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REPORT BY THE U.S.

# General Accounting Office

## Natural Gas Price Increases: A Preliminary Analysis

Natural gas prices in many cities are expected to increase substantially this winter.

This preliminary analysis addresses

--how much prices have increased since 1970 to residential, industrial, and other users nationwide and to residential users in selected cities;

--what factors have affected the prices paid by natural gas pipelines, distributors, and end-users; and

--whether there is a balance between natural gas production and consumption.

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UNITED STATES GENERAL ACCOUNTING OFFICE

GAO/RCED-83-76

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UNITED STATES GENERAL ACCOUNTING OFFICE
WASHINGTON, D.C. 20548

RESOURCES, COMMUNITY, AND ECONOMIC DEVELOPMENT DIVISION

B-210099

The Honorable Thomas F. Eagleton
United States Senate

The Honorable Michael D. Barnes
House of Representatives

The Honorable George Miller, et al.
House of Representatives

This report is in response to your separate, but similar, requests for information explaining recent natural gas price increases and simultaneous reports of "excess" natural gas supplies. This report is not an evaluation of any agency's performance and contains no recommendations.

This is a preliminary report, and we are continuing our efforts in this area. We did not obtain agency comments on the matters discussed.

We are sending copies of this report to the Secretary of Energy and the Chairman, Federal Energy Regulatory Commission.

J. Dexter Peach
Director

COSIGNERS OF REQUEST LETTER

FROM REPRESENTATIVE GEORGE MILLER

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House of Representatives

The Honorable George E. Brown, Jr.
House of Representatives

The Honorable Phillip Burton
House of Representatives

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House of Representatives

The Honorable Pete Stark
House of Representatives

REPORT OF THE GENERAL
ACCOUNTING OFFICE

# PRELIMINARY ANALYSIS OF NATURAL GAS PRICE INCREASES

## D I G E S T

Reports that the price of natural gas will increase substantially this winter have received widespread attention. In response to congressional requests, GAO has prepared a preliminary analysis, which covers

--how fast prices have increased;

--why prices have increased; and

--whether there is an "excess supply," and if so, how it developed.

## STRUCTURE AND REGULATION OF THE NATURAL GAS INDUSTRY

Natural gas--about 95 percent of it produced domestically--accounts for over 25 percent of the energy consumed in the United States. Industrial use accounts for 41 percent of all gas; residential, for 24 percent; electric generation, for 19 percent; commercial for 13 percent; and and other uses, for 3 percent.

The natural gas industry is comprised of three sectors--production, transmission, and distribution--which are physically interconnected by a network of pipeline and main throughout the United States. At one end of the network are thousands of companies which explore for, drill for, and produce gas. Since enactment of the Natural Gas Policy Act of 1978, all production has been subject to Federal price regulation. The act established various pricing categories based on such factors as where and when a well is drilled.

At the other end of the network are almost 1,600 distribution companies, usually local public utilities, serving their own market areas and under the jurisdiction of State or local regulatory bodies. The connecting transmission network includes 129 interstate pipeline companies operating under Federal jurisdiction, plus many intrastate pipelines which are generally regulated under State laws. (See pp. 1 to 3.



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HOW MUCH HAVE GAS PRICES INCREASED?

Prices to all types of users increased at an annual average rate of 18 percent between 1970 and 1981 (not adjusted for inflation), according to data from the Energy Information Administration. Residential prices increased less (13 percent) than industrial prices (21 percent).

Nevertheless, residential prices today are higher than other prices. Residential users paid an average of $4.29 per thousand cubic feet in 1981; commercial users, $4.02; industrial users, $3.14; and electric utility users, $2.89. (See pp. 4 and 5.)

The average residential price in October 1982 was $6.08 per thousand cubic feet, compared to $2.83 in October 1978 and $0.91 in October 1970 (not adjusted for inflation), according to Bureau of Labor Statistics data for U.S. cities. The average price in selected major cities in October 1982 was as low as $4.94 and as high as $8.20. (See pp. 4 to 6.)

Prices paid by end-users flow back to the three industry segments as gross revenues. According to data from the American Gas Association, producers, pipelines, and distributors all received more revenue per thousand cubic feet in 1981 than in 1970. The producers' share of the total increased from 26 to 53 percent; the pipelines' share decreased from 29 to 25 percent; and the distributors' share decreased from 45 percent to 21 percent. (See pp. 6 and 8.)

The Energy Information Administration projects that the average residential price in the first quarter of 1983 will be about 20 percent higher than the year-earlier price. However, some cities are reportedly expecting increases of 40 percent or more. (See p. 8.)

WHY HAVE NATURAL GAS PRICES INCREASED?

End-user prices for natural gas depend on the diverse factors affecting how gas is priced to pipelines, to distributors, and to end-users. Prices paid by pipelines depend on both the

**Tear Sheet**

quantity of domestic gas in each category under the Natural Gas Policy Act and the price of gas in each category, as well as imported gas. (See pp. 10 to 12.)

Several factors have affected the quantities and prices. One factor has been the regular increase in ceiling prices for various categories under the act. For example, the ceiling for new natural gas increased from $2.08 per million British thermal units (Btu's) in December 1978 to $3.27 in December 1982. (A million Btu's are approximately equal to a thousand cubic feet.) (See pp. 13 and 14.)

Another factor has been the creation of incentive prices for high-cost gas, as provided by the act. According to Energy Information Administration data for major pipelines' projected purchases, the average price of high-cost gas was $6.12 per million Btu's in mid-1981 and $7.24 in mid-1982. (See pp. 14 and 15.)

In addition, certain clauses in producer-pipeline contracts can cause average gas prices to increase. Many contracts obligate the pipeline to purchase a set amount of gas even if the pipeline does not have a ready market (called a "take-or-pay" clause). Such clauses were, in part, a reaction to the existence of Federal price ceilings in the interstate market, but not in the intrastate market, until 1978. (See pp. 16 to 20.)

Other factors include the depletion of old gas reservoirs and imported natural gas. (See pp. 15 and 22 to 23.)

Prices paid by distributors depend on the prices paid by the pipeline suppliers, plus pipeline operating expenses and rates of return. (See pp. 23 to 25.)

Prices paid by end-users depend on the prices paid by their distributors and the way these costs are allocated to residential, industrial, and other classes of users. For example, because of concern about industrial users switching to an alternative fuel, a California distributor has proposed a new rate schedule which would raise the average residential price by about 70 percent and the price to industrial users which can switch to residual fuel oil by about 31 percent. (See p. 25.)

## IS THERE AN IMBALANCE BETWEEN GAS PRODUCTION AND CONSUMPTION?

Reports of a current "excess supply" of natural gas are consistent with major interstate pipeline estimates of supplies which will be available this winter. The duration of this imbalance is uncertain. (See pp. 26 and 27.)

This situation reflects the many factors which determine gas production and consumption. Pipelines eagerly sought new supplies during the 1970s when they could not provide as much gas as their customers desired. There is now an imbalance because pipelines are able to supply more gas than end-users want at current prices. (See pp. 26 to 30.)

Consumption has fallen due to more efficient use of gas, switching to alternative fuels, and economic conditions. Distribution company sales in the first 8 months of 1982 were 4 percent below year-earlier levels, according to the American Gas Association. (See p. 30.)

Some companies are adjusting to the current situation by renegotiating contracts and other means. (See pp. 30 to 32.)

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GAO initiated its analysis in response to requests from Senator Thomas F. Eagleton, Congressman Michael D. Barnes, and Congressman George Miller and 14 others.

As agreed with the requesters' offices, this is a preliminary report. GAO is continuing its analysis of natural gas price increases. GAO did not seek agency comments on this report.

# Contents



## ABBREVIATIONS

| | |
|---|---|
| Bcf | billion cubic feet |
| EIA | Energy Information Administration |
| FERC | Federal Energy Regulatory Commission |
| GAO | General Accounting Office |
| MmBtu | million British thermal units |
| Mcf | thousand cubic feet |
| NGPA | Natural Gas Policy Act of 1978 |
| Tcf | trillion cubic feet |

# CHAPTER 1

## INTRODUCTION

Reports of substantial increases in retail natural gas prices--both recent and expected--have attracted widespread congressional and public attention. These increases may seem particularly puzzling because of concurrent reports that there is a "glut" of natural gas, meaning that more gas could be produced and delivered than is being consumed. Ordinarily, such an imbalance between potential production and consumption would be expected to lead to declining, rather than increasing, prices to consumers.

