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BY THE COMPTROLLER GENERAL

Report To The Subcommittee On Environment, Energy And Natural Resources, House Committee On Government Operations

OF THE UNITED STATES

An Analysis Of Natural Gas Pricing Policy Alternatives

Volume I Of 2 Volumes (Analysis And Conclusions)

Several alternatives have been proposed to the Natural Gas Policy Act, which established a schedule for decontrol of natural gas prices. GAO examined four proposals to see how they compared in their effects on gas prices and supplies.

This report summarizes the results of GAO's analysis and discusses the advantages and disadvantages of the two more attractive options--continuing the provisions of the present law and total decontrol of natural gas wellhead prices in 1983.

GAO points out that should the decision be made to decontrol natural gas prices in 1983, the issue of what to do with existing contracts--which is the most serious problem under decontrol--will have to be addressed.

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COMPTROLLER GENERAL OF THE UNITED STATES
WASHINGTON D.C. 20548

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Chairman, Subcommittee on
Environment, Energy and
Natural Resources
House Committee on Government
Operations

Dear Mr. Chairman:

In response to the request of former Chairman Toby Moffett dated August 28, 1981, this report presents the results of our evaluation of the energy and economic impacts of alternative options for regulating natural gas wellhead prices. The report discusses both national economic impacts and related institutional issues such as producer/pipeline contracts for five separate natural gas regulatory alternatives.

We did not obtain official agency comments on this report.

Sincerely yours,

Milton J. Socolar

Acting Comptroller General
of the United States

COMPTROLLER GENERAL'S REPORT TO THE SUBCOMMITTEE ON ENVIRONMENT, ENERGY AND NATURAL RESOURCES, HOUSE COMMITTEE ON GOVERNMENT OPERATIONS

AN ANALYSIS OF NATURAL GAS PRICING POLICY ALTERNATIVES

D I G E S T

Passage of the Natural Gas Policy Act (NGPA) in 1978, capping years of debate, was expected to settle the issue of natural gas pricing. Over several years, prices for various categories of gas discovered after 1977 would be released from regulation with total decontrol of new gas occurring in 1985. Although the price of most of the gas discovered prior to 1977 would remain controlled, depletion would steadily reduce its influence. The gas market would thus make a smooth transition to decontrol.

Substantial increases in consumer prices for natural gas have caused public concern about the smoothness of the transition to total decontrol under NGPA. One concern is over current price increases which have occurred even though gas supplies have been more than sufficient to meet demand. Another is the possibility that natural gas wellhead prices will increase substantially once controls are lifted.

These concerns have led to the proposal, by both government and private officials, of numerous alternatives to the NGPA. GAO analyzed the energy and economic impacts of current law and what it believed are key proposals to modify the law. The options analyzed are:

--NGPA, as enacted in 1978,

--NGPA Extended would continue NGPA price controls through 1990,

--NGPA Adjusted would have the Federal Energy Regulatory Commission raise prices of gas found between 10,000 and 15,000 feet underground and old gas. Other aspects of the NGPA would remain as is,

--Phased Price Decontrol would increase gas prices to 70 percent of crude oil prices with total wellhead price decontrol in 1985, and

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--Price Decontrol In 1983 would decontrol all wellhead gas prices in 1983.

METHODS AND ASSUMPTIONS

Information obtained through econometric modeling, analysis of existing data and other studies, and extensive interviews with government and industry experts was combined to assess the energy and economic impacts, at the national level, of each option for the period 1982 through 1990. Econometric analysis is sensitive to underlying assumptions, with different assumptions yielding different results. As such, the results of GAO's quantitative analysis should be viewed as estimates and taken cautiously by the reader.

GAO based its assumptions on available information regarding the level of present and expected economic conditions and the provisions of producer/pipeline contracts. To test the reasonableness of the assumptions GAO compared its results to other major natural gas studies and conducted an extensive sensitivity analysis using alternative assumptions.

GAO's results are very sensitive to two key assumptions--future oil prices and the effects of contract provisions between natural gas producers and pipelines. The complexity of the issues also led to GAO's decision to analyze the economic or market-related issues separately from the issues concerning the provisions of producer/pipeline contracts. Determining which natural gas policy is best requires consideration of both economic and institutional factors such as existing contract arrangements.

FINDINGS

The current law and four proposals were examined to see how they compared in their effects on gas prices and supply. GAO found that while no alternative emerges as clearly superior, the present law and the proposal to totally decontrol prices in 1983 offer the best results with the fewest disadvantages. The remaining three alternatives--Phased Price Decontrol, NGPA Adjusted, and NGPA Extended--yielded less favorable results. The first two set ceiling prices higher than necessary to clear the market* and have few compensatory benefits. The NGPA Extended approach could create natural gas shortages in 1985 and there after. (see pp. 7-11).

Analysis of Market Forces

The results of GAO's economic analysis showed little difference in gas prices, production, producer revenues, or consumer costs between NGPA or Price Decontrol in 1983 due to market forces alone. Gas prices are approaching those necessary to clear the market and there is little economic justification for extraordinary price increases either in 1983 under total price decontrol or in 1985 under current law. Prices under Price Decontrol In 1983 would increase 18 percent in that year, while under NGPA, the increase would be 13 percent in 1985 (the first year of partial decontrol under NGPA). For comparison, average wellhead prices under NGPA have increased at approximately 21 percent per year since 1978. (see pp. 9-21).**

These market induced price increases are less than many have feared would be the case because oil prices and natural gas demand has declined while natural gas prices have increased at a faster rate under NGPA than originally anticipated. NGPA does provide a smoother path to decontrol and results in slightly lower prices throughout the 1980s than Price Decontrol In 1983 (see pp. 12 and 13).

Due to the competitiveness of oil and natural gas as substitute fuels, however, these results are very sensitive to alternative oil price assumptions. If assumed oil prices are 25 percent higher, wellhead prices under NGPA increase 37 percent upon partial decontrol in 1985--making NGPA prices slightly above Price Decontrol In 1983 prices in that year. Even with higher oil prices, however, the difference

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*A price which "Clears the Market" is defined as the price which equates the supply and demand for natural gas.

**All percent figures are based on 1980 real dollars.

between NGPA and Price Decontrol In 1983 is still largely a question of when the deregulation price increase occurs. With either higher or lower oil prices, the percent difference in wellhead prices over three years between NGPA and total decontrol is small--ranging from 1 to 4 percent. (see pp. 12 and 17).

The closeness of results between these two options is reflected in the economic impacts on both producers and consumers. GAO's analysis revealed that market forces would cause consumer costs from 1983 through 1985 under Price Decontrol In 1983 to be about 3 percent higher than under NGPA. During the 3 years, natural gas producers would collect $8 billion more (pre-tax, current dollars) under Price Decontrol In 1983--5 percent more than under NGPA (see pp. 13 and 14).

Price Effects of
Contract Provisions

Upon partial or total price decontrol, certain pipeline contract provisions could boost the cost of gas substantially above market clearing prices, especially in the case of Price Decontrol in 1983 (see pp. 24 and 25).

Existing contracts could raise some wellhead gas prices to 110 percent of the delivered price of fuel oil. This would make the price of gas to the ultimate consumer about twice as high as the delivered price of fuel oil and would render the gas unmarketable. However, the amount of gas which will be priced at that level is highly uncertain as is the amount that overall gas prices could exceed market levels. These factors are examined in more depth in a companion GAO study.* (See pp. 24-29).

GAO estimated that the effect of the contract problem under NGPA is a range from no appreciable change in gas prices to interstate gas price increases of as much as 30 percent over market-clearing prices. GAO's analysis of the

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*This report which examines issues concerning natural gas producer--pipeline contracts should be released in early 1983.

admittedly incomplete evidence points to an increase of about 10 percent as being most plausible. When combined with the 13 percent real increase in prices caused by market forces under NGPA, the potential increase ranges from 13 to 47 percent with the most likely figure being about 24 percent (see p. 35).

A contract-induced price increase would be potentially more serious under Price Decontrol In 1983. This is largely because, first, the gap between oil and gas prices will be greater in that year, and second, a larger number of contracts would be affected. Specifically, a contract-induced price increase could range anywhere from no appreciable change to as high as 80 percent above 1983 market clearing prices, the most plausible increase being about 60 percent. In this case, the combined impact from market forces and contracts leads to a potential price increase ranging from 18 to 110 percent with about 88 percent being most likely. Eighteen percent of this would result from market forces with the rest being contract-related (see pp. 34-35).

GAO did not attempt to estimate the impacts of these contract induced price increases on consumers or producers. Uncertainty about the size and likelihood of a price increase along with questions such as how State regulators would deal with these increases make any estimates highly speculative.

Effects of the "Cushion" Problem

In contrast to the contract problem, the so-called "cushion problem," where interstate pipelines may gain a competitive advantage over intrastate pipelines, would only be a serious problem under NGPA beginning in 1985. The "cushion" consists of old, (pre-1977) gas purchased by interstate pipelines under long term contracts at prices lower than old intrastate gas. Under NGPA, price controls remain on a substantial portion of this old interstate gas after 1985. This low cost, price controlled gas will enable interstate pipelines to bid abovemarket prices for new, decontrolled supplies, average the two prices, and still maintain a competitive market price.

Intrastate pipelines are concerned that interstate pipelines, having the ability to bid higher prices for new gas, will capture most new supplies after 1985. According to GAO's analysis, however, this bidding advantage appears to be short-lived, because the cushion of cheap gas is depleted fairly quickly. Although at the beginning the disparity could be as high as 23 percent (or higher if oil prices rise more rapidly), by 1990 the difference in the prices paid for gas by inter- and intrastate pipelines should be about 8 percent. Since under Price Decontrol In 1983 wellhead price controls are lifted on both inter- and intrastate gas the size of the cushion would be substantially reduced, eliminating the problem.

CONCLUSIONS

Because the effects of contracts are uncertain and because the results of GAO's economic analysis of Price Decontrol In 1983 and current law are so close, neither of these two options stands out as being superior. GAO does believe, however, that either of these policies is preferable to the other three alternatives. Price Decontrol In 1983 promises to alleviate many of the disadvantages suffered by intrastate pipelines inability to compete with interstate pipelines for gas. It also increases economic efficiency earlier through higher natural gas prices which promote greater conservation, more optimal fuel choices, and least cost gas supplies. The NGPA offers a smoother increase to decontrol levels and lower consumer prices overall. Further, based on GAO's analysis the contract problem is less severe under the NGPA than under Price Decontrol In 1983.

In essence, when economics and market forces alone are considered, there appears to be very little difference between the options. When the admittedly less clear contract and institutional factors are also considered, however, the potential price increase is much greater under total decontrol, while the "cushion" problem exists only under NGPA. The most serious problem is the potential impact on wellhead price from producer/pipeline contracts. Although there is general agreement that provisions of existing contracts create the potential for a contract-induced price increase, there is no agreement about how large such an increase would be and what Federal action--if any--is warranted. Many analysts believe there would be a great deal of private negotiation over contract provisions and, very possibly, extensive litigation. Proposed remedies include letting pipelines and producers work things out privately, administrative action by the Federal Energy Regulatory Commission, and new legislation.

Both current law and Price Decontrol In 1983 have advantages and disadvantages. Thus, GAO's analysis indicates there is no clear reason to change the current price deregulation schedule from that established by NGPA. However, if decontrol in 1983 is selected, the contract issue--which is the most serious problem under decontrol--needs to be addressed.

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Information in this report was prepared at the request of the former Chairman, Subcommittee on Environment, Energy and Natural Resources, House Committee on Government Operations, and should be useful to the Congress in its further evaluation of Natural Gas issues and concerns. GAO did not obtain agency comments.

CONTENTS

ABBREVIATIONS

AGA	American Gas Association
bbl	Barrel of crude oil
Btu	British thermal unit
DOE	Department of Energy
DRI	Data Resources Incorporated
EIA	Energy Information Administration
FERC	Fedeal Energy Regulatory Commission
FPC	Federal Power Commission
GAO	General Accounting Office
LNG	Liquefied Natural Gas
MCF	1000 cubic feet
MM/Btu	Million British thermal units
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act of 1978
OCS	Outer Continental Shelf
QUAD	Quadrillion British thermal units
SNG	Synthetic Natural Gas
Tcf	Trillion cubic feet

CHAPTER 1

INTRODUCTION

The price that pipelines charge for natural gas to interstate markets has been regulated since the Natural Gas Act of 1938. The Act required the Federal Power Commission (now the Federal Energy Regulatory Commission) to regulate the interstate transportation of natural gas by controlling the price, conditions of sale, and the rate of return earned by interstate pipelines. However, it was not until the Supreme Court decision in 1954 (Phillips Petroleum Company vs. Wisconsin) that the Commission's authority was expanded to include the initial price of interstate gas at the wellhead.

