market participants benefit from tight capacity and higher prices, so there are incentives to keep capacity tight. Thus regulators have a large role to play in ensuring long-term solutions to infrastructure needs.

Some of the issues surrounding long-term contracts were aired at FERC's October 2005 conference on natural gas infrastructure. A task force on contracting practices created by the National Association of Regulatory Utility Commissioners and the Interstate Oil and Gas Compact Commission recommended that regulators encourage long-term supply, transportation and storage contracts, and noted that at times it may be crucial to support long-term contracts in advance.³⁸ A spokesman for the investment community discussed the need for long-term contracts in order to move forward with a gas pipeline project and pointed out some of the difficulties in obtaining long-term contracts:

As you can imagine, the suppliers we were speaking to were somewhat reticent to sign up to longer-term transportation agreements. Given the price of natural gas, it's very difficult to fault them for their decision. However, that lack of support makes it very difficult for a project to be completed, which in the longer-term nature of these businesses, would be expected to support their activities as producers.

³⁷ Energy Information Administration, "Overview of U.S. Legislation and Regulations Affecting Offshore Natural Gas and Oil Activity," September 2005, p. 12, citing the Minerals Management Service's mean estimate in 2000.

³⁸ Donald Mason, Commissioner, Ohio Public Utilities Commission, "Conference on the State of the Natural Gas Infrastructure," Federal Energy Regulatory Commission, October 12, 2005, Transcript, pp. 102-103.

Conversely, our LDC [local distribution company] customers certainly did have interest as communicated to us to enter into these long-term contracts but, as has been mentioned before, the regulatory agencies that they reported to and their rate recoveries were generally of an opinion that longer-dated contracts were not particularly supportive for them, so the project ended up not moving forward and I think it's frankly for lack of some of the institutional support at the state level that really would have driven that home.³⁹

Finally, a pipeline company representative stated that the company's current transportation contracts average about three years, while 24 years ago, the average was about 10 to 15 years. Lack of long-term contracts increases the risk:

You can run an IRR [internal rate of return] and assume – let's say you only have a five-year contract – that you have a contract and you'll renew it for 15 years. You're making a big risk assumption – the pipeline is. Pipelines run very long-term economics. If their contracts are very short-term, they've got all the back end risk on the project.⁴⁰

Conclusion

Because of the strong connection between natural gas and wholesale electric prices, the electricity industry has a great deal riding on the long-term behavior of natural gas prices. To achieve price stability in natural gas markets requires implementation of long-term strategies. The strategic actions must encourage the development of domestic production and sufficient energy infrastructure, promote the conservation of resources, and provide adequate oversight of financial traders in energy markets.

³⁹ Michael Walsh, Managing Director, AIG Highstar "Conference on the State of the Natural Gas Infrastructure," Federal Energy Regulatory Commission, October 12, 2005, Transcript, p. 115.

⁴⁰ Scott Parker, President of Gas Pipelines, Kinder Morgan, "Conference on the State of the Natural Gas Infrastructure," Federal Energy Regulatory Commission, October 12, 2005, Transcript, p. 134.