Natural gas accounts for over 25 percent of the energy consumed in the United States. In 1981, natural gas use totaled 19.3 trillion cubic feet (Tcf), 1/ nearly all of it produced domestically. It is used in about 55 percent of all residential and commercial establishments and provides 40 percent of the energy consumed by industry and agriculture. Overall, industrial use accounts for 41 percent of all gas use; residential, for 24 percent; commercial, for 13 percent; electric generation, for 19 percent; and other uses, for 3 percent.

### STRUCTURE AND REGULATION OF THE NATURAL GAS INDUSTRY

Most natural gas passes through three sectors of the industry before it is consumed. These sectors are regulated variously by units of Federal, State, and local government.

The industry is comprised of three sectors--production, transmission, and distribution--which are physically interconnected by a network of over 1 million miles of pipeline and main throughout the United States. At one end of the network are thousands of large, medium, and small companies which explore for, drill for, and produce gas. Approximately two-thirds of their gas production is sold in interstate commerce and has been subject to Federal price regulation since 1954, now administered by the Federal Energy Regulatory Commission (FERC). 2/ The remaining production is sold in intrastate commerce and has been subject

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1/ Quantities of natural gas are often measured on the basis of volume. Frequently used measures include thousand cubic feet (Mcf), billion cubic feet (Bcf), and trillion cubic feet (Tcf). Alternatively, gas may be measured on the basis of heat content, in terms of British thermal units (Btu's). A million Btu's are approximately equivalent to an Mcf.

2/ Successor to the Federal Power Commission. Established by the Department of Energy Organization Act of 1977, 42 U.S.C. 7107.

to Federal price regulation only since the enactment of the Natural Gas Policy Act of 1978 (15 U.S.C. 3301) (NGPA). 1/

At the other end of the network are almost 1,600 distribution companies, usually local public utilities, serving their own market areas and under the jurisdiction of State or local regulatory bodies. The connecting transmission network includes 129 interstate pipeline companies operating under the jurisdiction of FERC, plus many intrastate pipelines which are generally regulated under State laws.

Producers explore for new reserves of natural gas, develop them to determine their size, and extract the gas from the reserves. Having determined that a reserve is large enough to warrant marketing, the producer will usually negotiate to sell the gas to a pipeline company. Pipeline companies generally purchase this gas--under negotiated contracts--from producers in the field, transport it to market, and sell it either to distribution companies or directly to large industrial and electric utility end-users. 2/

Distributors purchase gas from pipeline companies and resell it to residential, commercial, or industrial customers. Prices paid by a distributor to a pipeline (known as wholesale or "city-gate" prices) depend on (1) field prices which are negotiated by the pipelines within regulatory limits and passed through to the customer and (2) delivery charges for transportation of the gas from the wellhead to the distributor. 3/ Distributors then deliver gas to the final consumer and charge a mark-up over their wholesale purchase price for their delivery services. 4/

Different end-users may pay a distribution company various prices for natural gas, depending on the type of end-use (for example, residential, commercial, industrial, or electric utility)

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1/Production may also be subject to regulation at the State level, with respect to prices and levels of production.

2/Pipeline companies may produce some gas themselves and purchase gas from and resell to other pipelines. Some pipelines also transportation gas for customers which have their own gas supply.

3/Mark-up prices for interstate pipelines are generally determined by the historical average cost of transmission and by the transportation profit margins allowed under FERC regulation.

4/Neither pipelines nor distributors make a profit on the purchase and resale of gas. Mark-ups for both pipelines and distributors include operating and maintenance expenses, depreciation, interest, taxes, and net income. Thus, pipelines' and distributors' profits derive only from their investment in the transportation and delivery systems and not in the gas itself.

and on the type of service (for example, firm or interruptible supply).

In addition to the physical links between the three sectors of the natural gas industry, companies within these sectors can also be connected through common corporate structures. For example, some companies engage in production, transmission, and distribution activities and many of the largest interstate natural gas pipeline companies are involved in natural gas production either directly or through corporate affiliates. Some distribution companies are also involved in the gas producing business, while others are integrated with pipeline companies.

## OBJECTIVES, SCOPE, AND METHODOLOGY

This report was prepared in response to separate, but similar, requests from Senator Thomas F. Eagleton, Congressman Michael D. Barnes, and Congressman George Miller and 14 cosigners. As agreed with the requesters' offices, we concentrated on three questions:

--How much have natural gas prices increased in recent years?
--What factors account for these price increases?
--Is there an excess supply of natural gas and, if so, why?

In this report, we present information in answer to these questions. With respect to the factors which account for price increases, we identified a number of such factors which could contribute, in some measure, to increases in various localities, but we did not attempt to determine which factors are most important in any specific locality. We are continuing our review of natural gas price increases.

In preparing this report, due to time constraints, we relied largely on available data and reports by FERC, the Energy Information Administration, the Bureau of Labor Statistics, and the American Gas Association. We did not independently verify the accuracy of any of these data. Some of the price data on which we relied are adjusted for inflation; others are not adjusted. In each case we identify whether the data were adjusted.

We also relied on our report on "Pipeline Purchases of High-Cost Natural Gas: Extent and Contested Issues" (EMD-82-53, Apr. 6, 1982) and on information gathered in connection with current natural gas reviews. We also discussed the matters covered in this report with representatives of production, pipeline, and distribution companies; Federal and State regulatory agencies; and consumer advocates. Information gained from these sources is cited below in many instances.

Additional details on our methods are included in the subsequent chapters.

This report was prepared in accordance with generally accepted government audit standards.

## CHAPTER 2

## HOW MUCH HAVE PRICES INCREASED?

Although the magnitude of recent and expected price increases has attracted widespread attention, natural gas prices have been rising for many years. At the time of the landmark Supreme Court decision in Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672 (1954)--which formed the basis for Federal regulation of producer prices--the average wellhead price was $.10 per Mcf. In contrast, the price in 1981 was $2.06. 1/

This chapter treats price increases since 1970 from three perspectives: (1) nationwide average prices charged to various classes of end-users, (2) prices charged to residential customers in selected cities, and (3) the breakdown of end-user prices by sector of the natural gas industry.

### PRICES PAID BY CLASSES OF END-USERS

First, we compiled Department of Energy data on prices paid by various classes of end-users between 1970 and 1981. There were differences in 1981 prices to various end-user classes and in the rates of increase between 1970 and 1981. (See table 1.)

Residential and commercial users paid the highest average prices in 1981--$4.29 and $4.02 an Mcf, respectively. Electric utility and industrial users paid the lowest average prices--$2.89 and $3.14 an Mcf, respectively.

Rates of increase also varied. Compounded annual average rates (not adjusted for inflation) increased 11 percent a year between 1970 and 1973 and 22 percent a year between 1974 and 1981. However, in each of the 4-year periods for which we computed average annual increases, residential prices increased by the smallest proportion, followed by commercial prices. Industrial and electric utility prices increased by larger proportions in each 4-year period.

### RESIDENTIAL RATES PAID IN SELECTED CITIES

Next, we compiled Bureau of Labor Statistics data on residential prices between 1970 and 1982 for the Nation and for ten cities. These cities represent various regions of the country but do not necessarily reflect the full range of residential prices. (See table 2.) Furthermore, the data shown reflect average prices per Mcf of gas, not the quantity of gas used nor average customer bills.

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1/Energy Information Administration, 1981 Annual Report to the Congress, Volume 2: Energy Statistics, DOE/EIA-0173(81)/2, May 1982, table 51.

## Table 1

### Prices Paid by End-User Classes, Selected Years, 1970-81, and Rates of Increase

| Year | Residential | Commercial | Industrial | Electric utility | Overall average |
|---|---|---|---|---|---|
| | Average Price | | | | |
| | (price per Mcf) | | | | |
| 1970 | $1.09 | $0.77 | $0.37 | $0.29 | $0.55 |
| 1974 | 1.43 | 1.07 | 0.67 | 0.51 | 0.84 |
| 1978 | 2.56 | 2.23 | 1.70 | 1.48 | 1.85 |
| 1981 | 4.29 | 4.02 | 3.14 | 2.89 | 3.39 |
| **Period** | Compounded Annual Average Rates of Increase | | | | |
| | (percent) | | | | |
| 1970-74 | 7 | 9 | 16 | 15 | 11 |
| 1974-78 | 16 | 20 | 26 | 31 | 22 |
| 1978-81 | 19 | 22 | 23 | 25 | 22 |
| 1970-81 | 13 | 16 | 21 | 23 | 18 |

Source: Energy Information Administration, 1981 Annual Report Report to Congress, Volume 2: Energy Statistics, May 1982 DOE/EIA-0173(81)/2, p. 117, and Natural Gas Annual, 1981, DOE/EIA-0131(81), Sept. 1982, table 16.

