Order Code RL30815

CRS Report for Congress
Received through the CRS Web

Natural Gas Prices: Overview of Market Factors and Policy Options

January 23, 2001

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Summary

Natural gas prices increased steadily during 2000, as demand for gas-fired electric power production grew sharply. When cold winter weather arrived, heating demand – coupled with ongoing electric power demand – drove spot prices up. In one short-lived and isolated episode, gas touched $30 per thousand cubic feet (mcf) – the energy equivalent of $175 per barrel oil.

Residential customers rarely buy spot market gas themselves. At the start of 2001, they were paying just over $9 per mcf for delivered gas on a nationwide average basis, an increase of 39% from a year ago. It is likely that this price will be higher when January 2001 bills are mailed to consumers, as spot market prices have remained high. Most gas supply arrangements only offer short-term protection against price volatility; they ultimately converge on spot prices.

Large commercial, industrial and electric generation consumers generally procure their own gas supplies and arrange for transport. Since they do not have to pay local utility distribution charges, these big users pay less for delivered gas. For 2000, industrial and utility users paid about 40% of residential levels.

Low wellhead prices and deregulated long-distance transport costs led to growing demand during the 1990s. Demand – which grew 36% from its 1986 low – reached a peak in 1996 and 1997. Most notable was demand from gas-fired electric power plants, where consumption rose by almost 50% during the 1990s.

Warmer winters in 1998-99 and 1999-2000 kept gas demand low, and masked a decline in supply; as U.S. gas output fell about 9%, prices remained stable until 2000. Another mitigating factor has been growing imports from Canada, which helped offset most of the domestic output drop. Imports held prices steady into 2000, when the growth in demand interacted with inelastic supply and prices rose sharply. Late-January spot prices are in the $7 to $8 range, plus transportation and distribution charges. If average flowing gas prices converge on spot, current markets suggest that residential prices, for example, could rise by another $1 to $2 per mcf.

How might the present supply-demand relationship be resolved so that prices return to more accustomed levels? On the supply side, it is likely that U.S. production will increase as the number of wells being drilled has doubled during the past 12 months. More output should flow in response to higher prices. More imports of liquefied natural gas (LNG) are being planned at four existing terminals.

With regard to energy policy, the discussion has barely begun. Policymakers may focus on the role of gas in power production, producer incentives – including making more federal lands available and tax incentives – and conservation measures. And the impact of price on demand has not come to its full effect. The combination of increased production and price-induced conservation might balance supply and demand at a more comfortable price level.

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Introduction

Natural gas prices have risen sharply during the past year, following a 15-year period of adequate supply and relatively low prices. That extended period of low prices followed a severe price spike during the late 1970s and early 1980s, when natural gas was thought to be such a finite resource that the federal government began restricting its use. The high prices of the early 1980s led to increased supply and reduced demand, causing prices to fall. Low prices and plentiful supply persisted through the late 1990s, despite growing demand for gas-fired electric power production.

During the 1990s, the total supply of natural gas from U.S. production and imports grew steadily until 1996. Domestic production declined by about 5% between 1996 and 1999, and imports – chiefly from Canada – do not appear to have risen enough to completely make up the difference. Despite the slightly lower apparent supply and underlying demand that may well be growing, prices remained stable until 2000. An imbalance between "normal weather" supply and demand, with accompanying price increases, may have been postponed by rising imports and warm winter weather during the late 1990s.

By the second half of 2000, however, steadily growing gas demand by new gas-fired power plants began to consume the gas supply left over from the warm winter. Much of the supply that might have gone into storage for the current winter was burned. As winter 2000-2001 approached, power demand remained strong and prices began to rise sharply.

How much will prices rise? Late-month 2000 data have not yet been tabulated. Many consumers are using gas acquired by distributors in 2000, at what amounts to last year's prices. Spot market transactions at very high prices are known to have taken place, but so far they represent incremental purchases. The question becomes how long will it take for the average price of flowing gas to catch up with the spot market's price leadership. And what might the average price of flowing gas be as the peak winter season winds down?