FPC regulation kept interstate natural gas prices below those in the intrastate market. During the 1960's, shortages of gas for customers outside the producing states began to develop. Shortages occurred because of producer unwillingness to sell new reserves to the regulated interstate pipelines when intrastate buyers were paying higher unregulated prices.

As a result, consumption exceeded new natural gas discoveries and reduced proved reserves. Between 1956 and 1970, exploratory drilling dropped by more than 50 percent and proved reserves in the lower 48 States dropped from 23 to 9.7 times the annual production rate. Less drilling, increased demand, and the price disparity between the interstate and intrastate markets led to a major shortage in the interstate market. In the face of inadequate supplies, pipelines were forced to curtail sales. Interstate industrial and electric utility customers were curtailed and new hookups were banned. The extremely cold winter of 1976-77 resulted in curtailments which reached commercial users, schools and some residential areas and brought the true magnitude of the gas supply problem into focus.

THE NATURAL GAS POLICY ACT--ATTEMPTING TO SOLVE MARKET PROBLEMS

The 95th Congress enacted legislation in 1978 to deal with the supply problem. The Natural Gas Policy Act of 1978 (NGPA) substantially changed the regulation that had developed since the 1954 Supreme Court decision.

The NGPA consists of six titles addressing a variety of issues. Title I of the Act, the most important to the issues addressed in this report, generally brought intrastate gas (gas produced and sold within a single state) under Federal regulation for the first time. In so doing, it established over 20 categories of natural gas prices which can be distilled into 4 major sections. They are

1. new (post 1977) gas, most of which receives a 3 to 4 percent annual price increase above inflation and is decontrolled in 1985,

2. old (pre 1977) interstate gas which remains controlled until exhausted,

3. old (pre 1977) intrastate gas, some of which is scheduled for deregulation in 1985 with the remainder being controlled at prices higher than old interstate gas, and

4. certain types of high cost gas, particularly that found below 15,000 feet (whose price was deregulated in 1979).

Approximately 50 percent of all domestic gas will be decontrolled in 1985, rising to approximately 75 to 90 percent by 1990. The majority of remaining controlled gas would be interstate gas.

Generally, the purpose of NGPA was to allow higher prices for "new" gas in order to increase supply while at the same time continuing price controls on "old" gas to keep consumer prices as low as possible. Gas prices under NGPA were to increase by specific increments plus a monthly inflation factor. By January 1, 1985, the price of new gas was to approximate an oil equivalent price of $15 per barrel (in 1977 dollars). This price escalation schedule was intended to prevent a substantial price increase in 1985. Unfortunately, the NGPA did not anticipate the doubling of oil prices in the wake of the Iranian revolution. Therefore, by 1981 it appeared unlikely that natural gas prices under the NGPA would reach crude oil parity by 1985.

CURRENT ISSUES IN THE NATURAL GAS DEBATE

Congress has shown substantial concern about how quickly to decontrol gas prices and the resulting consequences. Several economic and institutional issues stand out in the debate.

The first issue is how much natural gas prices will "fly-up" 1/ in 1985 when decontrol takes effect. A "fly-up" could occur from either market forces or contractual arrangements. The market "fly-up" could happen because the targeted oil price of $15 per bbl (1977 dollars) set in 1978 has turned out to be

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1/A common term presently used in the natural gas industry to depict a price increase substantially above that which would normally occur in the natural gas market.

substantially below current crude oil prices. Therefore, gas prices could rise rapidly and substantially affect consumers and worsen inflation.

On the other hand, there also appears to be a potential for a price "fly-up" resulting from gas contract provisions. Based on available information, it appears that most contracts include pricing provisions allowing for redetermination of prices upon deregulation. The concern is that upon deregulation, clauses referencing gas to 110 percent or more of the price of No. 2 fuel oil or to the highest (or one of three highest) prices in an area could trigger large price increases for a substantial amount of gas.

A second significant issue is the effect of decontrol on supply. There is disagreement over whether trends of increasing production, proved reserves and drilling activity since NGPA will continue under decontrol. Some argue that drilling decisions are based on future price expectations. If this is true, producers should have added incentive to develop new gas reserves which can be sold at high prices. However, since prices for most new gas remain controlled until 1985, a short run disincentive may exist. Furthermore, in today's market, demand for gas is soft and this could also constrain production. Thus, the effect of decontrol on supply remains uncertain.

A third decontrol issue is the extent to which interstate and intrastate pipelines can compete equally. Since controlled gas prices on previously committed supplies of old interstate gas are low, the interstate market has considerably more cheap gas. This "cushion" of low cost gas may allow interstate pipelines to bid new decontrolled supplies away from the intrastate pipelines by paying above-market prices and averaging them with low cost gas. The intrastate pipelines, lacking this supply of low cost gas from the pre-NGPA period, may not be able to bid adequate prices for new gas. As a result, intrastate pipelines are concerned that interstate pipelines will capture most new supplies after 1985.

OBJECTIVES, SCOPE, AND METHODOLOGY

This report was initiated at the request of Chairman Toby Moffett of the House Subcommittee on Environment, Energy, and Natural Resources. Specifically, the Chairman asked us to provide an analysis of the natural gas supply and demand responses under differing policy options along with their effects on natural gas producers and consumers. Among the numerous proposals to deregulate natural gas wellhead prices, our report considers five different options, which GAO felt were most realistic. They are

1. continuation of NGPA as is;

2. suggestions that the Federal Energy Regulatory Commission (FERC) raise gas prices on gas found between 10,000 and 15,000 feet and "old" gas (NGPA Adjusted);

3. extension of the NGPA to 1990 but maintaining the current growth rate of prices (NGPA Extended);

4. increasing gas prices to 70 percent of crude oil by 1985 (Phased Price Decontrol);

5. Price Decontrol In 1983.

Each scenario was analyzed using both low and high oil prices and low and high economic growth assumptions. 1/ We projected oil price for the 1980's by polling a number of Federal Government and industry experts. Our low oil price scenario begins with oil at $28.50 in 1982, 2/ remaining constant in real terms until 1985. After 1985, oil prices increase to $32.70 ($66.30 in 1990 dollars) in 1990. In contrast, our high oil price case assumes a 1982 price of $32.70, increasing to a 1990 price of $41.50 ($84.20 in 1990 dollars).

The future domestic natural gas supply/demand estimates we make cannot be considered definitive. They are intended to serve as a reasonable basis for comparative analysis of regulatory options. Our purpose is to provide a balanced view of the effects of potential policy options. Throughout this report, for comparison and consistency between estimated forecasts, all numbers are reported in 1980 dollars unless stated otherwise.

In preparing this study, we reviewed our past work consisting of five related reports. The GAO report centering most directly on the issues addressed here was "Implications of Deregulating the Price of Natural Gas," (OSP-76-11) published in 1976. Although much of the outlook for natural gas has changed since this study was completed, we believe that its conclusion that domestic, conventional natural gas production will continue to decline remains valid. Two other GAO reports focused on gas supply from a domestic and international standpoint--they were "Analysis of Current Trends in U.S. Petroleum and Natural Gas Production" (EMD-80-24) and "Oil and Natural Gas from Alaska, Canada, and Mexico--Only Limited Help for U.S." (EMD-80-72). Both studies were used for comparative purposes in determining potential supply. In addition, GAO issued a report in 1981 entitled "Changes in Natural Gas Prices and Supplies Since Passage of the Natural Gas Policy Act of 1978" (EMD-81-73).

1/Oil prices are defined as average refiner acquisition cost of crude oil.

2/In 1980 dollars. This price in current dollars is $34.

A producer survey used in that study highlighted a relationship we explore further in this report--the relationship between the price of natural gas and drilling activity. Finally, we relied extensively on the information provided in a forthcoming GAO report which examines issues concerning natural gas producer-pipeline contracts.

Over the past several years numerous studies have been completed on natural gas decontrol. In preparing our report, we reviewed and evaluated all the major ones, particularly those completed recently which reflect the current regulatory climate. These included studies by the Department of Energy, the Natural Gas Supply Association, the American Gas Association, and the Congressional Budget Office as well as consulting groups such as Lewin Associates and Erickson Associates. Each of these studies used different approaches and data and often reached divergent conclusions.

Our analysis of natural gas decontrol relies on econometric modeling, close analysis of existing data and other studies, and extensive interviews with Government and industry experts and representatives. Among the latter, we interviewed representatives of over 80 industrial gas users, 60 commercial users, 25 powerplant users and 55 gas distributors. The report combines all three approaches to provide a crosscheck on our results and to give a balanced view.

By using these methods, we developed future supply and demand curves for each scenario between 1982 and 1990. Once our supply and demand relationships were derived, we combined them to calculate the market price and quantity of gas. Throughout the report we assume that supply and demand will respond to regulated maximum allowable ceiling prices. The results under NGPA represented our base case, and the impact of each scenario was then analyzed as changes from this base case. The quantitative results of this report should be taken cautiously; specifically, although the results are based on accepted economic theory and research techniques, the results must be viewed only as estimates. As with any modeling effort, certain variances will exist from the true value of variables being estimated or forecasted. For this reason, Chapter 3 provides both a sensitivity analysis on our results and a comparison with the assumptions, methods and results of other major natural gas studies. An extensive discussion of our methodology can be found in Volume II of this report which is available from GAO on request.

Specifically, conventional gas supplies were estimated according to the following logic: prices determine drilling rates which in turn influence reserve additions; these alter the proven reserve base; that base along with prices determine annual production. At each stage in this chain our estimations were done econometrically and depended on prices and other factors as appropriate. These factors included interest rates and historical trends in reserve-to-production ratios. Supplemental gas supplies were analyzed outside the model through extensive interviews and review of current work in that area.

We projected gas demand as a function of price by dividing total gas demand into four subsectors--industrial, residential, commercial, and powerplant. Gas demand for each subsector was determined by (1) estimating total fuel demand in each subsector; (2) estimating and subtracting away the use of fuels other than oil and gas in each subsector; and (3) estimating the split between oil and gas for the remaining fuel demand. Other considerations, such as the relative attractiveness of gas versus electricity for space heating, and regional limitations on gas transmission capacity, were also considered.

Our supply and demand analysis represents the economics of natural gas in the absence of any non-market constraints which would not allow the forces of supply and demand to reach a market-clearing equilibrium. The potential impacts of these constraints are discussed in detail in Chapter 4.

This review was performed in accordance with generally accepted government audit standards.

CHAPTER 2

COMPARING ENERGY AND ECONOMIC IMPACTS OF NATURAL GAS REGULATION ALTERNATIVES

This chapter compares the market induced energy and economic impacts, at the national level, of alternatives to existing natural gas regulation. As such, we used the NGPA as a base line for measuring the impact of alternatives. The estimated impacts of various decontrol options focus primarily on market clearing prices and quantities which are defined as those resulting from the free interaction of supply and demand. Institutional factors could, however, alter these results. For example, intrastate users may experience a fly-up in price even though interstate users do not; the operation of certain kinds of gas contract clauses may raise prices sharply for all users. We discuss some effects of the more significant institutional factors in Chapter 4.

We conducted our analysis while assuming an energy and economic environment of low oil prices and high economic growth throughout the 1983-1990 period. 1/ Since there are many uncertainties which can influence the future, Chapter 3 presents an analysis of the sensitivity of our results to changes in these energy and economic assumptions.

Our analysis of the regulatory alternatives revealed that market forces alone would not make a substantial difference in the production or price of natural gas, or producer profits and consumer bills. We must stress that these are nationwide or average impacts. The impact on individual companies or regions of the country could be larger. What differences there are become largely a question of timing or the different effects each alternative has on the numerous categories of natural gas prices. The results in the various cases are similar because each alternative to NGPA (except NGPA extended) moves the natural gas market quickly to an essentially decontrolled situation.

NGPA gas prices from 1983 through 1985 approximate those under total decontrol because oil prices have remained stable, some categories of gas have increased in price more than expected or have been reclassified to obtain higher prices, gas demand has declined, and natural gas supplies have been adequate. Our major finding(s) for each alternative can be summarized as follows:

1/Oil prices are defined as average refiner acquisition cost of crude oil. For our base case, we assume that oil prices will stay flat at $34/barrel through 1982, whereupon they will rise with inflation through 1985, and then rise 2.5 percent in real terms annually through 1990.

NGPA

--Wellhead prices under NGPA would average less than 5 percent below a decontrolled market-clearing price for natural gas.