These data reveal three trends. First, average prices for cities and prices for the ten cities all increased considerably over this period. Average national prices (not adjusted for inflation) increased by more than six-fold between 1970 and 1982. Prices for all but one of the cities increased between five-fold and seven-fold; San Francisco's prices increased almost nine-fold. Thus, the rates of increase were roughly comparable during the period.

Secondly, there were substantial differences between the lowest and highest prices. In 1970, the prices for San Francisco ($0.71 per Mcf), Atlanta ($0.84), Dallas ($0.86), and Cleveland ($0.87) were considerably lower than the prices for Boston ($1.53), Philadelphia ($1.43), and Seattle ($1.18). In 1982 the prices for Chicago ($4.94), Cleveland ($5.11), and Atlanta ($5.29) continued to be much less than for Boston ($8.20), Philadelphia ($7.54), and Seattle ($6.99).

However, there was some shifting in the cities' relative ranking between 1970 and 1982. For example, San Francisco and Dallas had the lowest prices in 1970 but some of the higher prices in 1982. Boston and Philadelphia had the highest prices in both 1970 and 1982.

The absolute difference between the lowest and highest prices increased from $0.82 per Mcf in 1970 to $3.26 per Mcf in 1982. The lowest price was 46 percent of the highest rate rate in 1970 and 60 percent in 1982.

## COMPONENTS OF END-USER PRICES BY INDUSTRY SECTOR

Finally, we compiled data from the American Gas Association on the components of end-user prices by industry sector for 1970 and 1980. (See table 3.) Prices paid by end-users flow back to the three industry sectors as gross revenues. The data show that revenues to each sector--producers, pipelines, and distributors--increased between 1970 and 1981 (not adjusted for inflation). However, revenues to producers increased by the largest proportion and increased the producers' share of total revenues from 26 percent in 1970 to 53 percent in 1981. Conversely, revenues to pipelines and distributors increased at a slower rate, leading to a decline in the pipelines' share from 29 to 25 percent and a decline in the distributors' share from 45 to 21 percent.

Table 2

Residential Prices in Selected Cities, Selected Years, 1970-1982

| Location | Price per Mcf in October of Year (note d) 1970 | 1974 | 1978 (note c) | 1982 |
|---|---|---|---|---|
| U.S. average | $0.91 | $1.28 | $2.83 | $6.08 |
| Atlanta | 0.84 | 1.24 | 2.71 | 5.29 |
| Boston | 1.53 | 2.23 | 3.32 | 8.20 |
| Chicago | 1.00 | 1.31 | 2.78 | 4.94 |
| Cleveland | 0.87 | 1.21 | 2.18 | 5.11 |
| Dallas | 0.86 | 0.92 | 2.50 | 6.23 |
| Los Angeles | (a) | (a) | b/ 1.85 | 5.71 |
| Philadelphia | 1.43 | 1.88 | 3.88 | 7.54 |
| St. Louis | 0.95 | 1.35 | 2.34 | 6.15 |
| San Francisco | 0.71 | 1.12 | 2.14 | 6.26 |
| Seattle | 1.18 | 1.62 | 3.74 | 6.99 |

Source: Bureau of Labor Statistics, Retail Prices and Indexes of Fuels and Electricity, Nov. 1970, table 6; Nov. 1974, table 7; and June 1978, table 7; and Energy and Food--October 1982, Nov. 22, 1982, table 1; and unpublished data.

a/Not available.

b/Earliest available data for Los Angeles are for November 1978.

c/Consumer prices were not collected from July through October 1978, due to revision of the BLS Consumer Price Index. Data shown were interpolated from June and November 1978 figures.

d/Based on prices for 100 therms of gas in each city, converted to cubic feet at a rate of 1,021 Btu's per cubic foot.

Table 3

Components of End-User Prices, by Sector, for 1970 and 1981

| Sector | 1970 Price per Mcf | 1970 Percent of total | 1981 Price per Mcf | 1981 Percent of total |
|---|---|---|---|---|
| Producer | $0.17 | 26 | $2.00 | 53 |
| Pipeline | 0.19 | 29 | 0.94 | 25 |
| Distributor | 0.29 | 45 | 0.80 | 21 |
| Total | $0.65 | 100 | $3.74 | 100 |

Source: American Gas Association, Gas Facts, 1980, p. 122, and unpublished data.

## EXPECTED PRICE INCREASES TO RESIDENTIAL USERS

Expected price increases in cities around the country have received widespread media coverage. Such estimates are usually based on pipeline filings at FERC and on other factors; actual increases may ultimately be different.

The Energy Information Administration projects that the average price for residential users will be $5.97 per Mcf in the first quarter of 1983, about 20 percent higher than the year-earlier price of $4.99. 1/ Projected increases in individual cities, however, are expected to vary considerably. Distribution company representatives told us that some cities are expecting increases of 40 percent or more.

## CONCLUSIONS

Prices paid by natural gas end-users vary considerably. Residential and commercial users (both over $4.00 per Mcf) paid higher prices than industrial ($3.14) and electric utility ($2.89) users in 1981. However, industrial and electric utility prices increased faster between 1970 and 1981.

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1/Energy Information Administration, Short-Term Energy Outlook, DOE/EIA-0202 (82/3Q), Aug. 1982, p. 4. This estimate represents the middle of three cases projected by EIA, based on different assumptions of future world oil prices. Prices are shown in current dollars.

Prices paid by residential customers increased overall between 1970 and 1982, but at somewhat different rates. Current prices vary considerably from city to city--from less than $5.00 per Mcf to more than $8.00.

Natural gas producers' proportion of revenues from end-user sales increased from 1970 to 1981 (from 26 percent to 53 percent). The pipelines' share declined (from 29 percent to 25 percent), and the distributors' share declined (from 45 percent to 21 percent).

The Energy Information Administration projects that average residential rates will increase 20 percent from the first quarter of 1982 to the first quarter of 1983. Increases in individual cities will reportedly vary considerably.

# CHAPTER 3

## WHY HAVE PRICES INCREASED?

Although natural gas end-user price increases are not a new phenomenon, the reported magnitude of expected increases in some cities is unusual. This chapter examines various reasons which could account for some portion of the increases. It addresses the factors which affect: (a) prices charged to pipelines, (b) prices charged to distributors, and (c) prices charged to end-users.

In this preliminary analysis, we did not attempt to determine the contribution of each factor nor to determine which factors are most important in various localities.

### PRICES CHARGED TO PIPELINES

Pipeline purchases from producers are governed by the Natural Gas Policy Act of 1978. The act established eight major price categories, covered by Sections 102 through 109, 1/ and additional sub-categories depending on when a well is drilled, how deep the well is, when and where the gas was contracted for, and other criteria. Allowable prices for these categories vary widely. This section discusses factors which affect prices charged to pipelines, including prices and quantities of domestic purchases from producers and of purchases of imported gas.

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1/The NGPA's definitions of the major price categories are complicated. The following definitions are general descriptions only. Section 102 covers gas from new onshore reservoirs, new wells at a minimum distance or depth from an existing well, and certain Outer Continental Shelf reservoirs. Section 103 covers gas from new wells less than a minimum distance or depth from an existing well. Section 104 covers gas from wells dedicated to interstate commerce as of the date of enactment of NGPA. Section 105 covers gas under existing intrastate contracts as of the date of enactment. Section 106 covers gas under "rollover contracts," both inter- and intrastate; such a contract is entered into on or after the date of enactment for gas that was subject to an earlier contract that expired at the end of a fixed term. Section 107 covers high-cost natural gas, from wells at a depth of 15,000 or more feet and three other sources specified in the act or from other sources determined by FERC to present extraordinary costs or risks. Section 108 covers gas from "stripper" wells producing less than 60 Mcf per day under normal conditions or more than 60 Mcf per day due to enhanced recovery techniques. Section 109 covers gas not covered by any other price provision.

Domestic Purchases

Pipelines purchase gas from various NGPA categories and at various prices. The pipelines' average cost of gas in a time period depends on both prices and quantities. Both the quantity of gas in each category and the average price paid vary, as shown in table 4 for major pipelines' projected purchases for 2 successive years. (These data were compiled by the Energy Information Administration from pipeline filings at FERC, based on pipelines' projections of gas purchases in future periods.)

The total quantity increased by 2 percent. But the quantity of old (sections 104 and 106) gas contracted for in 1972 or earlier declined 15 percent, while the quantity of section 102 gas increased 18 percent and the quantity of high-cost (section 107) gas increased 70 percent.

The average price increased 17 percent (adjusted for inflation). The average price of old gas contracted for in 1973 and later declined 1 percent, old gas contracted for in 1972 or earlier increased 2 percent, and high-cost gas increased 18 percent.