This report describes the market factors that are influencing the current natural gas situation, outlines the structure of the natural gas industry, and discusses policy options for Congress. New sources of supply will be important in bringing prices down in the long term, but not for winter 2000-01. How quickly such supplies can be brought on line is difficult to predict. Demand-side options – especially price-induced conservation – may also help in the long run.

Natural Gas Industry Structure

Natural gas is purchased by residential consumers in a manner different from that of larger industrial and commercial users. Nearly all homeowners buy gas from a state-regulated local distribution company (LDC), while larger customers generally purchase gas directly from producers or wholesale marketers. For a typical residential or small commercial consumer, gas bills consist of three components: the wellhead price, the long-distance transportation cost, and local distribution costs, which are discussed below in turn.

Most large industrial and commercial gas users and electric power generators buy gas from producers or market makers and arrange pipeline transportation themselves. They may be located adjacent to a long-haul pipeline route, own a connecting pipeline, or have an arrangement for delivery via an LDC.

Wellhead Price

Natural gas producers find reserves, drill wells, and produce and gather the gas and put it in marketable condition. Producers' prices are determined in the marketplace by the interaction of supply and demand. Federal price controls existed for a number of years, but for the most part ended in 1985. The small amount of gas that remained under controls was deregulated in 1989.

Producers sell gas to a variety of ultimate consumers as well as broker/trader intermediaries, gas "clearing houses," and other entities playing a market maker role. Gas ultimately sold to consumers moves under a variety of contractual arrangements that fall into two broad categories. Gas may be sold under contract in which amounts, duration, and prices are specifically spelled out. Or gas may be sold on the spot market, where the owner auctions a package of gas at a specific location for the price prevailing at that time and place. There are numerous trading centers at various pipeline system nodes around the nation, and during times of market volatility they can be the scenes of frenetic trading activity for gas that is promptly available.

Most gas moves under contract of one sort or another. But contracts are either finite in duration or provide for periodic price adjustment to reflect market conditions. It is the exception rather than the rule for a gas contract to provide below market prices for a sustained period.

Long-Distance Pipeline Transportation

Long-distance pipeline transporters are the next step from gas field to consumer. Under Federal Energy Regulatory Commission (FERC) Order 636, most pipeline rates are set based on competitive forces in the marketplace. While rates are not regulated directly, FERC reviews the filed tariffs of pipeline companies to ensure that they are "just and reasonable" as well as nondiscriminatory. In the exceptional case of pipeline systems without competition, FERC may set rates, using a traditional public utility accounting regulatory format.

Buyers and sellers arrange for pipeline capacity to transport their gas to market; the purchaser pays the pipeline its transport tariff. Gas buyers may also contract for ancillary services – such as storage (often pipeline owned) – en route.

In some transactions, pipelines deliver gas to customers located directly along the pipeline right of way or near enough to a customer-owned pipeline. In other cases, gas is delivered to a local distribution utility from the long-haul pipeline dropoff point (often referred to as the city gate).

Local Distribution

The local distribution company (LDC) operates an intrastate utility – regulated by the state public utility commission – that delivers gas from the city gate to residential, commercial, and industrial users along its route. It usually purchases gas for resale to residential consumers. Generally speaking, non-residential LDC customers may also buy gas – not just transportation of gas they have bought on their own – from the LDC; for some, this is an attractive alternative to procuring gas supply and arranging transport on their own.

An LDC's rates and tariffs are formulated by the state regulatory body to recover the gas utility's operating and capital costs and its gas acquisition costs, and to earn a return on capital invested in plant and equipment. Gas acquisition cost recovery is typically handled through a mechanism called the purchased gas adjustment (PGA) clause, which passes through increased (or decreased) gas acquisition costs to gas customers. During times of rapidly rising gas prices, the PGA can become a focal point of consumer concern, as it has this winter.