--The 1984-85 fly-up in average natural gas wellhead prices would amount to approximately 13 percent in constant dollars. 1/

Price Decontrol In 1983

--In 1983, total decontrol would result in 7 percent higher prices than under NGPA in that year. By 1985, the price difference between "NGPA" and "Total Decontrol" is less than 3 percent.

NGPA Extended

--Although extending price controls would lower prices, it could create some supply shortages by the mid-1980s.

Phased Price Decontrol and NGPA Adjusted

--These options set ceiling prices higher than necessary to clear the market. This would be unnecessarily disruptive.

SUPPLY, DEMAND, AND PRICE EFFECTS OF ALTERNATIVE SCENARIOS

Table 1 presents our supply and price results from our model for 1982 through 1990 under alternative scenarios. For the pre-1985 years, except for "Price Decontrol In 1983", we report changes in both the level of demand and supply in response to each alternative. Except for "Price Decontrol In 1983", regulated prices do not fully clear the market before 1985 and we report changes in demand and supply separately. We report a single market-clearing quantity and price for all scenarios starting in 1985.

Probably the most interesting result of the analysis is that between 1983 and 1985 the current regulatory regime would give results close to those which would occur from "Price Decontrol In 1983", thus, GAO's analysis of market forces alone would not argue in favor of either option as being superior. Average wellhead prices under "NGPA" roughly balance supply and demand at levels comparable to those under "Price Decontrol

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1/This conclusion is very sensitive to oil price assumptions. Under our high oil price assumption discussed in Chapter 3, the 1984-85 fly-up is 37 percent (See p. 24).

In 1983." Between 1982 and 1985, NGPA ceiling prices result in demand which is only 1 percent higher than supply and within 2 percent of "Price Decontrol In 1983." At the same time, differences in price between "NGPA" and "Price Decontrol In 1983" slowly converge and nearly disappear by 1985. NGPA prices are 6 percent lower in 1983, 5 percent in 1984 and less than 3 percent by 1985. After 1985, NGPA prices slowly diverge from "Price Decontrol In 1983," becoming 6 percent lower by 1990.

Under "NGPA Extended," results are the same for 1982 through 1984 (see Table 1). However, in 1985 a gap begins to develop as NGPA price ceilings constrain supply while stimulating demand. This could result in gas curtailments by 1985-87. By 1990, NGPA price ceilings would be above total decontrol levels and supply exceeds demand by 1.4 trillion cubic feet (Tcf). However, such prices would not be sustainable due to falling demand and would actually be lower if this alternative were followed. This makes the not so obvious point that regulations which set prices above market-clearing levels have no effect on supply or demand since market forces would cause prices to be set at a lower level.

Both the "NGPA Adjusted" and "Phased Price Decontrol" scenarios reemphasize this point. As noted earlier, the average wellhead prices for "NGPA Adjusted" and "Phased Price Decontrol" represent estimates of the maximum prices allowed by the regulations. The quantities represent how supply and demand would respond to these prices. However, as shown in Table I, "NGPA Adjusted" results in excess supply throughout the 1982-84 period. Thus, before decontrol takes place in 1985, the market would actually clear at a price and quantity somewhat below that indicated in Table I. These would probably be very close to those obtained under current NGPA ceiling prices. The "Phased Price Decontrol" scenario, beginning in 1983, has similar impacts. By raising prices above the implied free market level, it results in excess supply in 1983 and 1984. This indicates that an average price ceiling based on a 70 percent of crude oil formula is too high. Our analysis of "Price Decontrol In 1983" indicates that the market would clear at an average wellhead price of approximately 50 percent of crude oil. Thus, under "NGPA Adjusted" and "Phased Price Decontrol," the market, beginning in 1983, would clear at prices and quantities very close to those obtained under "Price Decontrol In 1983."

Thus, both the "NGPA Adjusted" and "Phased Price Decontrol" scenarios set ceiling prices higher than necessary to clear the market. Further, the market-clearing prices and quantities reported in 1985 and 1990 under these two scenarios should be looked at as only hypothetical since they are based on higher prices (hence higher supplies) in the pre-1985 period than would actually occur. It seems highly questionable to pursue a change in policy such as "NGPA Adjusted" or "Phased Price Decontrol" which, due to market forces, would have results similar to either

Table 1

Changes in Prices and Quantities of Natural Gas

Under Alternative Decontrol Scenarios

(1982-1990)

Scenarios	Changes in Prices 1/ ($ per million Btu/1980)				
	1982	1983	1984	1985	1990
NGPA Base	2.07	2.29	2.52	2.85	3.30
NGPA Extended	0.0	0.0	0.0	- .09	+ .48
NGPA Adjusted	+ .27	+ .42	+ .38	- .20	+ .10
Phased Price Decontrol	0.0	+ .44	+1.00	- .25	+ .22
Price Decontrol In 1983	0.0	+ .15	+ .14	+ .08	+ .20

	Changes in Quantity 2/ (Tcf)				
	1982 D/S	1983 D/S	1984 D/S	1985 D/S	1990 D/S
NGPA Base	19.9/19.9	19.5/19.3	19.1/18.8	18.4	16.9
NGPA Extended	0/0	0/0	0/0	+.3/-.1	-1.4/+0
NGPA Adjusted	-.5/0	-.8/+.1	- .8/+.4	+.5	-.3
Phased Price Decontrol	0/0	-.8/0	-2.5/+.4	+.6	-.6
Price Decontrol In 1983	0/0	-.3/-.1	- .3/-.0	-.1	-.6

D - Demand

S - Supply

1/National average wellhead price includes Section 110 costs, severance and other taxes.

2/Total national gas supply including net imports and supplemental.

current policy or total decontrol. Both could prove to be unnecessarily disruptive and time consuming in terms of administrative and legal requirements, market uncertainties and political costs.

Because the "NGPA Adjusted" and "Phased Price Decontrol" cases would yield results similar to either the base case or "Price Decontrol In 1983," the rest of our analysis revolves around differences between "NGPA" and "Price Decontrol In 1983." Table 1 shows that "Price Decontrol In 1983" causes prices to rise by 37 cents (18 percent) in 1983 while NGPA yields a 22 cent (11 percent) price increase. For comparison, average wellhead prices under NGPA have increased at approximately 21 percent per year (about 28 cents) since 1978. By 1985, average wellhead prices are only 8 cents apart and quantities are approximately equal under the two scenarios. In 1990, "Price Decontrol In 1983" prices are $ .20/MMBtu higher while supply is .6 Tcf lower than under the "NGPA" base case. The difference in price increase from 1982 to 1985 is less than 4 percent, and over the entire 1982-90 period 10 percent. In fact, throughout the period, "NGPA" results in slightly lower prices and higher production than in the "Price Decontrol In 1983" case. The greater supply response under "NGPA" results from producers receiving a higher price for new, decontrolled gas which provides an incentive for increased drilling. The ability of interstate pipelines to average low and high cost gas, since "NGPA" continues controls on certain categories of gas, enables them to bid these higher prices.

The fact that "Price Decontrol In 1983" would result in slightly higher prices throughout the 1983-1990 period (the largest being 7 percent in 1983) raises the possibility that economic efficiency gains could be realized through "Price Decontrol In 1983." Although the potential for such gains does exist, we did not attempt to measure their magnitude. However, the relative closeness between scenarios of average wellhead prices as compared to other studies (DOE, DRI, AGA) seems to indicate that these efficiency gains would not be large.

<u>The price fly-up issue</u>

The price fly-up which we examine in detail here could occur through the forces of supply and demand operating within the regulatory environment dictated by each scenario. Another type of fly-up in prices could be due to provisions contained in existing producer-pipeline contracts. This question is addressed in Chapter 4.

Our economic analysis sees natural gas prices being set by the forces of supply and demand in end-use markets. Because transmission and distribution costs are basically fixed, average wellhead prices are directly related to these end-use prices. It becomes very important, therefore, to determine the level of average wellhead prices under differing policies. Table 2 presents the percent increases in average wellhead price for each year for the "NGPA" and "Price Decontrol In 1983" cases.

As can be seen from Table 2, the overall increase in average wellhead prices over the 1982-85 period is similar under "NGPA" and "Price Decontrol In 1983." "NGPA," however, results in a smoother price path with the annual increase in real prices averaging 11 percent throughout the period with a 13 percent increase upon partial decontrol in 1985. "Price Decontrol In 1983," on the other hand, results in an 18 percent real increase in prices in 1983 with a 9-10 percent annual increase thereafter.

Table 2

Percent Increase Average

Wellhead Prices 1/

($ 1980)

Scenarios	82-83	83-84	84-85	82-85
NGPA	11	10	13	38
Price Decontrol In 1983	18	9	10	42
Difference	7	-1	-3	4

1/Percent changes are in 1980 real dollars; for nominal percent change add approximately 7 percent to numbers reported.

Thus, in terms of lessening the shock of decontrol on consumers, NGPA does a better job of smoothing the overall impact due to wellhead price increases.

CONSUMER IMPACTS UNDER ALTERNATIVE SCENARIOS

The level of average wellhead prices plus transmission and distribution charges determines the level of consumer gas bills. Thus, large increases in average wellhead prices can have a substantial financial impact on consumers.

We noted earlier that differences in average wellhead prices occur mainly between "NGPA" and "Price Decontrol In 1983" and are largely ones of timing. "NGPA" and "Price Decontrol In 1983" result in a 38 and 42 percent real increase in average wellhead prices between 1982 and 1985. However, "Price Decontrol In 1983" causes an 18 percent increase in wellhead prices in 1983 with 9 and 10 percent increases in 1984 and 1985. Under NGPA these increases average around 11 percent throughout the 1982-85 period. After 1985, we see a slow but steady real increase under both scenarios, with NGPA wellhead prices remaining slightly lower.

Prices under "Price Decontrol In 1983," and ultimately consumer costs, increase substantially in 1983 and remain slightly higher through 1990.

Compared to "NGPA" the amount of money spent on natural gas under "Price Decontrol In 1983" by the residential, commercial and industrial sectors combined would be 4 percent higher in 1983, and 1984, and 2 percent in 1985. Over the 1983-85 period, consumers would pay 3 percent more under "Price Decontrol In 1983." The average (current-dollar) residential bill in 1983 would be $775 a year as opposed to $750 under NGPA. In 1984, it would be $869 versus $843. Over the three years 1983, 1984, and 1985, residential customers would pay, on average, $67 more for natural gas as a result of "Price Decontrol In 1983."

Commercial establishments would experience slightly larger natural gas energy cost increases on average under "Price Decontrol In 1983" with 4 percent increases in 1983 and 1984 as compared to "NGPA." The average (current-dollar) commercial gas price in 1983 would increase from $5.08/MMBtu under "NGPA" to $5.29/MMBtu with "Price Decontrol In 1983." Comparable numbers for 1984 would be $5.77/MMBtu versus $5.99/MMBtu.

The amount of money spent by the industrial sector on natural gas as a result of "Price Decontrol In 1983" would be 5 percent higher in 1983 and 4 percent in 1984. By 1985 the difference is less than 3 percent. Through the 1983-85 period, the industrial sector would spend 4 percent more for natural gas as a result of "Price Decontrol In 1983." This would amount to a (current-dollar) increase in total spending of $1.3 billion in 1983, $1.3 billion in 1984, and $0.8 billion in 1985.

As can be seen from the above numbers, the difference between the two scenarios in the total expenditures for natural gas by all consumer sectors or individually over the 1983-85 timeframe is not great, averaging approximately 3 percent.

PRODUCER REVENUES UNDER ALTERNATIVE SCENARIOS

Because differences in average wellhead prices between scenarios are small, there would not be large differences in the amount of revenue flowing to natural gas producers. The revenue received by producers in any given year is simply the average wellhead price times the amount of natural gas consumed less state severance taxes and gathering costs. 1/

1/ "State severance taxes" are defined as any severance, production, or similar tax fee or other levy imposed on the production of natural gas by any State or, subdivision of State, or Indian tribe. "Gathering Costs" are defined as any costs of compressing, gathering, processing, treating, liquefying or transporting which is borne by the producer in getting the natural gas to market.

From a national policy standpoint, it is the difference in the revenue flowing to the natural gas supply industry under each scenario which is of greatest interest to national energy policy. In addition, the revenue impact a given scenario has on individual producers is difficult, if not impossible, to measure or estimate accurately. 1/ The following discussion, therefore, focuses on changes in total revenue to the entire industry.