The increase in the average price, from $2.01 to $2.35 (adjusted for inflation), reflects both changes in proportionate quantities and changes in prices. To provide some perspective on the relative importance of prices and proportions, we compared the actual prices and quantities for 1981 with two alternatives. First, we calculated the average price of buying the 1981 volumes at the 1982 prices, to illustrate the importance of changes in price; the average price went from $2.01 to $2.10. Secondly, we calculated the average price of buying the 1982 volumes at the 1981 prices, to illustrate the importance of changes in proportions; the average price went from $2.01 to $2.22.

The overall increase of $0.34 per Mcf may be compared with the 1981 quantities/1982 prices increase of $0.09 and the 1982 quantities/1981 prices increase of $0.21. The changes in proportionate quantities appear to account for about twice as much of the overall change as the price changes. Even after the 7-percent inflation rate between the two periods is considered, the changes in proportionate quantities appear to account for at least half the overall change. (These results relate only to the two periods cited above and would not necessarily hold true for other periods.)

The overall changes in quantities and prices reflect many factors, including increases in maximum lawful prices under the Natural Gas Policy Act, the establishment of incentive prices under section 107, the natural decline of gas reservoirs, recategorization of gas from one sub-category to another, the operation of certain clauses in producer-pipeline contracts, and the effectiveness of Federal regulation.

## Table 4

### Projected Natural Gas Wellhead Purchase Volumes and Prices For Major Interstate Pipeline Companies, 1981 and 1982

| Category of gas | Mid-1981 (note a) Volume in Bcf (note b) | Mid-1981 (note a) Price per Mcf (note c) | Mid-1982 (note a) Volume in Bcf (note b) | Mid-1982 (note a) Price per Mcf (note c) |
|---|---|---|---|---|
| Old gas (note d) (Sections 104 and 106) | | | | |
| Contract date 1972 or earlier | 3,665 | $0.89 | 3,129 | $0.91 |
| Contract date 1973 or later | 2,683 | 1.73 | 2,674 | 1.71 |
| New gas | | | | |
| Section 102 | 1,992 | 3.04 | 2,342 | 3.20 |
| Section 103 | 1,060 | 2.79 | 1,184 | 2.86 |
| Sections 108 and 109 | 296 | 3.04 | 300 | 3.21 |
| High-cost gas (Section 107) | 390 | 6.12 | 664 | 7.24 |
| Other | 85 | 2.60 | 60 | 2.87 |
| Total (note e) | 10,170 | $2.01 | 10,352 | $2.35 |

a/For definition of periods covered, see source report.

b/Volumes are given at an annual rate.

c/Prices are given in constant January 1982 dollars.

d/Contract date was unknown for 226 Bcf in 1981 and 139 Bcf in 1982. To facilitate comparisons, these quantities were added--on a pro rata basis--to the quantities whose contract date was known. Prices for gas with a known contract date only were used.

e/Detail may not add to total due to rounding.

Source: EIA, An Analysis of Post-NGPA Interstate Pipeline Wellhead Purchases, DOE/EIA-0357, Sept. 1982, p. vi.

### Increased ceiling prices

The Natural Gas Policy Act of 1978 provided for regular increases in the maximum lawful price for most gas. In many categories the increase was tied to the rate of inflation. But for section 102 (new natural gas) it was allowed to increase at an annual rate of 3.5 percent faster than inflation through April 20, 1981, and at an annual rate of 4.0 percent faster than inflation through December 31, 1984; on that date section 102 and certain other gas will be freed of Federal price controls.

Based on these factors, ceiling prices increased between December 1978 and December 1982 by 38 percent for most categories and by 58 percent for section 102. (See table 5.) These ceiling

Table 5

Maximum Lawful Prices for Selected Categories of Natural Gas, December 1978 and 1982

| Section | Category of gas | Maximum lawful price per million Btu's December 1978 | Maximum lawful price per million Btu's December 1982 |
|---|---|---|---|
| 102 | New natural gas, certain Outer Continental Shelf gas | $2.08 | $ 3.27 |
| 103 | New onshore production wells | 1.97 | 2.71 |
| 104 and 106(a) | Existing interstate and intrastate contracts | | |
| | Post-1974 gas | 1.63 | 2.24 |
| | 1973-74 biennium gas (large producers) | 1.06 | 1.45 |
| | Interstate rollover gas | 0.60 | 0.83 |
| | Minimum rate gas (note a) | 0.20 | 0.28 |
| 107(c)(5) | Gas produced from tight formations | (b) | 5.42 |
| 108 | Stripper gas | 2.22 | 3.51 |

a/Price expressed in terms of Mcf.

b/FERC, by Order 99, Aug. 15, 1980, set the maximum lawful price for gas produced from tight formations at the lesser of the negotiated contract price or 200 percent of the Section 103 maximum price. The maximum price generally applies on or after July 16, 1979.

Source: FERC.

price increases promptly result in increased prices to pipelines, in many cases, because many producer-pipeline contracts obligate the purchaser to pay the "highest regulated rate."

Incentive prices for high-cost gas

Among the major pricing categories established by the 1978 act is section 107, High-Cost Gas. The act defined high-cost gas to include

--gas produced from a well deeper than 15,000 feet (if drilling began on/or after Feb. 19, 1977);

--gas produced from geopressured brine, released naturally from coal seams, and produced from Devonian shale; and

--other gas "produced under such other conditions as the Commission determines to present extraordinary risks or costs."

The act provides that the price for deep gas be limited to the section 102 ceiling price ($3.27 per MmBtu in Dec. 1982), and authorized the Commission to prescribe higher prices for any high-cost gas "to the extent that such special price is necessary to provide reasonable incentives for the production of such high-cost natural gas."

The Commission issued a regulation in November 1979, pursuant to the NGPA, which removed Federal price ceilings for deep gas and gas from the other three sources cited in the act. It issued another regulation in August 1980 which established an incentive price for gas produced from tight formations (geological structures which allow gas to seep out slowly, under normal conditions). It set a maximum price for such gas at twice the ceiling price for section 103 gas (equal to 2 x $2.71 = $5.42 in December 1982). 1/

According to EIA's analysis of pipelines' projected purchases by volume, high-cost gas constituted 4 percent in mid-1981 and 6 percent in mid-1982. For five pipelines, however, high-cost gas constituted 10 to 15 percent of all projected purchases. Pipelines expected to pay an average of $6.12 per MmBtu for all high-cost gas in mid-1981 and $7.24 in mid-1982 (both in January 1982 dollars). These prices are considerably higher than the average prices for all wellhead purchases ($2.01 in mid-1981 and $2.35 in

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1/See 44 Fed. Reg. 61,950 (1979) and 44 Fed. Reg. 56,034 (1980).

.a-1982). 1/ Therefore, high-cost gas constitutes a relatively ırge proportion of total gas costs for some pipelines.

In an earlier study, we found that high cost gas constituted :om none to 40 percent of all projected wellhead purchase costs ɔr 20 pipelines. This gas accounted for 5 percent or less for ix companies, 6 to 25 percent for eight companies, and 26 percent c more for six companies. 2/

Depletion of old fields

A reservoir contains a given quantity of natural gas. The mount of gas that can be produced economically from a reservoir enerally declines each year. The productive life of a reservoir aries, depending on geology and other factors: an individual well ay produce economically for a few years or for 20 years or more. hus, to maintain a stable gas supply, the continuing depletion of xisting reservoirs is balanced by the addition of new reservoirs.

This turnover can lead to higher prices because production :rom the older reservoirs generally commands a lower price than ›roduction from the newer reservoirs. As previously noted in :able 4 (page 12), expected prices in mid-1982 were $0.91 per Icf for gas contracted for in 1972 or earlier, $1.71 for gas :ontracted for between 1973 and 1977, $3.20 for new gas (section .02), and $7.24 for high-cost gas.

Recategorization of gas

Because of the numerous pricing categories under the Natural ;as Policy Act, and the differences in maximum lawful prices, a ɔroducer has an incentive to try to get each well qualified to :eceive the highest possible price. The act--in section 101(b) (5)--provides that gas qualifying for more than one price category nay be priced according to the highest applicable price category.

Moreover, the act and FERC regulations provide that gas produced from a well may qualify for an increased price under specified circumstances. For example, application of production enhancement techniques to a well may permit a producer to charge a higher price than would otherwise be permitted. As of August 1, 1982, according to FERC data, FERC had been notified that enhanced recovery techniques has been applied to 432 wells, thus

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1/Energy Information Administration, An Analysis of Post-NGPA Interstate Pipeline Wellhead Purchases, DOE/EIA-0357, Sept. 1982, pp. 6 and 28.

2/"Pipeline Purchases of High-Cost Natural Gas: Extent and Contested Issues," EMD-82-53, Apr. 6, 1982, pp. 10 and 11.

permitting gas from these wells to receive a higher price than they would otherwise qualify for.