Current Price Trends

The last half of 2000 and the beginning of 2001 have seen a sharp escalation in gas prices. Residential prices have caused a great deal of concern among residential customers. According to the U.S. Energy Information Administration (EIA), residential gas prices have risen from an average of $6.51 per mcf in December 1999 to $9.04 on January 4, 2001, an increase of 39%. Higher prices – coupled with higher consumption due to colder winter weather – have resulted in much higher heating bills. EIA's breakdown of recent residential gas prices shows that only 35% ($3.16) of the $9.04 average price is for the gas itself, and 47% ($4.25) for LDC tariffs. The remaining 18% ($1.63) is for long haul-transport.[1]

But these data may lag fast-moving developments in gas markets. Today's prices – for which bills have not yet been mailed – may be higher than they were a few weeks ago. Spot market reports from nodal trading points around the country have commodity prices – without distribution or substantial transport costs – in the $8.00 to $10.00 per mcf range. Very short-term readings have been as high as $39.00 at the New York city gate on December 29, 2000; other trades at pipeline systems have

[1]EIA, *Natural Gas Status Report*, January 18, 2001

recorded similar, transitory pricing situations. Southern California – where gas demand is especially high because of electric power needs – has also experienced such price episodes.

Table 1 shows producer gas prices at the wellhead as well as prices for other consumer classes. Because year 2000 data are year-to-date as of September, and do not reflect substantial late-year price increases, these data are historical and may understate current gas prices.

Table 1. Natural Gas prices by Customer Class, 1995 to 2000

($/Mcf)

Year	Wellhead Price	Residential	Commercial	Industrial	Electric Utility
1995	1.55	6.06	5.05	2.71	2.02
1996	2.17	6.34	5.40	3.42	2.69
1997	2.32	6.94	5.80	3.59	2.78
1998	1.94	6.82	5.48	3.14	2.40
1999	2.17	6.69	5.33	3.10	2.62
2000 (11 months)	3.35	7.13	5.64	3.96	3.76

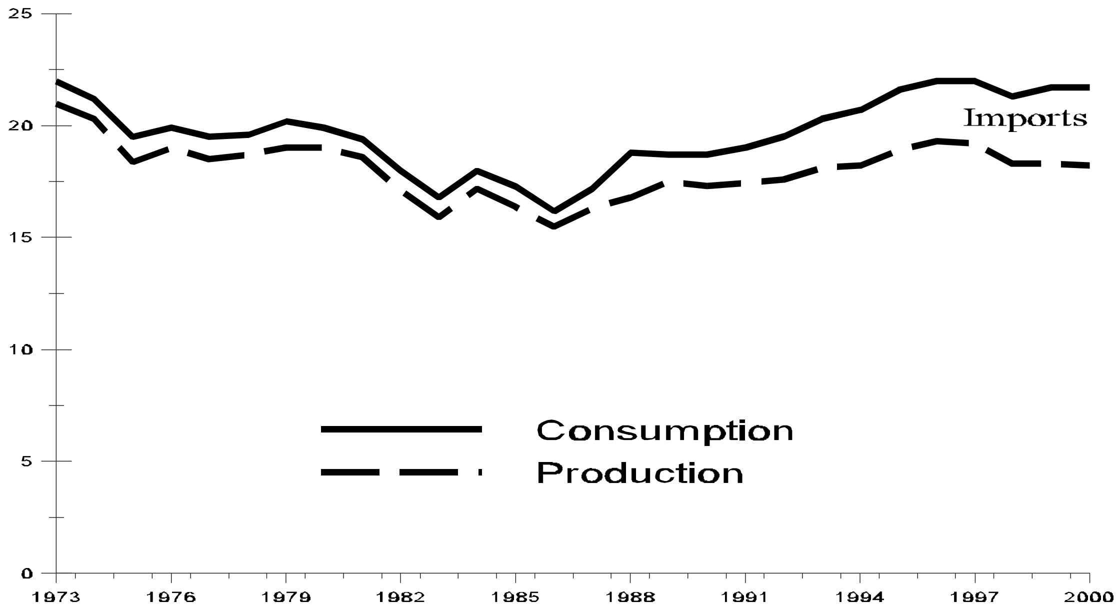
Source: EIA *Natural Gas Monthly,* Table 4.

These data do show 5 years of price stability, running through 1999; they do not show a preparatory price ramp to the current situation. Even year 2000 data do not fully encompass real-time pricing. For all users, each month's gas bill represents completely new and unexpected pricing.