As with consumer costs, differences in total revenues flowing to the natural gas supply sector occur mainly between "Price Decontrol In 1983" and "NGPA". Over the three year period (1983-85), natural gas producers would collect an estimated $8 billion (pre-tax current dollars) more under total decontrol than under "NGPA." This represents an increase of 5 percent. In 1983 total revenues would be $3.5 billion (7 percent) higher under "Price Decontrol In 1983." In 1984 they would be $3.5 billion (6 percent) higher. By 1985 they would be much closer as natural gas prices and quantities consumed under "NGPA "rise to levels comparable to those under "Price Decontrol In 1983." In 1990, "Price Decontrol In 1983" would result in gross revenues to the natural gas supply industry approximately $6 billion higher than under "NGPA."

Extending NGPA beyond 1985 results in approximately a $2 billion reduction in total producer revenues in 1985 compared to "NGPA." This gap in total revenue between "NGPA" and "NGPA Extended" will slowly decline over time as ceiling prices allow average prices to rise to levels comparable with those under "NGPA." By 1987 revenues would be approximately equal under both scenarios.

CONCLUSION

The main objective of this chapter has been to analyze the energy and economic impacts from alternative natural gas policies. The two central issues raised in the gas decontrol debate have been (1) will the substantial increase in oil prices which occurred following passage of NGPA result in a large fly-up in natural gas prices in 1985; and (2) what will be the difference in economic impacts on both natural gas consumers and producers.

Price fly-up

The results of our analysis provide strong evidence that NGPA prices are approaching those necessary to clear the market; thus, there would not be a large, economically induced fly-up in average natural gas prices upon partial decontrol in 1985.

1/An accurate measure of impacts on individual producers would require detailed forecasts of the price, quantity, and contractual arrangements for new versus old gas produced by each company. Given limited information on these factors, any attempt to estimate revenue impacts would be costly, time-consuming, and highly questionable.

Declining natural gas demand coupled with natural gas prices which are increasing at a faster rate under NGPA than oil prices would lead to a real price fly-up of 13 percent in 1985 under our "NGPA" case. "Price Decontrol In 1983," in comparison, would result in an 18 percent real price increase in 1983 (7 percent above "NGPA") followed by smaller increases in 1984 and 1985. Price increases from 1982-1985 under NGPA would average around 11 percent annually resulting in a smoother price path than under "Price Decontrol In 1983."

Phasing natural gas prices up to 70 percent of crude oil equivalent by 1985 results in average wellhead prices above market-clearing levels as early as 1983. Thus, the results under a "Phased Price Decontrol" scenario would be similar to those under "Price Decontrol In 1983" where the market would clear at approximately 50 percent of crude oil equivalent in 1983.

Similarly, with average wellhead prices under NGPA approximating market-clearing levels, the advantage of any attempts by the FERC to raise prices administratively seems questionable in that markets would be expected to clear before maximum allowable revenues are collected.

Consumer and producer impacts

To both consumers and producers, differences in economic impacts between decontrol scenarios occur mainly between "NGPA" and "Price Decontrol In 1983."

Consumer costs under "Price Decontrol In 1983" are 3 percent higher than under "NGPA" throughout 1983-85. Total expenditures would be 4 percent higher in 1983 and 1984 but less than 2 percent higher by 1985. The largest percent increase would occur in the industrial sector and the smallest in the residential sector. Differences in total expenditures between the two scenarios are not great. They average 3 percent from 1983 through 1985.

Between 1983 and 1985 natural gas producers would collect $8 billion more (pre-tax current dollars) under "Price Decontrol In 1983." This represents an increase of 5 percent. The largest increases would come in 1983 and 1984 when total revenues would be $3.5 billion a year higher.

CHAPTER 3

SENSITIVITY ANALYSES AND COMPARISONS WITH OTHER RESEARCH

In chapter 2 we projected that gas prices will not fly up significantly in 1985 when new gas is decontrolled under the NGPA. This conclusion is predicated on certain assumptions about the economics of the natural gas market. This chapter examines the effect that alternative oil prices and GNP growth rates have on our conclusions; it also compares our results with those of other researchers. In what follows, we will refer to the assumption used in our analysis in Chapter 2 as our "base case."

Our alternative economic scenarios include a lower economic growth case and a higher oil price case. Under our lower economic growth case, gas demand decreases for all sectors and results in less dramatic price increases for both "NGPA" and "Price Decontrol In 1983" compared to those reported in Chapter 2. However, the price spread between "NGPA" and "Price Decontrol In 1983" increases in 1985.

With our higher oil price case, gas prices in 1985 would increase almost three times as fast for "NGPA" compared to projections made in Chapter 2. This result shows that our findings in Chapter 2 are quite sensitive to changes in oil prices.

Other analyses examined include those of the Department of Energy (DOE), Data Resources Incorporated (DRI), and the American Gas Association (AGA). Our results differ most with DOE's. These differences arise because DOE assumes higher oil prices and a considerable amount of latent demand in the industrial sector. Both of these differences result in greater gas demand and, therefore, a different conclusion with respect to the pricing impacts of NGPA.

SENSITIVITY OF RESULTS TO HIGHER OIL PRICES

Our conclusion that the NGPA will not lead to a large price increase in 1985 is very sensitive to oil price assumptions. Under our high oil price assumptions, oil prices rise from a level of $28.50/barrel in 1982 (1980 dollars) to $35.70/barrel in 1985 and $41.00/barrel in 1990. 1/

1/In comparison, our base case assumption used in Chapter 2 assumed that oil prices remain constant in real terms until 1985 and then increase to $32.70 by 1990.

Table 3 presents the annual percentage change in average wellhead prices under alternative macroeconomic and oil price assumptions. As indicated in the table this higher oil price path yields an average natural gas wellhead price increase under "NGPA" of 37 percent in 1985. In our base case, by comparison, gas prices rise only 13 percent. In absolute terms "NGPA" prices in 1985 are $ .61 higher under our high oil price assumption than they are under our base case assumptions. The sharp rise in prices under "NGPA" stems mainly from the fact that higher oil prices result in higher gas demand in 1983 and 1984. By 1984, demand is about one tcf above supply; this results in sharp price increases upon decontrol.

Table 3

Price Sensitivity of Natural Gas
Under Alternative Decontrol Scenarios and Assumptions
(1982-1985)

Scenarios	Annual Percent Change in Prices 1983	1984	1985
BASE CASE			
NGPA	11	10	13
Price Decontrol In 1983	18	9	10
LOW GROWTH			
NGPA	11	10	5
Price Decontrol In 1983	6	13	13
HIGH OIL PRICE			
NGPA	11	10	37
Price Decontrol In 1983	26	16	14

Under "Price Decontrol In 1983," high oil prices increase gas prices more in each year from 1983 to 1985 compared to our base case. Although prices under "Price Decontrol In 1983" are substantially higher in 1983 and 1984, by 1985 the large price increase under "NGPA" brings them together. In 1985, wellhead prices under "Price Decontrol In 1983" are 17 percent higher than with our base case. However, due to increased supplies, they are 1 percent below those under "NGPA" assuming higher oil prices.

An overall comparison of "NGPA" versus "Price Decontrol In 1983" under our high oil price case shows that while "Price Decontrol In 1983" results in substantially higher wellhead prices in 1983 and 1984 (14 and 21 percent higher), the 37 percent fly-up under "NGPA" completely eliminates the difference. As with our base case, the difference between the two scenarios becomes largely a question of timing. Over the 3 yar period from 1983 to 1985 the percent difference in wellhead prices is approximately 1 percent. "Price Decontrol In 1983" results in higher prices sooner, while "NGPA" gives us a substantial fly-up in 1985.

SENSITIVITY OF RESULTS TO LOWER ECONOMIC GROWTH

Analysts have only recently recognized the importance of demand in the gas market. During the 1970s, potential gas demand clearly exceeded supply and there was little question of any gas which could be produced not being used. However, within the last year or two slack demand has been the main limit on gas consumption and hence production.

One reason for low gas demand is a shortfall in economic output. Our gas demand projections used to forecast market-clearing prices in Chapter 2 assumed

--that potential GNP would rise 2 3/4 percent a year,

--that actual GNP would be 93 percent of potential in 1982, 96 percent in 1983, 98 percent in 1984 and 100 percent in 1985 and thereafter, and

--that all oil-to-gas conversions in the industrial, commercial and power plant market expected by 1985 would be completed by 1982.

Our alternate economic scenario presumes that the economy works at 95 percent of potential in 1983, 96 percent in 1984 and 97 percent in 1985 and thereafter. Oil-to-gas conversions due between 1980 and 1985 are only 70 percent complete by 1982. We will refer to this as our lower growth case.

An economy whose output is lower requires less gas. Based on the relationship between GNP and fuels demand in the 1970s, we estimate that the income elasticity of gas demand is roughly one. Residential and commercial gas demand varies less over the business cycle; industrial demand varies more. We estimated that demand would be 2 percent lower in the residential and commercial sectors, 5 percent lower in the industrial sector, and 3 percent lower in the powerplant sector. Total demand in our low-demand case is three percent lower than in our base case.

As indicated in table 3, our lower growth case reduces the 1983 price fly-up under "Price Decontrol In 1983" from 18 percent to 6 percent with more substantial increases of 13 percent in 1984 and 1985. By 1985, however, the average wellhead price under "Price Decontrol In 1983" converges to what is under our base case. Lower demand, therefore, to some extent, smooths the price spike (18 percent) we encountered with "Price Decontrol In 1983" under our base case assumptions and spreads the total price increase over the 1983-1985 period.

On the other hand, lower demand results in a 5 percent increase in average well-head prices in 1985 under "NGPA" as compared to a 13 percent increase reported for our base case. The assumption of lower demand results in an average wellhead price in 1985 under the "NGPA" which is 7 percent below the level under our base case.

The important difference between our base case and our low demand case is the fact that with lower growth, "Price Decontrol In 1983" results in 1985 wellhead prices which are 6 percent higher than under "NGPA." With our base case there was only a 3 percent difference in average wellhead prices in 1985.

COMPARING OUR RESULTS WITH OTHER STUDIES

The number of natural gas policy studies produced within the last year has been substantial. Below we compare our base results with three of the most prominent studies using the best articulated models--studies by the Department of Energy 1/, Data Resources Incorporated 2/, and the American Gas Association 3/.

The DOE study

DOE's study of alternatives to the NGPA forecasts that gas prices would increase $1.84/MMBtu between 1984 and 1985 as a result of decontrol. In contrast, our NGPA case increase was $ .33/MMBtu ($ .94/MMBtu in the high oil case) over the same time period.

The differences in estimates can be ascribed to three factors. Their higher projections of crude oil prices account for 40 percent of the difference; their higher projected ratio of residual fuel oil to crude prices accounts for 20 percent; and their higher projection for potential industrial gas demand accounts for the remaining 40 percent.

DOE's 1985 crude oil price projections, the same numbers we used in our high-oil scenario, are twenty-five percent higher than our base case projections. Their projections were formulated in mid-1981 when the outlook was for higher crude prices. Our base case projections reflect the new consensus on oil prices--one which forecasts little real change up or down through 1985.

1/A Study of Alternatives to the Natural Gas Policy Act of 1978, Office of Policy and Planning, Department of Energy, Nov. 1981

2/An Assessment of the NGPA and Alternative Paths to Decontrol, Data Resources Inc., Feb. 1982

3/Total Energy Resource Analysis model (TERA), American Gas Association, (Spring 1982 version), unpublished

DOE also assumed that medium-sulfur residual fuel oil would cost 7 percent more in relation to crude than we did. The price of residual oil is a critical assumption because it determines the tradeoff between oil and gas use in industry. Residual fuel oil is now cheaper than gas in many markets. Adding to the importance of residual fuel oil is the large fraction of gas usage which occurs in combustors capable of using either fuel. Small changes in the price of either are capable of making users switch. Hence the price of residual fuel strongly influences the market-clearing price of gas. DOE projected a residual oil to crude oil ratio of 90 percent by 1985, a substantial increase over the 80 percent level maintained from 1967 to the present. We considered this unreasonable. Our projection of 84 percent presumes only a modest rise in the price of residual fuel oil.

Forty percent of the difference in our price projections is explained by DOE's higher projections for industrial gas demand. DOE assumed more energy consumption in industry than we did, in part because their conservation assumptions date back to 1979. Projections based on 1979 data do not take the last three years of vigorous industrial conservation into account. In our opinion the continuation and even strengthening of conservation trends since 1979 suggest considerable momentum for further improvements in the 1980s. The continuation of such conservation trends over time reflects the significant contribution made by the long-term renewal of the Nation's capital stock, technology, and production processes toward greater fuel efficiency.