There have been conflicting reports about the extent to which gas has been recategorized from a lower to a higher price. This phenomenon has been called "category creep." Based on these reports, it is not clear to what extent recategorization has increased prices.

A June 1981 study of wellhead price increases concluded that an "unexpectedly high" price for gas contracted for before enactment of NGPA appeared to be due, in part, "to a change in the mix of gas within the price subcategories * * *. The lower priced ones disappear more quickly than the higher priced ones, and, in fact, there may be some shifting of volumes into the higher priced groups" (emphasis added.) 1/

In its November 1982 report, EIA stated: "To the extent that such an effect can be estimated, the data examined and presented in this report provide no evidence that there has been any substantial degree of gas reclassification in the period studied." 2/ However, it should be noted that EIA's definition of "category creep" is more limited than that used elsewhere. EIA notes that it has been "hypothesized that some natural gas producers have been able to reclassify old gas volumes as new gas by drilling new development wells in old fields--often referred to as 'category creep.'" This definition does not include recategorization of flowing gas.

Clauses in producer-pipeline contracts

Contracts for the purchase of gas at the wellhead define the long-term relationship between the producers of gas and the purchasers--primarily pipeline companies--and in large part determine the cost of gas to distributors and end-users. The producer-pipeline contract specifies the terms and conditions of the gas sale. Among other things, the contract generally stipulates (1) the duration of the purchase agreement; (2) the price, including initial rate and price escalation provisions, the treatment of taxes, royalty payments, and deregulation clauses, if any; (3) the delivery rate--daily, monthly, and annual purchase (or "take") obligations and any makeup provisions; (4) the quantity of gas or acreage committed; (5) the gathering, processing, and delivery of the gas; and (6) the quality and measurement of the gas.

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1/Edmond R. DuPont & Associates, Preliminary Assessment of Gas Rate Changes under NGPA, June 26, 1981, pp. 7 and 9. This study was prepared under contract for the American Gas Association.

2/EIA, An Analysis of Post-NGPA Interstate Pipeline Wellhead Purchase DOE/EIA-0357, Sept. 1982, p. x.

Contracts reflect the relative bargaining leverage of producers and pipeline companies at a given time. This bargaining relationship has shifted over the years to adjust to changes in the overall supply and demand for gas both nationally and in specific regional markets, the regulatory environment, and internal producer and pipeline corporate policies. Because pipelines may have more than one contract with a producer, a specific producer-pipeline contractual relationship can be viewed in the context of a web of existing and prospective contracts.

Natural gas contracts--like other contracts--represent a compromise between the conflicting bargaining positions of the seller (the producer) and the buyer (the pipeline). The producer has certain objectives in negotiating a contract, as does the pipeline company. The producer tries to obtain, among other things, the highest possible contract price and large daily pipeline gas purchase obligations (a high contract price provides little revenue if the pipeline purchases only a small daily volume). In contrast, the pipeline desires large gas reserves under long-term contracts at a lower price and minimum daily purchase obligations. This allows the pipeline to provide its customers a secure, stable supply of gas.

Contracting practices appear to respond to changes in the overall market for gas. For example, in the early years of the industry when gas supplies were abundant, the demand for gas was limited because there was not yet a well developed pipeline system to bring the gas from the field to urban markets. As a result, contracts generally reflected the strong bargaining position of the pipeline. They were often long-term contracts, with low prices and low daily purchase obligations.

However, in later years, especially in the early 1970s, with the increased demand for gas and a limited supply of new reserves, the relative bargaining strength shifted to producers. Producers were able to incorporate into their contracts higher purchase obligations, prices at maximum allowed levels, and more frequent price redeterminations. More recently the pendulum has swung again, and pipelines have now been able to incorporate lower purchase obligations, provisions allowing purchasers to lower contract prices, and more favorable price escalation terms into contracts.

Other factors that affect the bargaining relationship are (1) the number of pipelines competing for gas in a specific producing area, (2) the size of the reserves, and (3) differing corporate perceptions of the future gas market and regulatory environment.

The universe of contracts is quite large. An estimated 20,000 mostly pre-NGPA interstate contracts are on file at FERC. 1/ Although most producers are no longer required to file contracts, FERC's Chairman estimated a year ago that between 9,000 and 10,000 contracts had been executed since the enactment of NGPA, covering new gas sales. 2/ At any time, a pipeline may have hundreds or thousands of contracts with gas producers. Further complicating this situation is the fact that a pipeline will often have several different gas contracts with an individual producer.

As noted above, many contracts obligate the pipeline to pay the "highest regulated rate." Two other types of clauses which have received considerable attention recently are "take-or-pay" clauses and "market-out" clauses. The former require the purchaser to pay the producer an amount based on a stated proportion of a well's potential or actual output--even if the purchaser chooses not to accept the entire quantity; however, such clauses often allow the purchaser to accept the paid-for gas in subsequent years. The latter allow the purchaser to offer the producer a lower price, if the existing price has made the gas unmarketable; however, such clauses often allow the producer to try to find another purchaser.

During the early and mid-1970s interstate pipelines could not always supply as much gas as their customers wanted. As will be explained more fully in the following chapter, they were subject to Federal price ceilings, which kept their prices lower than the levels which could be paid by intrastate pipelines. One way of redressing this imbalance was for the interstate pipelines to bargain on the basis of "non-price" contract terms, for example, take-or-pay clauses. 3/

"Take" obligations became increasingly strict during the 1970's. In some cases the purchasers were obligated to pay for 80

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1/In general, small producer contracts, intrastate contracts, and contracts for onshore gas executed after the enactment of the NGPA are not on file at FERC. Some post-NGPA contracts for new offshore gas are on file at FERC. See Decision Analysis Corporation, Analysis of Natural Gas Producer/Interstate Pipeline Contracts, July 1, 1981, p. 2.

2/Based on well determinations filed with FERC since Dec. 1, 1978. This estimate appears in a Nov. 20, 1981, letter to Philip R. Sharp, Chairman, Subcommittee on Fossil and Synthetic Fuels, House Committee on Energy and Commerce, from C.M. Butler III, Chairman, Federal Energy Regulatory Commission.

3/"Non-price" is technically a misnomer. Such clauses do not relate to current prices, but they do relate to future prices, current and future quantities, and other conditions.

or 90 percent of the output of a well. Only in the last couple of years have "take" obligations become less strict or tempered by the presence of "market-out" clauses. 1/ However, the high "take" obligations in contracts signed throughout the last decade or more remain in effect unless renegotiated.

The effects of high "take" obligations have received considerable attention. Examples of the operation of such clauses have been noted in two regions.

--In the Hugoton field (in southwest Kansas, Oklahoma, and Texas), several pipelines have reduced their purchases of gas--much of which sells for as little as $0.50 per Mcf and are instead purchasing domestic and imported gas at $5.00 or more per Mcf, according to Kansas State and pipeline company representatives.

--In Appalachia, Columbia Pipeline has stopped accepting gas from 21,000 small wells, whose prices are as low as $0.45 per Mcf, while continuing to buy gas from southwestern producers for up to $8.30 per Mcf, according to a company official. He stated that the wells were "shut-in" for between 90 and 150 days and that the company also shut-in its own wells in Appalachia during the period.

There are several possible reasons why pipelines--when they expect to need less gas than they could purchase under existing contracts--may choose to forego relatively inexpensive gas and, instead, purchase relatively expensive gas. First, as a general rule, the more expensive gas is likely to be covered by contracts with higher "take" obligations. This occurs because take-or-pay clauses became more prevalent during the last decade or so, at the same time that maximum lawful prices were being increased.

Second, pipelines may prefer to buy gas from their own affiliated producers or production subsidiaries, rather than from unaffiliated producers. This could cause pipelines to buy relatively expensive gas because pipeline involvement in gas production has increased in recent years, at the same time that maximum lawful prices were being increased. Third, pipelines may be willing to pay higher prices to develop or retain the good will of producers on whom they may depend in various producing regions.

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1/Energy Information Administration, Natural Gas Pipeline/Producer Contracts: A Preliminary Analysis, Dec. 1981, DOE/EIA-0312, and Natural Gas Producer/Pipeline Contracts and Their Potential Impacts on the Natural Gas Market: An Analysis of the Natural Gas Policy Act and Several Alternatives, Part 2, June 1982, DOE/EIA-0300.