Gas Demand

U.S. natural gas consumption trends have changed direction dramatically since 1973. Figure 1 traces a 25% decline in consumption from 1973's 22.0 trillion cubic feet (tcf) to a bottom of 16.2 tcf in 1986. The downtrend in gas consumption then reversed, with rising consumption reaching its historic (1973) peak in 1996 and 1997. Between 1986 and 1996/7, consumption increased 5.8 tcf (36%). Virtually half of increased demand was supplied by imported gas, which rose by 2.8 tcf between 1986 and 1997. During 1998 and 1999, gas consumption declined slightly from its highest levels, a likely result of warm winter weather.

Figure 1. Natural Gas Consumption Imports and Production, 1973 - 2000 (tcf/yr)



Source: EAI, *Monthly Energy Review*, Table 4.2.

Table 2 shows an overview of gas demand in the main consuming sectors, contrasting use in 1985 with 1999's consumption and identifying the high growth sectors since the recovery of gas demand. Of special note is the 3.4 tcf increase in industrial consumption, because it includes the fast growing non-utility power generating industry.

Table 2. Gas Consumption by Sector (tcf) - 1985 and 1999 Compared

	Residential	Commercial	Industrial (including non-utility generation)	Electric Power Generation (by utilities)
1985	4.3	2.3	5.6	2.6
1999	4.7	3.0	9.0	3.1
% Change	9.3	30.4	60.7	19.2
Change (Tcf)	0.4	0.7	3.4	0.5

Source: EIA, *Natural Gas Annual*, 1999, and author's calculations.

In 1989, DOE began to account for gas consumed to generate electricity as a separate item so that all gas used to generate electric power would be shown in the same data series. Table 3 shows the growth of non-utility (unregulated) and utility gas-fired power plant consumption.

Table 3. Natural Gas Used to Generate Electric Power, 1989 and 1999
(tcf)

Year	Total	Regulated Utility	Non-regulated Generator
1989	4.0	2.8	1.2
1999	5.9	3.1	2.8

Source: EIA, *Natural Gas Monthly*, Tables 4.5 and 7.6

Between 1989 and 1999, gas used in power production in unregulated and utility plants grew from 4.0 tcf to 5.9 tcf, a jump of 1.9 tcf. By 1999, independent power producers' consumption accounted for 47% of the gas used to produce electric power. Further EIA data for the first 9 months of 2000 show that independent power producers' gas use was 37% higher than the comparable 1999 period.

High rates of growth for unregulated power generators' gas consumption are an important consideration in evaluating future gas demand. Many firms have built combined-cycle gas turbine plants during the past 6 or 7 years and they have come on line just in time to supply increased electric demand. A primary source of electricity to meet growing power demand, these plants' call on natural gas supplies will likely grow in the next several years. In fact, EIA data show that gas fired power production – including the output of cogenerators – provided 17% of total-kilowatt hours produced in 1999; in 2005 it is forecast to have grown by 42%, providing 22% of the nation's electricity.[2]

While consuming a sizable part of U.S. gas supply, natural gas-fired generation has a number of benefits. Among them is the fact that gas-fired plants can be constructed faster than other power facilities, an advantage in this time of power shortages. Additionally, gas plants have environmental advantages, especially when compared to the alternative of coal plants. They produce fewer emissions of both pollutants and greenhouse gases.

Gas Supply

Most U.S. natural gas supply comes from domestic sources, either from on-shore wells or the outer continental shelf. In addition to domestic production, the United States imports nearly 16% of its current gas supply by pipeline from Canada and liquefied natural gas (LNG) from Algeria and Trinidad. Growing international trade in LNG could point toward a future world market for natural gas, as currently exists for crude oil.