Another reason why DOE projected more industrial demand is that it sees one to two Quadrillion Btu's (Quads) of latent demand which is supposedly frustrated by the natural gas shortage. When free to express itself in the marketplace after decontrol, this latent demand would bid away gas from other sectors. Our industrial and distributor surveys, however, found little basis for that assumption. In those cases where natural gas supply shortages led to industrial oil use, the shortage was related to the capacity limitations of local transmission or distribution systems. Since we do not believe that industrial demand (in 1981) was held back by any lack of gas supply, we see no corresponding price increase due to latent industrial demand.

The DRI study

DRI's analysis of the NGPA projects an increase of 31 percent in wellhead gas prices from 1984 to 1985. This 31 percent increase is lower than DOE's projection of 70 percent but higher than our projection of 13 percent.

If their projections of the interstate market alone are compared to our national market projections, then DRI's results substantially match ours. Their projected ratios of well-head gas to interstate industrial gas prices, interstate industrial gas to residual fuel prices, and residual to crude oil prices are nearly the same as ours. They project crude oil prices to be 9 percent higher than we do, and their baseline 1984 NGPA prices are 2 percent lower. This accounts for all the difference between their interstate and our national fly-up projections.

The main disparity is created when their intrastate projections are considered. These reflect the possibility that although there is sufficient gas to satisfy interstate customers, this is true only because the NGPA allows interstate pipelines to bid gas away from the intrastate market, thereby raising prices in that market and so the national average. Behind this possibility lies DRI's judgment that most of the fuel oil demand in the industrial sector represents potential gas demand, whose realization would increase total gas demand and hence its price. Again, our surveys do not confirm that presumption.

<u>The AGA analysis</u>

AGA's analysis of the potential price fly-up in 1985 is the most similar to ours. Both analyses see little market basis for a fly-up; AGA, however, concentrates on the potential for gas price increases that could result from the implementation of contract provisions tying gas to oil prices (see Chapter 4 for our discussion of the contracts problem). In AGA's base case, therefore, prices fly up by around 40 percent due to contract-related problems.

This fly-up leaves 1.4 QUADS of natural gas which could be produced but is priced out of the market. Applying our supply/demand relationships to their oversupply and their prices suggests that their projected market-clearing price for gas in 1985 without "contract fly-up" is virtually identical to ours.

CHAPTER 4

INSTITUTIONAL FACTORS WHICH MAY

INCREASE GAS PRICES AFTER DECONTROL

Our supply/demand projections reported in Chapter 2 indicate that there is little economic reason for a substantial fly-up of gas prices upon decontrol. Nevertheless, we have identified and reviewed three institutional factors which might have some effect on gas prices.

The interstate market, under NGPA decontrol, could have an advantage over the intrastate market in bidding for deregulated gas. This bidding advantage, according to our analysis, however, appears to be short-lived because the cushion of cheap interstate gas which remains controlled under the NGPA is depleted quickly. By 1990 the difference in the price paid for gas by inter- and intrastate pipelines should be small.

Second, many producer-pipeline contracts set prices at oil-parity levels following decontrol. Although the effects of contract provisions are uncertain, they could cause large increases in the price of gas once controls are lifted. Under "Price Decontrol In 1983," the "contract problem" could be particularly acute.

Third, some time may be required to correct past bidding practices of pipelines. By buying gas on a long-term basis to cover expected demand, pipelines may initially bid gas prices over market-clearing levels after decontrol.

NGPA DECONTROL MAY CAUSE HIGHER PRICES IN INTRASTATE MARKETS

The NGPA partial decontrol of gas prices in 1985 has the potential to make intrastate buyers pay significantly more for their gas than interstate buyers. This is sometimes referred to as the "cushion problem."

The NGPA, coupled with the Natural Gas Act (NGA), has several provisions which could result in lower prices in the interstate market. Many types of new interstate gas, for instance, remain under price controls even after 1985. Examples include certain types of developmental wells, and all new (but not deep) gas found on older Outer Continental Shelf (OCS) leases. In addition, all old interstate gas is controlled until exhausted. By contrast, in 1985 the NGPA not only decontrols all new intrastate gas, but it also decontrols virtually all old intrastate gas in rollover contracts (an expired contract that has been renegotiated) and some old intrastate gas in original contracts. This disparity could mean that although over half of the interstate pipelines' gas remains controlled in 1985, intrastate pipelines would have less than thirty percent of their gas under controls. A second factor which favors interstate pipelines is that old interstate gas is, on average, only half as expensive as old intrastate gas. The difference occurs because old interstate gas is specifically regulated under the "just and reasonable" provisions of the original Natural Gas Act.

Because they have access to low-cost gas supplies, interstate pipelines can pay high prices for deregulated gas without raising the prices they charge to unmarketable levels. Intrastate buyers, however, do not have this cushion of cheaper gas and must bear the high price of deregulated gas supplies on all their sales. If all prices were deregulated, the cushion would not exist and interstate gas pipelines could not afford to pay more than market-clearing levels for deregulated gas. Such prices would then be lower and intrastate customers, in turn, would not have to pay so much for their gas.

We explored some implications of the disparity by estimating inter- and intrastate prices in 1985. In that year, under NGPA interstate pipelines would pay roughly 5 percent less for their gas than they would, were there no difference, between the treatment of intra/interstate gas. Intrastate pipelines would pay about 17 percent more. National average prices would be 1 percent higher as well because the high wellhead prices encounter less market resistance in intrastate markets. The differential does not last long. As old wells are depleted the cushion of low-price gas disappears. By 1990, there is only an 8 percent difference between intra- and interstate markets.

Using different, and perhaps more realistic, assumptions indicates a smaller differential. In our alternative case the interstate pipelines by 1985 pick up 1 Tcf of demand from what previously were intrastate customers because of their cheaper gas supplies. However, interstate pipeline investments in Synthetic Natural Gas (SNG), Liquefied Natural Gas (LNG), and imports burden them with another Tcf of high-cost supplemental supplies. In that scenario the differential is smaller. Interstate pipelines pay 3 percent less than the national average. Intrastate markets pay 10 percent more. As old gas runs out, both markets converge.

Solutions to intrastate market problems have been proposed. They range from opening up the Federal Outer Continental Shelf supplies to intrastate buyers, to raising old interstate gas prices, to total decontrol. Total decontrol, however has nationwide implications for gas supply and demand which are equally significant. Adjusting NGPA by raising old interstate gas prices would, in our first case above, cut the intra/interstate differential by half. Under the alternative case scenario, intrastate gas would in fact be slightly cheaper than interstate gas because of the latter's high cost supplemental supplies.

Based on our analyses, we believe that some price differential against intrastate buyers is likely but temporary. This disparity could be as high as 23 percent in 1985 (or higher under the high oil price scenario). Alternative assumptions or the explicit adjustment of old interstate prices would reduce this disparity substantially. The disparity shrinks by half over the next five years as old interstate gas is depleted.

In evaluating the extent of the intrastate market's plight, some other factors are worth keeping in mind as well. Costs to consumers on average, are likely to be as low or lower in intrastate markets even after decontrol because of generally lower transmission costs. Certain intrastate markets may also escape the problem entirely. Those in the region from West Texas through South Kansas appear to have gas prices which compare very favorably with even the better endowed interstate pipelines. Finally, similar disparities may arise between different interstate gas pipelines because of their different endowments of old gas. At present, however, the domestic portion of city-gate (price paid by local distribution companies for domestically produced natural gas) costs for each of the twenty largest pipelines is within 16 percent of the combined average.

PIPELINE CONTRACT PROVISIONS COULD INCREASE GAS PRICES UPON DECONTROL

Gas prices could rise substantially over market-clearing levels because of existing producer-pipeline contracts. Contracts, generally of long duration (15 to 20 years) are the basis on which producers sell gas to pipelines. Such contracts specify the terms of exchange, including prices, quantities, and mutual obligations. As long as price controls are in effect, the maximum price of such gas is limited to what the law allows. At the same time, though, most existing contracts specify the price that pipelines pay producers once controls end. The problem for gas users is that many of these contracts would, in effect, raise some gas prices to oil-parity--more than twice as high as what we see as market levels. Because it is not known how much gas will be priced that high, it is unclear by how much overall gas prices would exceed market levels. Following are some possible effects of the contract problem on the gas market. 1/

1/Additional information on the effects of contracts is contained in a forthcoming GAO report which examines issues concerning natural gas producer--pipeline contracts" and an EIA report entitled "Natural Gas Producer/Purchaser Contracts and Their Potential Impacts on the Natural Gas Market (DOE/EIA-0330: June, 1982). The latter report is the reference for contract data cited here.

Potential impacts
under NGPA decontrol 1/

The essence of the contract problem under the NGPA is that most (87 percent) of the interstate gas to be deregulated in 1985 is governed by contracts with deregulation provisions. Most (84 percent) of the contracts with deregulation provisions contain "most favored nation" clauses pledging pipelines to pay a price equal to the highest price paid for comparable gas in the area. The fly-up problem arises because a small but significant percentage (7 percent) of these contracts mandate pipelines upon decontrol to pay oil-parity prices for gas typically 110 percent of distillate fuel oil. The high prices on oil-parity gas, in turn, could raise prices of gas flowing under the large number of contracts with "most favored nation" clauses in them. The fear is that within months, virtually all contracts with "most favored nation" clauses would mandate oil-parity prices and result in retail natural gas prices considerably above those of alternative fuels.

While the prospect sketched above is plausible, the actual impact of such contracts on interstate prices under the NGPA is uncertain. Market-out clauses in many gas contracts could be a significant mitigating factor. Such provisions allow a pipeline to cancel its contract if it determines that the price called for renders its gas unmarketable. Market-out clauses cover 25 percent of interstate gas subject to deregulation in 1985, 42 percent of all interstate gas now deregulated, and over half of all gas placed under contract in 1980 (no later data exists). This trend suggests higher percentages of market-out clauses in the future--especially considering the recent buyer's market for gas and the universal awareness of the potential for contract-induced fly-up.

The various clauses, taken together, suggest certain plausible limits on how the contract problem will affect overall interstate gas prices under the NGPA. One important aspect of existing contracts (e.g., pre-1981) for gas no longer regulated after 1985 is that 60 percent of that gas would be priced at oil-parity if these contracts are carried out as written. EIA data suggest that 2/

--10 percent of all deregulated gas is not covered by deregulation clauses,

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1/Appendix I provides a graphical representation of the potential impacts of contracts under NGPA.

2/Less precision is used in these statistics because of statistical variances in the data and the difficulty of determining the presence of multiple clauses from EIA's tables.

--10 percent of all gas, though covered by deregulation clauses, is not covered by most-favored-nation or oil-parity clauses, and

--a further 20 percent, although subject to both clauses, is also covered by market-out clauses.

A second aspect is that roughly half of the interstate gas unregulated in 1985 will be covered by new (e.g., 1981 and later) contracts--ones more likely to contain market-out clauses. Finally, the interstate cushion of old gas can be expected to absorb much of the higher cost associated with oil-parity contracts.

One plausible assessment is that the contract problem would increase interstate gas prices only 10 percent over market levels. 1/ This is because in 1985 roughly half of all interstate gas would still be regulated, 20 percent would sell at oil-parity, and 30 percent at market levels. The 10 percent increase would result from averaging these three categories of gas. Specifically, the "old gas" cushion could absorb around two-thirds of the high-cost gas, and the market-priced gas would absorb another 10 percent. This, however, represents a national average--significant regional disparities between pipelines could be expected.

It is also possible to imagine a higher price scenario--one assuming fewer (60 vs. 80 percent) market-out clauses in new contracts, less use (60 percent) of those that exist and oil-parity pricing for many (50 percent) of the contracts with redetermination clauses but not most-favored-nation provisions. Under these assumptions, over a third of all interstate gas supplies in 1985 would be sold at oil-parity levels, with the interstate gas cushion absorbing only 40 percent of the high-cost gas. Overall prices would then rise to roughly 30 percent over market levels.