Finally, pipelines' purchases may be influenced by the nature of Federal regulation. Pipeline tariff rates are established at least every 3 years based on a cost-of-service review. One aspect of such a review is a determination of the cost of gas purchased by the pipeline for resale. Recognizing that purchased gas costs would likely change more frequently than every 3 years, pipelines were allowed, starting in 1972, to adjust their rates in the intervening period. A pipeline's request to change its base tariff rates to reflect purchased gas costs is known as a purchased gas adjustment filing. Most interstate pipelines file an application every 6 months, while the remainder file annually. These filings are subject to FERC review and approval.

In the situation where a pipeline is contractually obligated to pay for more gas than it needs, if the pipeline pays for and receives gas from a producer, it can generally recover its costs through a purchased-gas adjustment filing every 6 months according to FERC officials. However, if a pipeline pays for but does not receive the gas, it cannot promptly recover such "pre-payments". Only after it receives the gas can it recover these "pre-payments" through a purchased-gas adjustment filing.

In the meantime, the pipeline can add the "pre-payments" to a specified account in its rate base and earn a rate of return on them. Therefore, to maintain cash flow, a pipeline may prefer to buy more expensive gas and recover its costs semi-annually, but incur any "pre-payments" on less expensive gas and recover these costs later. To the extent that "take-or-pay" and other contract clauses influence a pipeline to buy more expensive gas and forego less expensive gas, such clauses will contribute to an increase in the pipeline's average gas costs.

## Federal regulation

Violation of Federal or State laws relating to prices received by producers or prices paid by pipelines could also result in price increases. NGPA specifies maximum lawful prices to be received by producers. It also specifies certain standards to govern pipeline purchases, including purchases from entities affiliated with a pipeline. FERC is responsible for compliance and enforcement with both types of regulation. If there were violations of either type of regulation, end-user prices would presumably be increased.

According to FERC data, it was found that too high a price had been charged at about 1,300 wells as of October 31, 1982, and about $39 million had been refunded since NGPA's enactment. (This amount may be compared to total producer revenues in 1981 of about $42 billion--20.4 Tcf of marketed production x $2.06 per Mcf average wellhead price.)

In addition, FERC regulates prices paid by pipelines. Section 601(b) of NGPA generally provides that producer-pipeline wellhead transactions are considered to be just and reasonable if the price does not exceed the maximum price authorized by Title I or if there is no ceiling for that category. Under section 601(c) interstate pipelines may pass through costs of natural gas purchases if the price, deemed "just and reasonable" under section 601(b), is not excessive due to "fraud, abuse, or similar grounds." The meaning of this "fraud standard" is highly controversial and affects pipelines' authority to pass through hundreds of millions or even billions of dollars.

As we reported in April 1982, six pipeline company purchased-gas adjustment filings were protested in 1981 because of issues relating to the purchase of deregulated gas. 1/ Protesters contended, in part, that (1) prices paid for deregulated gas were too high in relation to prices for competing fuels; (2) prices paid to pipeline affiliates were too high; and (3) pipelines bought more deregulated gas than they needed.

The pipeline companies involved in the six cases responded, in part, that (1) the deregulated gas was purchased to obtain adequate reserves for their customers; (2) the protesters did not show that the purchases were unwarranted; and (3) the protesters were attempting to reimpose price ceilings on deregulated gas.

In February 1982, FERC issued a policy statement on its interpretation of the NGPA's provisions relating to pipeline pass-through of purchase gas costs as guidance for the disposition of proceedings where the fraud standard is an issue. 2/ The Commission stated that the general policy statement does not have the force of law, but "is an articulation of the Commission's tentative intention which will be followed unless circumstances demonstrate the policy to be inappropriate."

FERC said that it intended to limit the fraud standard to consideration of whether the price paid by an interstate pipeline was excessive due to misrepresentation, including a positive statement of fact or an omission of a material fact. It stated that the fraud standard is not a market-ordering device and that there is nothing within the 1978 act nor its legislative history enabling it to disallow pass-through of prices due to imprudence. FERC concluded that the fraud standard does not include imprudent business judgment about how much a pipeline should pay for gas. More recently, however, FERC indicated that it may consider questions of prudence of pipeline purchases. 3/

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1/"Pipeline Purchases of High-Cost Natural Gas: Extent and Contested Issues," EMD-82-53, Apr. 6, 1982.

2/47 Fed. Reg. 6,253 (1982).

3/In connection with a purchased-gas adjustment filing of Tennessee Gas Pipeline (TA82-2-9), the Commission stated that it may consider questions of prudence as part of a pipeline's cost-of-service review.

## Other Factors

FERC has been criticized for its part in several decisions which have allowed gas price increases to pipelines. 1/

--In March 1979 FERC reversed its month-earlier proposal and allowed the 1978 act to trigger "area rate clauses." These clauses may allow producers to charge as much as other producers in an area. (44 Fed. Reg. 16,895 (1979).)

--In July 1980, FERC permitted producers to obtain a higher wellhead price retroactive to December 1, 1978, based on a change in measuring the heat content of gas. (45 Fed. Reg. 49,077 (1980).)

--In August 1980, FERC decided to allow pipelines to collect NGPA rates for gas produced by pipeline affiliates. (45 Fed. Reg. 53,091 (1980).)

## Imported Gas Purchases

Natural gas has been imported, primarily from Canada, for many years. In the last few years, imports have constituted about 5 percent of total national supplies, but much higher proportions for some pipelines and distributors.

Quantities of imported gas--from Algeria, Canada, and Mexico--changed little between 1978 and 1981. (See table 6.) However, prices increased significantly between 1978 and 1981.

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1/A critical assessment of FERC's role in these and other actions is contained in "Comments of the Citizen/Labor Energy Coalition Regarding Notice of Inquiry," Docket No. RM82-26-000, Impact of the NGPA on Current and Projected Natural Gas Markets, Aug. 26, 1982, pp. 5 and 6 and App. A.

Table 6

Natural Gas Imports, 1978-81

| Year | Source | Quantity (in Tcf) | Price per Mcf |
|---|---|---|---|
| 1978 | Canada | 0.88 | $ 2.19 |
| | Mexico | - | - |
| | Algeria | 0.08 | 1.53 |
| 1979 | Canada | 1.00 | 2.61 |
| | Mexico | - | - |
| | Algeria | 0.25 | 2.03 |
| 1980 | Canada | 0.80 | 4.32 |
| | Mexico | 0.10 | 4.41 |
| | Algeria | 0.09 | 3.77 |
| 1981 | Canada | 0.76 | 4.83 |
| | Mexico | 0.11 | 5.01 |
| | Algeria | 0.04 | 5.54 |

Source: Energy Information Administration, U.S. Imports and Exports of Natural Gas, 1981, DOE/EIA-0188(81), June 1982.

The price of imports was above the average well-head price of domestic gas during these years. Domestic gas, on the average, cost $0.90 per Mcf in 1978, $1.18 in 1979, $1.60 in 1980, and $2.06 in 1981. 1/

A notable development relating to gas imports is the proposal by Panhandle Eastern Pipeline to import liquefied natural gas from Algeria. This gas would cost more than $7.00 per MmBtu when landed in Louisiana and more than $8.50 per MmBtu when delivered to distribution companies in the midwest, according to the representative of one such company.

Based in part on Panhandle's stated plans to import this gas, some distributors have projected substantial price increases. However, the imports are being contested and it is not clear how much of the gas will be sold to distributors and at what price.

## PRICES CHARGED TO DISTRIBUTORS

Distributors generally buy their supplies from the one, or at most the few, pipelines that serve their area. Terms of trade

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1/Energy Information Administration, Annual Report to Congress, Vol. 2: Energy Statistics, May 1982, DOE/EIA-0173(81)/2, table 53.

between pipelines and distributors are not established by direct negotiation between the parties. Instead, interstate pipeline sales to distributors are governed by tariffs approved by FERC; distributors can be involved in FERC's process for setting such tariffs.

These tariffs establish such conditions as prices, quantities to be supplied, and minimum purchase (or "minimum bill") obligations. The price charged is typically the average price of gas paid by the pipeline plus an amount to cover the pipelines' operating expenses and provide a return on the pipelines' capital investments.

One possible source of increases in prices charged to distributors is the triggering of "minimum bill" provisions. However, representatives of two trade associations representing distributors told us that they were aware of few significant examples of "minimum bill" provisions being triggered.

Other provisions of pipeline distributor tariffs may also restrict the distributors' flexibility in gas supply. For example, an Illinois distributor, Central Illinois Light Company, has complained to FERC about its rate classification with Panhandle Eastern Pipeline. According to a company representative, the distributor stated that its current rate schedule prevents it from buying gas from another pipeline at a lower price and, thus, inhibits the distributor from trying to reduce its gas supply costs.