[2]EIA, *Annual Energy Outlook, 2001*. Table 8A

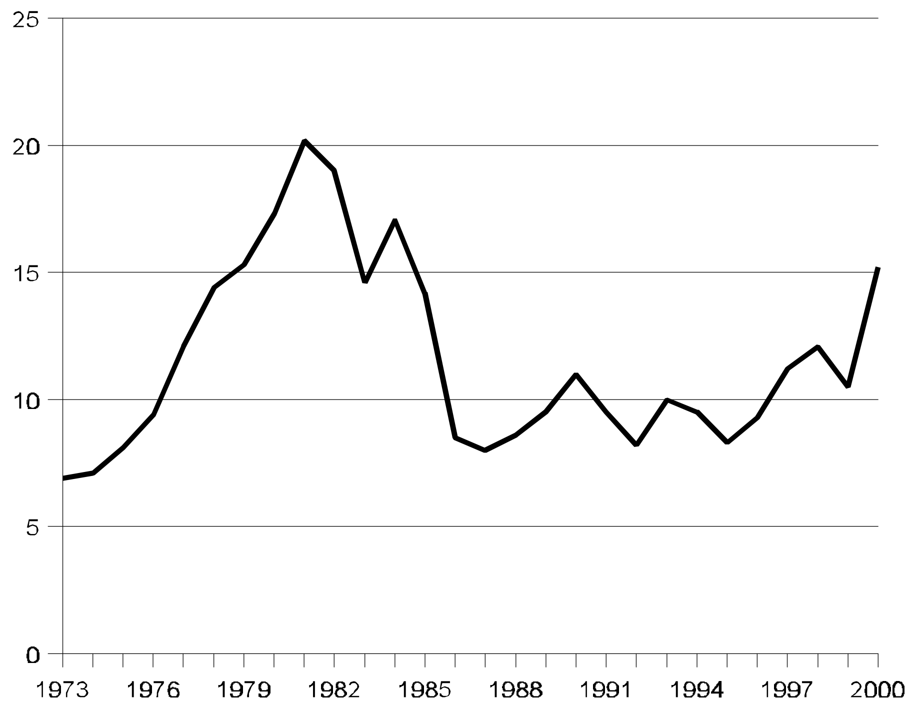
Domestic Reserves and Production

Increased demand has steered the policy debate toward discussion of proven reserves and what sort of incremental demand might be supported by the nation's resource base. Proven gas reserves have held steady between 1989 and 1999, starting and ending the period at 167 trillion cubic feet,[3] an amount equivalent to slightly less than 9 years of production.

EIA contends there is much more gas to be found in the United States, and that those discoveries will sustain the current level of proven reserves and support output for many years. It estimates that technically recoverable resources amount to 1,279 tcf (the equivalent of 58 years of consumption at current rates) in the lower 48 states and Alaska.[4]

While gas may be produced in conjunction with crude from oil wells, gas largely comes from gas-only wells. Figure 2 shows the trend in the number of gas wells drilled since 1973.

Figure 2. Natural Gas Wells by Year
(thousands of wells)



Source: EIA, *Monthly Energy Review*, Table 5.2.

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[3]EIA, *U.S Crude Oil, Natural Gas and Natural Gas Liquids Reserves, 1999. Annual Report*, Table 1.

Drilling activity picked up after 1973 as gas prices rose and remained high until oil and gas prices dropped in 1985. Gas drilling did not pick up again until the mid-1990s. Despite a setback in 1999, drilling remained strong through 2000, with higher prices driving the number of wells back to pre-1985 levels. The number of active rigs drilling for gas increased from 496 in 1999 to 706 for the first 11 months of 2000.

With gas well drilling headed back up to levels not seen for 15 years, it would seem as if there were adequate incentives and enough attractive prospective territory to foster a high level of drilling activity. Given that the amount of drilling in the last half of 2000 was twice that of the first half of 1999, much of the increased gas supply resulting from those efforts should be available on markets sometime during 2001.

Other Supply Options

Other potential sources of increased supply include additional LNG imports and production of Alaskan gas. LNG imports are already growing, sparked by higher prices. There are four receiving facilities in the United States, located at Boston MA, Cove Point, MD, Elba Island, GA, and Lake Charles, LA. Cove Point and Elba Island are currently mothballed. Most current interest centers on Elba Island and Lake Charles. Cove Point is reportedly attempting to start up in 2002, but details are sketchy.

Platt's Oilgram News reports that El Paso Energy is currently seeking approval to reopen the facility in Georgia, which has been shuttered since 1980.[5] The terminal was included in the purchase of SONAT by El Paso in 1999. Were FERC to fast-track the regulatory process, El Paso claims that it could be receiving spot cargoes by year-end; the plant is scheduled to receive its first imported gas from Trinidad in 2002. El Paso has also applied to FERC to increase capacity.