The scenarios above assume that current contracts are honored as written. At least two analysts argue that "the price of gas . . . will determine which contracts are honored, which will be renegotiated and which will be repudiated with

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1/The assumptions underlying this calculation include the full use of market-out clauses, that sixty percent of all deregulated gas in 1985 is from post-1980 wells (with a quarter of these wells covered by pre-1981 contracts), that eighty percent of all new contracts have market-out clauses, that gas prices--unless otherwise regulated or mandated by contract--go to market levels as determined in Chapter 2, and that all contracts are honored as now written.

impunity." 1/ Recognizing this possibility, producers may accede to contract renegotiation with the pipelines, even if their own contracts mandate high prices and mandatory minimum takes. Another reason why the fly-up may be lower is based on EIA's finding that only 3 percent of the interstate gas volumes scheduled to be deregulated in 1985 have oil-parity provisions without market-outs. If some percentage of these is renegotiated, the impact of contracts with oil-parity clauses on those with "most-favored-nation" provisions could be reduced--thus limiting the total effect of the contract-induced fly-up. 2/

In sum, our best assessment is that the contract problem may have no appreciable effect or could instead increase interstate gas prices 30 or 80 cents/per million Btu (MMBtu) over market-clearing levels depending on the assumptions made about contract renegotiation and market-out clauses. In contrast, EIA's estimate is that the projected impact of contract clauses in 1985 would be to increase prices by $ .21/ MMBtu, $ .44/MMBtu, or $ .84/MMBtu in the low, mid, and high case respectively. Their conclusions are based on a much smaller amount of deregulated

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1/Arlon R. Tussing and Connie C. Barlow, "The Rise and Fall of Regulation in the Natural Gas Industry," Institute of Social Economic Research, University of Alaska and ARTA, Inc., Nov. 13, 1981.

2/The effect of the contract problem on intrastate pipelines is even more uncertain. Intrastate markets have less of a price cushion and more of their gas will be deregulated. However, less than half (39 percent) of all deregulated intrastate gas is covered by deregulation provisions. Most new intrastate developmental gas is covered by contracts without most-favored-nation clauses, and new intrastate gas is half again more likely than interstate gas to be covered by market-out clauses. As a result, EIA data suggest that only 15 percent of the intrastate gas subject to deregulation has deregulation provisions, "mostfavored-nation" (or oil-parity) clauses and no market-outs. A comparable percentage have deregulation clauses which may increase prices after decontrol but not as high as oil-parity levels (EIA data is not conclusive). It is also noteworthy that EIA's 600 plus sample of contracts found no intrastate oil-parity contracts without market-out clauses. To the extent that sources of intrastate gas are geographically concentrated in certain areas, many intrastate contracts with "most-favored-nation" clauses may not be triggered to oil-parity levels. Furthermore, intrastate pipelines also benefit directly from any reduction in the interstate cushion because it limits what interstate pipelines can bid for old intrastate and newly discovered gas. Finally, intrastate contract problems may be addressed by local legislation or regulation in the absence of any Federal action.

gas in 1985, a somewhat higher percentage of such gas sold at oil-parity and no consideration of the old gas cushion. While AGA's mid-range Spring 1982 forecast does not specifically produce an estimate of the contract-induced fly-up in 1985 (as opposed to market-induced fly-up) our interpretation of their data suggests it is approximately, $ .60/MMBtu.

Potential impacts of total decontrol

Under "Price Decontrol In 1983," the contract-induced fly-up of prices is likely to be more widespread than under NGPA decontrol. In fact, all the major differences between total and partial decontrol work in this direction. The old-gas cushion would largely disappear, sharply reducing the amount of oil-parity pricing that could be absorbed. Although only two-thirds of the old 1/ gas is covered by deregulation clauses, over 90 percent of those that are covered also contain most-favored-nation clauses, while fewer than 7 percent have market-out clauses.

The same assumptions which suggested that NGPA decontrol would price gas ten percent over those levels reported in Chapter 2 also suggest that "Price Decontrol In 1983" would price gas sixty percent higher. The high-price scenario which implies 30 percent over-pricing with NGPA implies 80 percent overpricing with "Price Decontrol In 1983." By the same token, contract renegotiation can limit the contract problem but it requires a considerably higher percentage of cancelled contract terms to eliminate it completely. Similarly, the possibility of eliminating the "critical mass" of oil-parity contracts necessary to trigger "most-favored-nation" clauses is confounded by the larger number of old oil-parity contracts without market-out clauses.

Addressing the contracts problem-- several possible approaches

Proposals for defusing any contract-induced fly-up include: letting the pipelines work things out, FERC administrative action, and various legislative proposals. Regardless of what the Government does, though, the pipelines themselves could take certain actions which would help in defusing their own contract problems. Insistence on market-out clauses in future contracts, invoking them when and where necessary, pressing for renegotiation, or threatening litigation are all steps which could reduce their problems. Many of the differences between our plausible

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1/Including newly discovered gas on old Outer Continental Shelf leases, shallow developmental gas, and developmental gas on land dedicated to interstate commerce.

assessment (prices 10 percent over market-clearing levels) and the higher price scenario (30 percent) are governed by what the pipelines do from here on.

To the extent that Government may choose to intervene, FERC may be the focus for certain remedies. FERC's Chairman has stated that it may be compelled to act if contract provisions pose a serious risk of a price spike in 1985. Suggestions have included limiting pipelines' ability to pass on certain costs from high-price contracts and take-or-pay obligations to authorizing higher prices on regulated gas if producers renegotiate equivalent quantities of oil-parity contracts. FERC's monitoring and response capabilities are two issues of importance which we did not address during our analysis.

Legislative remedies have also been suggested, particularly in the context of total decontrol (whose enactment would otherwise make some contract fly-up very likely). These include voiding deregulation clauses, putting a price cap on oil-reference clauses, limiting the impact of oil-reference clauses on most-favored nation clauses, and limiting the scope of take-or-pay obligations.

Even if nothing is done legislatively, the impact of the contracts problem is likely to diminish after 1985, under partial or total decontrol, provided that future pipeline-producer contracts establish some means by which prices can adequately respond to prevailing market forces. The amount of old gas covered by high-price deregulation clauses is likely to diminish over time just as the amount of old regulated gas will.

PIPELINE BIDDING MAY PUSH PRICES OVER MARKET-CLEARING LEVELS

The possibility that bid prices overshoot (or undershoot) ultimate market-clearing levels exists in all industries, particularly those just released from price controls. In other industries, however, market disequilibrium does not persist; competitive pressures quickly guide markets to the level defined by the intersection of supply and demand.

Gas markets, though, may take a longer time to reach this equilibrium point. One reason is that pipelines buy gas on a long-term basis. This creates a strong momentum behind expected prices which may be too high. Gas contracts, as noted above, are one reason this can happen. Supplemental gas supplies, with their associated commitments of pipeline capital, are another.

Upward pressure on price may also arise from a lack of competition among interstate pipelines. Interpipeline competition, of the form which holds prices down in other industries, does exist but is limited. A significant fraction of all gas consumers depends on only one domestic gas pipeline. Those distributors with access to more than one pipeline are limited by the capacity constraints of their pipeline suppliers--particularly during the heating season. The lack of interpipeline competition explains why pipelines are regulated. Such regulation can prevent excess pipeline profits, but would not necessarily prevent pipelines from paying above current market clearing prices for natural gas.

Pipelines may also be reluctant to turn away gas supplies until they are very certain of their ability to cover demand at least several years into the future. If all pipelines bid for enough gas to achieve a safety margin, gas prices are likely to exceed market-clearing levels. Until gas prices under decontrol are better established, pipelines may logically want greater than a 50-50 probability that their supplies are adequate. This attitude places a premium on adequate supply and thus acts to raise gas prices.

All this considered, gas prices may initially overshoot market-clearing levels after decontrol. Industrial gas prices in interstate markets could temporarily rise up to levels significantly higher than residual oil. What happens next depends on how much demand is lowered by this increase. If demand is especially robust, excess gas supplies will be small enough to be manageable and gas prices will not retreat. Weak demand and lowered sales, however, would lead some pipelines to reevaluate their bidding behavior. Prices would drift down in real terms over a period of months to years until demand rises and excess supplies decline to manageable levels.

CHAPTER 5

SUMMARY OF MAJOR FINDINGS AND OBSERVATIONS

Passage of the NGPA in 1978, capping years of debate, was expected to settle the issue of natural gas pricing. Prices for newly discovered gas would rise to parity with oil by 1985, whereupon they would be released from regulation. Although old gas prices would remain controlled, depletion would steadily reduce their influence. The gas market would thus make a smooth transition to decontrol.

The NGPA, however, did not anticipate that oil prices would more than double by 1980, leaving gas prices on a trajectory falling far short of oil prices. Observers feared that gas prices would then jump sharply upwards in 1985 when new gas was decontrolled, threatening market disruption and renewing pressure for the reimposition of price controls. Among other potential NGPA problems were price escalation clauses being written into producer-pipeline contracts, which threatened to send gas prices to unrealistically high levels upon decontrol, and the possibility of concentrated shortages in the intrastate market due to the NGPA's preferential treatment of interstate gas.

Our analysis examined the potential gas market problems under the NGPA. It compared current law to alternative proposals which were designed to address these problems.

We analyzed NGPA and four alternatives to it. One, NGPA Extended, would continue NGPA price controls through 1990. Another, NGPA Adjusted, would raise certain gas prices, notably for old interstate gas found between 10 and 15 thousand feet (following suggestions of FERC's Chairman). Two others would decontrol all wellhead gas prices. Phased Price Decontrol would do so over a two-year period by increasing gas prices to 70 percent of crude oil prices. Price Decontrol In 1983 would do so at once in 1983.

Several points should be kept in mind when considering the information presented here. First, the economic impacts of each scenario result from the interaction of supply and demand. We analyzed institutional factors, which could affect wellhead prices beyond economic causes separately. The impacts of these factors were discussed in Chapter 4. In summarizing our conclusions here, however, we attempt to integrate and the institutional factors and their potential impacts.

Second, our economic analysis was based on numerous assumptions about energy and economic variables. Although we feel that these assumptions are reasonable, they do inject some uncertainty in our results. Thus, where appropriate, we report the sensitivity of our results to changes in key assumptions.

Finally, the purpose of this report is to provide information on the energy and economic impacts of current and alternative natural gas pricing policies. Given the level of uncertainty regarding some issues and the closeness of results between scenarios, no specific policy stands out as being unequivocally superior. Therefore, rather than making specific policy recommendations, we chose to lay out the pros and cons surrounding each alternative. We believe this will provide the Congress with more useful information to make decisions regarding natural gas policy.

Presented below is a summary for each scenario of the major energy and economic impacts estimated by our model followed by a discussion of potential institutional issues and an overall assessment of our results.

ENERGY AND ECONOMIC IMPACTS

Our model indicates that market forces alone would not make a substantial difference between scenarios in the production and price of natural gas or in producer and consumer revenues. Differences in impacts are largely a question of timing and occur mainly between "NGPA" and "Price Decontrol In 1983."

Production and prices

Our analysis revealed that under "NGPA" market forces will result in natural gas production and average wellhead prices which are very close to those resulting from "Price Decontrol In 1983." Thus, there is no economic justification for a substantial fly-up in average wellhead prices. Between 1982 and 1985, natural gas production and consumption under "NGPA" would be within 2 percent of that under "Price Decontrol In 1983." At the same time, differences in prices between "NGPA" and "Price Decontrol In 1983" converge and disappear by 1985. "NGPA" prices are 6 percent lower than "Price Decontrol In 1983" prices in 1983, 5 percent lower in 1984 and 3 percent lower by 1985. Prices under NGPA increase only 13 percent upon decontrol in 1985, compared to a jump of 18 percent under "Price Decontrol In 1983." Although prices under "Price Decontrol In 1983" would be somewhat higher in 1983 and 1984, the total increase through 1985 is comparable. "NGPA" and "Price Decontrol In 1983" result in a 38 and 42 percent real increase in average wellhead prices between 1982 and 1985 respectively. In short, "NGPA" provides a smoother path to decontrol and results in slightly lower prices throughout the 1980s.

These results are sensitive, however, to future oil price assumptions. Under higher oil price assumptions, average wellhead prices under "NGPA" increase 37 percent upon decontrol in 1985--compared to 13 percent in our base case. The sharp rise in prices under "NGPA" occurs because NGPA price ceilngs result in supply shortages in 1983 and 1984 when oil prices are high. While "Price Decontrol In 1983" results in substantially higher wellhead prices in 1983 and 1984 (14 and 21 percent respectively), the 37 percent fly-up under the "NGPA" eliminates the difference by 1985, and prices in this case are 2 percent higher than under "Price Decontrol In 1983."

Our results are less sensitive to lower economic growth assumptions. Lower growth lessens the price increase upon decontrol under both scenarios. In our low-growth case, "Price Decontrol In 1983" results in 1985 wellhead prices which are 9 percent higher than under "NGPA"--versus 3 percent in our base case.

Under all assumptions, "Phased Price Decontrol" and "NGPA Adjusted" lead to average wellhead prices above market-clearing levels as early as 1983. Consequently, the benefits of following either of these policies seem questionable.