A second possible source is an increase in pipeline operating expenses and rates of return. According to American Gas Association statistics, the average pipeline share of revenue per Mcf increased at an average rate of 15 percent between 1970 and 1978 and 17 percent between 1978 and 1981. In contrast, during these same two periods the average distributor share of revenue per Mcf increased at average rates of 12 percent and 3 percent, respectively. (See table 3, on p. 8.)

Finally, pipelines' sales to distributors may be affected by declines in pipelines' direct sales to industrial and electric utility customers. According to an investment firm's analysis, such sales are important to pipelines for two reasons.

--Industrial consumption tends to be less weather-sensitive than residential consumption. This "demand constancy not only allows the pipeline to operate more efficiently, but also to amortize its operating costs over a larger number of units," spread fairly evenly over the year. "Loss of industrial load disrupts this balance, increases a system's weather sensitivity, and forces operating cost recovery onto fewer units," resulting in an increase in the delivered price of gas.

--Moreover, "large volume sales for industrial consumption or for electric generation include the highest margin transactions among pipeline deliveries * * *." 1/

The decline in industrial and electric utility sales between 1981 and 1982 may, therefore, be working to increase prices on pipelines' sales to distributors.

PRICES CHARGED TO END-USERS

Although prices charged by producers and interstate pipelines are regulated by the Federal Government, rates charged by distributors are usually subject to State or local regulation. Accordingly, developments in this area are very diverse.

A significant development in at least some areas of the country is the loss of industrial sales, not only losses already experienced but also anticipated losses, which are due largely to switching from gas to another fuel--often residual (or No. 6) fuel oil. The loss of industrial customers can affect distributors in some of the same ways that it affects pipelines--by reducing the number of units which contribute to paying operating costs and reducing the company's operating efficiency by increasing the company's weather sensitivity.

In an attempt to discourage industrial users from switching to an alternative fuel, distribution companies and State regulators in some areas of the country are considering or have approved rate schedules that would raise rates to residential users by a larger proportion than rates to industrial users. For example, consistent with the State of California's statutes and guidance from the California Public Utility Commission, the distributor serving Los Angeles has had higher average rates for industrial users than for residential users. But, because of concern about users switching from gas, the company has proposed a new rate structure which would place more of the cost burden on residential customers. Rates for industrial users which could switch to residual fuel oil would increase from $4.16 per MmBtu in January 1982 to $5.47 in January 1983, a 31-percent increase, while residential users face an average rate increase of about 70 percent, according to company officials. 2/

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1/R. Gamble Baldwin and Robert L. Christensen, Jr., Large Volume Sales of Natural Gas: Their Importance and Vulnerability, First Boston Corporation, Special Report GT 1398.82, Aug. 1982, pp. 10 and 11.

2/Residential rates in January 1982 were $2.83, $3.81, and $5.67 per MmBtu, with higher rates for those who consume more. As of November 30, the California Commission has not acted on the company's proposal.

## CONCLUSIONS

Numerous factors have contributed to natural gas price increases before and since enactment of NGPA. End-user rates for natural gas depend on the diverse factors affecting how gas is priced to pipelines, to distributors, and to end-users.

Prices paid by pipelines are based on purchases of both domestic and imported gas. Prices for domestic gas depend on both the quantity of gas in each category and the price for each category; these quantities and prices, in turn, are influenced by many factors, including (1) the NGPA's escalation provisions, (2) incentive prices for high-cost gas, (3) depletion of old fields, (4) recategorization of gas, (5) "take-or-pay" and other clauses in producer-pipeline contracts, (6) Federal regulations, and (7) other factors.

Prices paid by distributors depend, in part, on increases in pipeline operating expenses and rates of return and the loss of direct sales to industrial and electric utility customers. Prices paid by end-users depend, in part, on the allocation of cost increases between residential, industrial, and other users.

# CHAPTER 4

## CURRENT MARKET CONDITIONS

Reports of increases in retail natural gas prices may seem incompatible with other reports of an "excess supply" of natural gas. This chapter first examines whether such an "excess supply" exists, then discusses reasons which may account for it, and finally considers evidence that the industry is adjusting to current market conditions.

### IS THERE AN IMBALANCE BETWEEN GAS PRODUCTION AND CONSUMPTION?

The expected balance between natural gas production and consumption in any time period depends on current production, net withdrawals from or additions to storage, and current consumption. Even if these amounts are known, or can reasonably be predicted, for a given time period on a national basis, conditions facing an end-user will depend largely on the situation of one or more pipelines serving a specific location.

FERC staff have collected information from major interstate pipelines about their expected supply availability for the forthcoming winter heating season (November through March) and actual supplies used during the previous season. (Estimates are prepared for a normal winter and for somewhat colder winters.) These data provide one measure of the balance between production and use.

Data submitted by the companies show that company estimates of available supplies for a normal winter were somewhat higher than actual supplies used in the winter of 1980-81 and very close to equal in the winter of 1981-82. (See table 7.)

Estimates of available interstate supplies for the current heating season total 6,653 Bcf. This level is higher than both estimated supplies available (6,053 Bcf) and actual supplies used (6,037 Bcf) for last winter. Moreover, based on American Gas Association data for gas utility sales during the first 8 months of 1982, it appears likely that this winter's sales will be below last winter's sales. Using the 4.3 percent decline for the first 8 months as a basis of comparison, it is plausible to expect that this winter's sales may total about 5,777 Bcf.

Thus, estimated interstate supplies available for a "normal" winter in 1982-83 are about 10 percent higher than actual supplies used in 1981-82, and about 15 percent higher than a plausible projection of actual supplies to be used in 1982-83. Such differences could be characterized as an "excess supply."

### HOW DID THE CURRENT SITUATION DEVELOP?

The current "excess supply" of gas connotes an imbalance between production and consumption. This imbalance may be traced to the various factors which affect both production and consumption.

Table 7

Major Pipeline Companies Estimated and Actual Supplies for Winters of 1980-81, 1981-82, and 1982-83

| | Winter heating season | | |
|---|---|---|---|
| | 1980-81 (note a) | 1981-82 (note b) | 1982-83 (note b) |
| Estimated supplies available (normal winter) | 6,286 | 6,053 | 6,653 |
| Actual supplies used | 6,038 | 6,037 | c/ 5,777 |

a/Based on data for 28 companies.

b/Based on data for 24 companies.

c/GAO estimate based on actual supplies used in 1981-82 and declines in gas utility sales reported by the American Gas Association, Monthly Gas Utility Statistical Report--August 1982. The Association reported that sales during the first 8 months of calendar 1982 were 4.3 percent below previous year levels. Residential sales (3,498 Bcf) were up 6.7 percent; commercial sales (1,728 Bcf) were up 5.6 percent; industrial and electric utility sales (4,780 Bcf) were down 13.9 percent; and other sales (192 Bcf) were unchanged. We assumed that sales during the 5-month winter heating season of 1982-83 would likewise be 4.3 percent below 1981-82 levels.

Source: FERC, Commission Staff Reports: Impact of 1981-82 Winter Gas Supply for Twenty-Eight Pipeline Companies, Docket Nos. TC81-23, et al., October 1981, p. 5, and Commission Staff Report on 1982-83 Winter Gas Supply for Twenty-Four Pipeline Companies, Docket Nos. TC82-12 et al., September 1982, p. 5.

Following the 1954 Supreme Court decision, gas sold in interstate commerce was subject to Federal price controls, although gas sold in intrastate commerce was not subject to these controls. In the early and mid-1970s, competition for new gas supplies pushed intrastate prices well above interstate prices. 1/

This imbalance led to a prolonged decline in the amount of gas reserves under the control of interstate pipelines. During the 11-year period ending in 1977, these pipelines experienced a fall in their inventory of dedicated reserves, from about 198 Tcf in 1967 to about 93 Tcf in 1977. (See table 8.) The pipelines' inventory of reserves dropped from 17 times current production levels in 1967 to 9 times current production levels in 1977. During this period gross changes in reserves (reflecting new reserves plus the net change in assessment of already discovered reserves) were low or negative. In each year gross changes in reserves were less than production. Therefore, the net change in reserves was negative during every year between 1968 and 1977.

Not only was the interstate pipelines' inventory apparently being depleted, but there were many instances in the early and mid-1970s when the pipelines could not deliver as much gas as their customers wanted and therefore had to "curtail," or restrict, purchases by some customers. These curtailments led to the shutting down of factories and schools, especially during the unusually cold winter of 1976-77.

Because of their experience with shortages, interstate pipelines were eager to purchase new supplies throughout the 1970s. Before enactment of the Natural Gas Policy Act in 1978, interstate pipelines faced restrictions in competing against intrastate pipelines and against each other on the basis of current price, so they resorted to competing on other terms. These so-called "non-price" terms included provisions governing: (1) how prices would be set if Federal price regulations ended and (2) how much of the production covered by a given contract would be purchased regularly.