Trunkline, operator at Lake Charles, has expressed interest in expansion also, having been able to procure spot cargoes from Qatar, Algeria, Nigeria, Australia, Oman and Abu Dhabi. With world LNG trade in its early stages, it seems as if recent energy market conditions have given the infant industry a boost.

One potential barrier to early startups is a possible shortage of LNG carriers. Worldwide interest in LNG is so strong that the current fleet, which includes many aging vessels, is stretched thin.

Alaskan natural gas could be a longer-term supply option. Construction of a gas transport system to bring Alaskan gas to the lower 48 states would take several years once a decision were made to move forward. Substantial proven reserves are said to exist in and around the Prudhoe Bay field that produces a large share of Alaska's North Slope (ANS) crude. These reserves are currently classified as non-commercial because the gas cannot be transported to markets.

On September 18, 2000, the Senate Energy Committee held oversight hearings on alternative routes to bring the stranded gas to market. While formal proposals have not been

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[5]Platt’s Oilgram News, *U.S. LNG Operators Look to Grab Bigger Piece of Market*, December 27, 2000.

announced by the firms owning production rights to ANS gas, three routes have been discussed. Two would go overland, crossing Canada and intersecting with its gas pipeline system. These plans would bring Alaskan – and perhaps more Canadian – gas to the U.S. upper Midwest. Also under discussion is an LNG route along the Trans-Alaska Pipeline System right of way that would bring gas to liquefaction facilities at the port of Valdez for ocean transport to the West Coast ports or abroad.

The Alaska gas proposals need FERC approval, a right of way across federal lands, and approval of Canadian governmental bodies if the transit Canada. Congress may be called upon to pass legislation granting a right of way, as was done with for the TransAlaska Oil pipeline System, when it enacted the Trans Alaska Pipeline Act of 1973.

In addition to these hurdles, any Alaska gas project viability would depend on gas prices remaining high in end-user markets.

General Policy Options

Up to this point, gas price hikes are just beginning to flow through to many end users, and the full impact of this winter's higher prices has not been fully realized. As the end of January 2001 approaches, and gas bills covering a period of cold winter weather arrive, the intensity of public concern felt will increase and the policy debate will likely heat up. Increasing intensity in the policy discussion will likely identify more policy options – and more tightly focus the details of those being discussed – to deal with what could become a crisis. But at this writing, there are scant options under discussion for dealing with the gas price problem in the near-term.

Looking toward what might be debated in this Congress, the one short-term option that may receive legislative attention is additional funding for the Low Income Home Energy Assistance Program (LIHEAP),[6] which may be needed because of both higher energy prices and cold weather. Whether further incentives to drill for gas–inherently longer term measures – are considered may be affected by strong response in the number of gas wells being drilled to date. It may well be that such an initiative is considered later in the debate.

In a similar vein, Congress may debate opening federal lands not now available for exploration. These could include areas on-shore in the lower 48-States, as well as Alaska, possibly the Arctic National Wildlife Refuge (ANWR), and off-shore areas not now available for leasing. Alaskan gas supply requires construction of a transport system, crossing federal and possibly Canadian land.

Additionally, the Department of Interior will begin work on the next 5-year plan for leasing on the outer continental shelf (OCS). It will be receiving input – and revisiting leasing policy – regarding which tracts should be made available for exploration during 2003 to 2008.

[6]For more information see CRS Report 94-211: *The Low-Income Home Energy Assistance Program(LIHEAP)*, by Melinda Gish. Updated January 8, 2001

The LNG option may also be addressed. Among the policy options are fast-tracking regulatory approval for the refurbishing and expansion of the four existing facilities. A related issue is the construction of new, specialized LNG vessels, perhaps by U.S. shipyards.

Finally, measures regarding conservation, electric power plant gas use and gas producer issues such as a windfall profit tax at the wellhead could figure in the policy discussion.

In closing this policy summary, it should not be overlooked that the confluence of market forces may well resolve the gas price problem. There is some chance that more production will result – perhaps by next winter – from the step-up in drilling. Taken together with price induced conservation and some extra imports, this might be sufficient to balance supply and demand at a more comfortable price level.