Finally, "NGPA Extended" will reduce supply and could result in some curtailments after 1985.

Consumer and producer impacts

Consumer and producer impacts resulting from market forces alone are also similar under "NGPA" and "Price Decontrol In 1983." Both raise prices through the decade. "Price Decontrol In 1983" does so slightly sooner and, in the process, transfers $8 billion more than with NGPA (in current dollars before taxes) from consumers to producers between 1983 and 1985. Residential prices, for instance, are 3 percent higher under "Price Decontrol In 1983;" producer revenues are 5 percent higher.

INSTITUTIONAL FACTORS

The above results represent the influence of economic forces only. Certain institutional factors, notably the producer/pipeline contract problem and the old gas "cushion" problem may alter certain key aspects of the natural gas market.

The Contract Problem

Producer-pipeline contracts now in place constitute the main institutional force behind a price fly-up in 1985. A high percentage of interstate gas to be decontrolled in 1985 is governed by contracts which specify oil-parity prices, either directly or (by reference to other contracts) indirectly. Our assessment of the likely impact, qualified by many unknowns, is that adherence to such contracts, as now written, would raise interstate gas prices from 10 to 30 percent over market-clearing levels in 1985. The actual amount would depend on how vigorously pipelines insist on market-out clauses in new contracts and how widely they are used. Contract renegotiation or repudiation would reduce this increase. Under "Price Decontrol In 1983," the contract problem could raise prices 60 to 80 percent over market-clearing levels

and a much higher percentage of contracts would have to be renegotiated or repudiated to eliminate the problem. To the extent that contracts pose a serious risk of a large price increase, the Federal Government could intervene, if warranted. FERC may act if a contract-induced fly-up seems likely in 1985, however, we did not address FERC's monitoring or response capabilities in this area. Legislative remedies have also been suggested, particularly in the context of "Price Decontrol In 1983" (whose enactment would otherwise make some contract fly-up very likely). These include voiding deregulation clauses, putting a price cap on oil-reference clauses, limiting the impact of oil-reference clauses on most-favored nation clauses, and limiting the scope of take-or-pay obligations.

The old gas cushion problem

Under NGPA, the partial decontrol of gas prices in 1985 has the potential to make intrastate gas buyers pay significantly more for their gas than interstate buyers. Our analysis indicates that some price differential against intrastate buyers is likely to exist under the NGPA due to continued controls on old gas. This disparity could be as high as 23 percent in 1985. However, it shrinks rapidly as old interstate gas is depleted. The cushion problem is greatly reduced under "NGPA Adjusted" and disappears under "Price Decontrol In 1983."

COMBINED ECONOMIC AND INSTITUTIONAL IMPACTS

Table 4 presents the combined impacts on wellhead prices from both economic or market forces and contract provisions. As the table indicates, in 1985, under our most likely case, "NGPA" could lead to a total price fly-up ranging from 13 to 47 percent with the most likely being about 24 percent. Market forces account for 13 percent with the rest being contract-induced. Similarly, under "Price Decontrol In 1983," the fly-up in 1983 could range anywhere from 18 to 110 percent with the most likely being about 88 percent. In this case, 18 percent would be market-related and the remainder due to contract provisions. The potential fly-up is therefore much larger under "Price Decontrol In 1983." However, there is substantial uncertainty surrounding the future impacts of contracts as reflected in the wide ranges of the potential fly-ups reported here.

CONCLUSIONS

The future impacts of alternative policies are inherently uncertain, but a good case can be made against three of the alternatives discussed--"Phased Price Decontrol," "NGPA Adjusted," and "NGPA Extended." The first two set ceiling prices higher than necessary to clear the market and thus introduce needless uncertainty. "NGPA Extended" can also be faulted since, according to our model, it would create shortages in 1985 and thereafter.

Both "NGPA" and "Price Decontrol In 1983" are superior to these other alternatives.

The choice between "NGPA" and "Price Decontrol In 1983," however, is not clear. Because the effects of contracts are

Table 4

Combined Economic and Institutional

Impacts on Natural Gas Prices
(percent change)

	Price decontrol 1983	NGPA 1985
Economic		
Most likely	18	13
High oil	26	37
Contracts		
Most likely	60	10
Maximum	80	30
Minimum	0	0
Total 1/		
Most likely	88	24
Maximum	110	47
Minimum	18	13

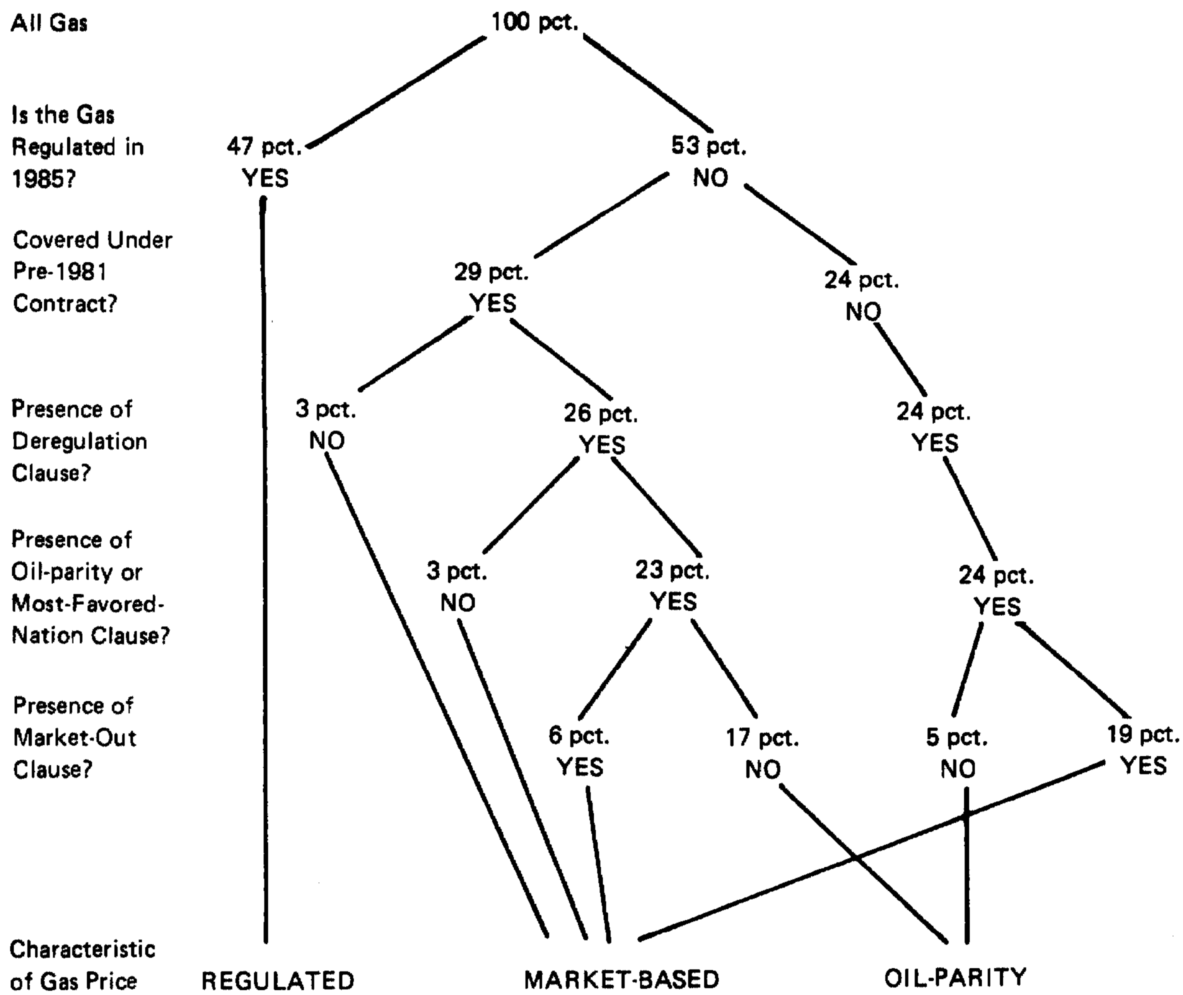
1/Sum of most likely economic increase and contract fly-up.

uncertain and because the results of our economic analysis of "Price Decontrol In 1983" and "NGPA" scenarios are so close, neither of these two options stands out as being unequivocally superior. "Price Decontrol In 1983" promises to alleviate many of the disadvantages suffered by intrastate markets' inability to compete with interstate pipelines for gas. It also increases economic efficiency somewhat by promoting greater conservation, more optimal fuel choices, and least-cost gas supplies. The "NGPA" offers a smoother increase to decontrol levels and slightly lower consumer prices overall. The contract problem is also more likely to be diffused under the "NGPA" than under "Price Decontrol In 1983."

In essence, when economics and market forces alone are considered, there appears to be very little difference between either option. When the admittedly less clear contract and institutional factors are also considered, however, the potential "fly-up" problem is greater under "Price Decontrol In 1983," while the "cushion" problem exists only under "NGPA."

These arguments make it obvious that there is no clear advantage to either "NGPA" or "Price Decontrol In 1983." Both options have positive and negative aspects and neither stands out clearly as the better choice. Therefore, GAO is not convinced that compelling reasons exist to attempt a change in NGPA's present course.

The Effect of the Contracts Problem on Average Interstate Prices in 1985 NGPA: Plausible Scenario



Price in $1980/MMBtu	1.70	2.85	6.60
Pct. of Gas	47	31	22

Average Price = $3.14/MMBtu or 10 percent higher than the NGPA market-clearing level of $2.85/MMBtu.

Note: These numbers are estimates. Double-digit accuracy is used here to minimize cumulative rounding errors, and does not contradict single-digit accuracy statements in the text.

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Report To The Subcommittee On Environment, Energy And Natural Resources, House Committee On Government Operations

OF THE UNITED STATES

An Analysis Of Natural Gas Pricing Policy Alternatives

Volume II Of 2 Volumes (Supply--Demand Methodology)

Several alternatives have been proposed to the Natural Gas Policy Act, which established a schedule for decontrol of natural gas prices. GAO examined four proposals to see how they compared in their effects on gas prices and supplies.

This report summarizes the results of GAO's analysis and discusses the advantages and disadvantages of the two more attractive options--continuing the provisions of the present law and total decontrol of natural gas wellhead prices in 1983.

GAO points out that should the decision be made to decontrol natural gas prices in 1983, the issue of what to do with existing contracts--which is the most serious problem under decontrol--will have to be addressed.

UNITED STATES GENERAL ACCOUNTING OFFICE

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Volume II

Technical Report

CHAPTER 1

NATURAL GAS SUPPLY MODEL

METHODOLOGY

In order to anticipate the energy and economic effects of alternative natural gas regulation policies, it is necessary to model the effect of price changes on natural gas supply. Building on earlier work by MacAvoy and Pyndick (1973), Erickson and Spann (1971), Khazzoom (1971), the American Gas Association (1973), and the Department of Energy (1979), we built a model of natural gas supply which incorporates a realistically complex lag structure and complex dynamics while maintaining a simple theoretical framework and manageable size. In section 2 we present an overview of the model and show how price changes are expected to affect activity in the natural gas supply sector. Section 3 contains a more detailed discussion of the model and presents the actual equations. The fourth section presents the model's simulation of the historical record for purposes of model verification. Finally, in section 5 we describe how our model was applied to the analysis of natural gas decontrol scenarios.

OVERVIEW OF THE MODEL

The logic of the model is as follows: A rise in the price of natural gas causes an increase in two kinds of exploratory drilling: new field wildcatting and old field wildcatting. New field wildcat gas wells are drilled in areas which have never been drilled before. Old field wildcat wells, commonly known as "new pool" wildcats, are exploratory wells drilled in existing fields but which are drilled at deeper depths or in hitherto untested areas within the field. The amount of gas actually discovered as a result of this drilling is the product of the number of wells drilled and the average size of discovery per well. The average discovery size, in turn, is a function of the price of natural gas since it represents the results of risks taken by the drilling companies in anticipation of a certain rate of return. At each point in time drillers have the choice of drilling relatively safe prospects which are unlikely to show a large discovery size and relatively risky prospects which can nevertheless result in large discoveries. The influence of price in determining average discovery size is an empirical question since the influence of price can theoretically be in either direction. (A higher price can encourage more intensive drilling of safe prospects, leading to a small average discovery size, or to more drilling in high-risk areas leading to a larger discovery size.) Total discoveries, the product of average discovery size and the number of exploratory wells, cause total reserves to increase. Extensions of existing reservoirs also cause total reserves to increase. However, revisions of estimates of pool size as a result of further drilling can be either positive or negative.