After NGPA, interstate and intrastate pipelines were on a more equal footing with respect to allowable prices, but they still competed aggressively for new supplies. This aggressive competition apparently continued through 1980 and perhaps 1981, even though exploration efforts were considerably higher in those years and the interstate pipelines' reserves were again improving. (See Table 8.)

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1/According to the April 1977 National Energy Plan, "Recent contract prices for new gas in the intrastate market range from \$1.60 per Mcf to \$2.25, while the highest price ever allowed for long-term interstate gas purchases is \$1.45." See Executive Office of the President, Energy Policy and Planning, National Energy Plan, Apr. 29, 1977, p. 18.

## Table 8

### Interstate Pipeline Companies' Dedicated Reserves Changes in Reserves, Production, and Reserves-to-Production Ratios, Alternate Years, 1965-81

| Year | Dedicated reserves as of Dec. 31 | Changes in reserves from previous years: Net | Changes in reserves from previous years: Gross | Production | Reserves-to-production ratio (note b) |
|---|---|---|---|---|---|
| | (in Tcf) | | | | |
| 1965 | 192 | 3 | 13 | 10 | 19 |
| 1967 | 198 | 3 | 15 | 12 | 17 |
| 1969 | 188 | - 7 | 6 | 13 | 14 |
| 1971 | 161 | -12 | 2 | 14 | 11 |
| 1973 | 134 | -13 | 1 | 14 | 10 |
| 1975 | 107 | -14 | - 2 | 12 | 9 |
| 1977 | 93 | - 5 | 6 | 11 | 9 |
| 1979 | 97 | 3 | 15 | 12 | 8 |
| 1981 (note a) | 98 | 1 | 13 | 12 | 8 |

a/Preliminary.

b/Ratios computed from unrounded data.

Source: EIA, Domestic Natural Gas Reserves and Production Dedicated to Interstate Pipeline Companies, 1981, (Preliminary Report), DOE/EIA-0167(81)P, June 1982, table 3; and Gas Supplies of Interstate Natural Gas Pipeline Companies--1980, DOE/EIA-0167(80), Dec. 1981, table 3.

The results of this competition included

--some contracts which obligated the purchaser to pay the "highest regulated rate" for gas;

--some contracts which obligated the purchaser to purchase 80 or 90 percent of the gas which could be delivered from a given field, which severely limited the purchaser's flexibility;

--some contracts which, until the last year or two, often gave the purchaser little, if any, latitude to initiate renegotiation if the price was too high;

--some contracts to pay $9.00 or more per MmBtu for deep gas;

--some contracts with Canadian and Mexican producers to pay nearly $5.00 per MmBtu at the border; and

--considerable investments in facilities for receiving and handling imports of liquefied natural gas.

Until recently, interstate pipelines could generally sell as ich gas as they could provide. In fact, there was assumed to be ı unfulfilled demand for gas at existing prices. A report preıred for the Department of Energy estimated that there was :rustrated" or unfulfilled, demand for gas in the industrial ector of almost 2 Tcf in 1979. 1/

However, this supposed unfulfilled demand seems to have dis- ›peared, and 1982 consumption is less than 1981 consumption. ecent consumption of gas has been significantly affected by eactions to higher gas prices and by general economic conditions. ı response to sharply higher gas prices, consumers have made more :ficient use of their gas and have substituted other fuels for ıs. In response to general economic conditions, consumers have ıt back on purchases of gas used in producing various goods and ervices.

The overall effect was the potential to produce large quantiies of gas--at high prices. These high prices coincided with, and ı some measure led to, declines in consumption. Thus developed ıe current "excess supply" of natural gas. However, this situaion is not necessarily a permanent phenomenon.

## )W IS THE MARKET ADJUSTING?

In the theoretical model of a market described in a basic :onomics text, an imbalance between supply and demand quickly

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/Energy and Environmental Analysis, Inc. Industrial Gas Demand, Appendix B to "A Study of Alternatives to the Natural Gas Policy Act of 1978," DOE/PE-0034, Nov. 1981, p. 7.

leads to adjustments which equilibrate supply and demand via the price mechanism. An excess of supply over demand, for example, would be expected to lead to a lower price. The recent behavior of the natural gas market appears to diverge from the behavior predicted by the theoretical model because prices have been risi even though there is "excess supply" of gas.

Current market conditions reflect the cumulative effects of years of developments in the natural gas industry and regulation. Accordingly, it is not certain how quickly and completely the industry can and will adjust to the current "excess supply."

Natural gas markets have several characteristics which do n conform to the textbook model and which may tend to impede adjus ments. These include features of both industry structure and government regulation--which in turn are interrelated. In the former category are long-term arrangements between producers and pipelines and between pipelines and distributors; multiple owner ship interests in producing properties, which may make it more difficult to get agreement on renegotiating prices; and limited knowledge of industry developments.

In the latter category are Federal and State ceilings on wellhead prices; Federal regulations which require that a gas reservoir--once "dedicated" to interstate commerce--remains dedicated, unless FERC approves otherwise; and a pipeline's need to obtain FERC approval to increase an existing customer's level of "entitlements" or sell gas to a customer which it is not require to serve.

Nonetheless, there is some evidence that the market is responding. Examples can be found in producer-pipeline relatior pipeline-pipeline relations, and pipeline-distributor relations. This evidence is anecdotal--rather than comprehensive--because companies typically are reluctant to divulge their competitive strategy. Much of the available information has come to public attention through FERC proceedings.

In pipeline dealings with producers, perhaps the most dram evidence of industry adjustment to changed conditions relates to purchases of high-cost (section 107) gas. This category consis mostly of deep gas (whose price is unregulated) and tight-sands gas (whose price is regulated at a relatively high rate). According to the September 1982 EIA study, 1/ the average price paid by major interstate pipelines for section 107 gas increased fro $6.12 an Mcf for mid-1981 filings to $7.33 an Mcf for late 1981 to early 1982 filings, but declined to $7.24 an Mcf for mid-198 filings (all prices in constant January 1982 dollars).

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1/Energy Information Administration, An Analysis of Post-NGPA Interstate Pipeline Wellhead Purchases, DOE/EIA-0357, Sept. 1982, p. 28.

Moreover, some pipelines have exercised "market-out" clauses ı contracts for the purchase of deep gas. Transcontinental Pipe-ne exercised its "market-out" clauses in May 1982; it offered › pay $5.00 per MmBtu, according to a company representative. ıree other pipeline companies (United, Michigan-Wisconsin, and ːnnessee) have exercised their "market-out" clauses since then, ːcording to their representatives.

In addition, Southern Natural asked its suppliers this past ımmer to voluntarily reduce their deliveries because its pipe-.nes and storage fields were full and its customers were using ːss gas than expected, according to a company representative. ›lumbia is renegotiating contracts with its suppliers to provide ›r lower prices and lower purchase obligations, according to a ›mpany representative.

In terms of pipeline dealings with other pipelines, it should ː noted that many pipelines purchase gas from other pipelines. ːcording to the September 1982 EIA report, 9 of 20 major inter-ːate pipelines bought at least 2 percent of their supplies from ːher pipelines. Columbia Gas Transmission notified five pipeline ıppliers in August 1982 that it would neither take nor pay for ›lumes required by its arrangements with those other pipelines, ːcording to a company representative. Columbia cited a precipi-›us and continuing deterioration of the markets it serves.

Finally, pipelines' dealings with distributors are also ,olving. Some pipelines (including Columbia and Michigan-Wiscon-ın) have applied to FERC for approval of a temporary discount ıte for industrial customers. These rates are available for pipe-ıne sales to distributors, for resale to qualified industrial cus-›mers. Such lower rates are designed to discourage major indus-ːial users from switching from gas to another fuel, such as resi-ıal fuel oil.

In summary, although most of the information is anecdotal, ıere is a growing body of evidence that the natural gas market ɜ acting to reduce prices and otherwise adjust to the current ɜxcess supply."

## ƆNCLUSIONS

Reports of an "excess supply" of natural gas are consistent ith major pipeline estimates of supplies which will be available ıis winter. This situation reflects the many factors which de-ɜrmine gas production and consumption. Until recently, pipelines ɔuld generally sell as much gas as they could provide and eagerly ɔught new supplies.

However, there no longer seems to be any unfulfilled demand t current prices, and consumption through the first 8 months of 982 was below the comparable 1981 level. The current situation hus resulted from pipelines' potential to supply large quanti-ies of gas and a coincident decline in gas consumption.

Some companies are adjusting to the current situation, by exercising "market-out" clauses, renegotiating contracts, and oth er means, according to their representatives. However, various industry and regulatory characteristics may act to impede the pac of adjustment.

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