Production out of existing reserves and additions to underground storage are subtractions from reserves. The purpose of this model is to explain the behavior of total reserves by analyzing and predicting the behavior of each of these determinates: exploratory drilling, average discovery size, extensions, revisions, production, and additions to underground storage.

We assume, for purposes of analyzing natural gas supply, that the wellhead price of natural gas is exogenous to the model as are the price of crude oil, the average cost of drilling, and the overall rate of inflation. The model variables, both endogenous and exogenous, are presented in Table 1.

At the heart of the model are two identities which define total reserves in each year and net additions to those reserves. In our notation,

(1) TOTRES=TOTRES(-1) + DTOTRES
(2) DTOTRES=DISN+XN+RN+DISA+XANDRA-QNG-DUS

where

TOTRES= total reserves of natural gas

TOTRES(-1)= total reserves, lagged one year

DTOTRES= net additions to total reserves

DISN= discoveries of nonassociated gas

XN= extensions of nonassociated gas

RN= revisions of nonassociated gas

DISA= discoveries of associated gas

XANDRA= extensions and revisions of associated gas

QNG= production of natural gas

DUS= net additions to underground storage.

Table 1

Model Variables

Endogenous Variables

OFWC:	number of old field wildcat gas wells
NFWC:	number of new field wildcat gas wells
WXT:	total number of wildcat wells
SDNNF:	average size of discoveries, non-associated gas, new fields
SDNOF:	average size of discoveries, non-associated gas, old fields
SDN:	average size of discovery, non-associated gas
XN:	extensions of nonassociated gas
DIS:	total discoveries
DISA:	discoveries of associated gas
DISN:	discoveries of non-associated gas
RN:	revisions of nonassociated gas
QNG:	production of natural gas
US:	stocks of underground storage of natural gas
INT:	interest rate
SR:	success ratio
DTOTRES:	net additions to total reserves
TOTRES:	total reserves of natural gas
RP:	reserve to production ratio
XANDRA:	extensions and revisions of associated gas

Exogenous Variables

PGAS:	average wellhead price of natural gas
ACWL:	average cost per well

Table I

(continued)

PGNP:	GNP deflator
DUM7072:	dummy variable for 1970-1972
POIL:	average wellhead price of crude oil
DUM70:	dummy variable for 1970
RPMIN:	minimum reserve-production ratio
DUM7379:	dummy variable for 1973 to 1979

XANDRA= extensions and revisions of associated gas

QNG= production of natural gas

DUS= net additions to underground storage

Associated gas is natural gas found in reservoirs containing oil. We treat associated gas separately because the incentives are different from those in nonassociated gas. Associated gas is often discovered as a byproduct of drilling for crude oil. Similarly, extensions and revisions of associated gas are primarily influenced by conditions in the market for crude oil. Since non-associated gas is drilled for its own sake, such drilling is influenced by conditions in the market for natural gas and is to some extent independent of the price of crude oil.

Each of the variables in equation (2) requires at least one behavioral equation in order to be determined.

Discoveries of nonassociated gas (DISN) are modelled by four behavioral equations. The first takes the number of new field wildcat wells drilled as a function of the real price of natural gas, the lagged real average cost per well, and a time trend.

$$(3) \quad \log(NFWC) = \underset{(4.83)}{25.06} + \underset{(4.01)}{0.73}\log(RPGAS) - \underset{(4.26)}{1.86}\log(RACWL(-1)) + \underset{(4.41)}{1.86}\,TIME$$

RSQ= .88 F= 27.24 DW= 2.53 N=15

where

NFWCT= number of new field wildcat gas wells

RPGAS= real average wellhead price of natural gas

RACWL(-1)= lagged real average cost per well

TIME= time trend.

The second equation is concerned with predicting the average size per well of a new field discovery. We hypothesize that the higher the price that wildcatters expect for natural gas discovered through exploratory drilling, the more likely they are to try to find large new reservoirs. We therefore expect a positive effect of wellhead price on average discovery size. However, we also expect negative effects associated with the average cost per well, and time (representing the fact large fields are likely to be found first so that as time passes it becomes progressively harder to find large new fields). We also find that the success ratio has a negative effect on average discovery size. As success in the past increases, there are fewer large reserves to discover, and average discovery size declines. Our estimated equation is

$$(4)\quad \log(SDNNF) = \underset{(4.21)}{39.41} + \underset{(3.85)}{2.01} \log(RPGAS(-1)) - \underset{(3.16)}{3.09} \log(RACWL(-1))$$

$$- \underset{(14.72)}{0.20}\, TIME - \underset{(2.19)}{1.04} \log(SR(-1))$$

RSQ= .98 F= 58.11 DW= 2.28 RHO= -.78 N= 13

where

SDNNF= size of discovery of nonassociated gas in new fields

SR(-1)= success ratio, lagged one period

RHO= estimated autocorrelation coefficient.

The equation predicting the number of old field (new pool) wildcat gas wells is similar to that predicting new field wells except that the real price of gas is not lagged (indicating that there may be a quicker response to price incentive here than in new field wildcats). Also, the time trend and success ratio were not found to be significant for this equation.

$$(5)\quad \log(OFWC) = \underset{(3.14)}{21.28} + \underset{(8.55)}{1.32} \log(RPGAS) - \underset{(2.74)}{1.60} \log(RACWL(-1))$$

RSQ= .91 F= 44.61 DW= 2.27 N= 12

where OFWC= old field wildcat gas wells.

The average size of discovery per well of old field wildcats is taken to be a function of the price of natural gas, the lagged average size of <u>new</u> field discoveries, and a dummy variable isolating some extremely large discoveries in 1970-1972.

$$(6)\quad \log(SDNOF) = \underset{(4.47)}{5.670} - \underset{(2.42)}{.33} \log(RPGAS) + \underset{(3.93)}{.394} \log(SDNNF(-1))$$

$$+ \underset{(12.3)}{1.09}\, DUM7072$$

RSQ= .97 F=48.56 DW= 1.63 RHO= -.33 N= 12

where

SDNOF= average size of discovery per well of old field wildcat wells

DUM7072= dummy variable for 1970-1972.

The negative sign on the real price of gas, together with the positive effect in the SDNNF equation (4), indicates that a rising wellhead price of natural gas encourages the search for large new finds, but also encourages the search for small new pools within existing fields. The positive coefficient on SDNNF(-1) indicates that large discoveries in new fields in the past tend to produce large new pool discoveries in the future.

These behavioral equations are connected by a group of three identities.

(7) DISNNF=SDNNF*NFWCT

(8) DISNOF=SDNOF*OFWCT

(9) DISN=DISNNF+DISNOF

where

DISNNF= discoveries of nonassociated new field reservoirs

DISNOF= discoveries of nonassociated new pool reservoirs

DISN= total discoveries of nonassociated gas.

Discovery of associated gas is treated in much less detail in this model because much of it is involved with the search for oil and we chose not to develop an oil exploration module for this exercise. We take total discoveries of associated gas to be a function of the price of gas relative to the price of oil, a dummy variable for 1970 (the year of the Prudhoe Bay reservoir), and discoveries of associated gas lagged one period.

$$\log(\mathrm{DISA}) = \underset{(15.04)}{14.78} - \underset{(2.37)}{.621} \log(\mathrm{RPGAS/RPOIL}) + \underset{(18.1)}{4.28}\ \mathrm{DUM70} \tag{10}$$

$$- \underset{(1.35)}{.073} \log(\mathrm{DISA}(-1))$$

RSQ= .98 F= 21.6 DW= 1.95 N= 13

where

DISA= total discoveries of associated gas

RPOIL= real price of crude oil

DUM70= dummy variable for 1970.

The negative sign on the price ratio indicated that a rise in the price of natural gas will cause discoveries of associated gas to fall, presumably because more resources are diverted to the search for nonassociated gas. It also indicates that a rise in the price of crude oil, by encouraging the search for new oil, also causes discoveries of associated natural gas to increase. The negative (but insignificant) coefficient on lagged discoveries indicates that large discoveries of associated gas in one year do not imply large discoveries in following years.

Extensions of nonassociated gas are assumed to be influenced by the price of gas, lagged discoveries of nonassociated gas, lagged cost per well and a time trend.

$$\begin{aligned}(11)\quad \log(XN) = {} & \underset{(4.62)}{13.07} + \underset{(5.94)}{.725}\log(RPGASAVE) + \underset{(7.86)}{.582}\log(DISN(-1)) \\ & - \underset{(2.99)}{.679}\log(RACWL(-1)) - \underset{(5.82)}{.042}\,TIME\end{aligned}$$

RSQ= .93 F= 17.6 DW= 1.84 RHO= -.75 N= 13

where

XN= extensions of reserves of nonassociated gas

RPGASAVE= three year moving average of the real price of natural gas.

The moving average price of natural gas is interpreted to be a measure of expectations concerning the future price of gas. A rise in price or an increase in discoveries will have a positive effect on extensions while the cost of wells and the passage of time have negative effects.

Revisions of nonassociated gas are assumed to be a function of last period's change in total reserves of nonassociated gas, last period's overall level of reserves, and a time trend. Since reserves can be either positive or negative, we use a linear rather than a log-linear form for this equation.

$$\begin{aligned}(12)\quad RN = {} & \underset{(1.70)}{4.095E{+}07} + \underset{(1.92)}{.278}\,DTOTRESN(-1) - \underset{(1.67)}{.115}\,TOTRES(-1) \\ & - \underset{(1.38)}{893990}\,TIME\end{aligned}$$

RSQ= .63 F= 5.02 DW= 2.60 N= 18

where

RN= revisions of nonassociated gas

DTOTRESN= change in the total reserves of nonassociated gas

Extensions and revisions of associated gas are taken to be the historical ratio with respect to lagged total reserves.

(13) XANDRA = .004 * TOTRES(-1)

The decision to produce out of existing reserves is limited by the total reserves available and production capacity. Higher prices will encourage production along the "supply curve" for natural gas. Similarly, rising interest rates will also encourage production since most money earned from the sale of natural gas can be invested and earn the higher interest rates. Finally, production is sold mainly to pipelines on long term contracts, creating a great deal of inertia in the supply system. We incorporate this aspect of gas production into the model by means of a lagged endogenous variable. The production equation is

$$\text{(14)}\quad \log(QNG) = \underset{(2.54)}{-10.27} + \underset{(2.68)}{.161} \log(RPGASAVE) + \underset{(.90)}{.096} \log(INT) + \underset{(4.04)}{.674} \log(TOTRES(-1)) + \underset{(5.12)}{.793} \log(QNG(-1))$$

RSQ= .97 F= 114.6 DW= 2.22 N= 17

where

INT= interest rate (AAA bond rate).

These fourteen equations form the heart of the model, although there are a few "housekeeping" equations remaining. The first is an equation predicting the level of underground storage stocks:

$$\text{(15)}\quad \log(US) = \underset{(109.7)}{15.14} - \underset{(1.71)}{.106} \log(RPGAS) - \underset{(2.39)}{.084}\, DUM7379 + \underset{(5.22)}{.044}\, TIME$$

RSQ= .86 F= 19.13 DW= 1.89 N= 13

where

US= total amount of gas in underground storage

DUM7379= dummy variable for 1973-1979.

We must also forecast interest rates. We use the equation,

$$\text{(16)}\quad INT = \underset{(9.20)}{4.31} + \underset{(4.95)}{.289}\, INFL + \underset{(1.78)}{.122}\, INFL(-1) + \underset{(2.31)}{.145}\, INFL(-2)$$

RSQ= .95 F= 46.32 DW= 1.74 RHO= .60 N=15

where

INFL= ((PGNP-PGNP(-1))/PGNP(-1))*100

PGNP= GNP deflator.

With these equations and forecasts of the wellhead price of natural gas, the wellhead price of crude oil, and the GNP deflator, we can forecast natural gas supplies. 1/

For some forecasting purposes we add a constraint which sets the lower bound on the reserve to production ratio. A very low ratio of reserves to production implies that production out of existing reserves has been occurring at a very high rate. If production is too rapid then a reservoir's production capacity may be permanently reduced. There are, therefore, physical and customary limits below which the reserve to production ratio will not fall. The constraint is of the form:

(17) RP=IF (TOTRES/QNG) =RPMIN THEN RPMIN ELSE (TOTRES/QNG)

where

RP = reserve to production ration

RPMIN= minimum RP ratio.

If the constraint is effective (that is, if production implied by equation (14) above is too high relative to the level of total reserves), then production is determined by,

(18) QNG = TOTRES/RP.

This constraint is invoked for forecasts only, not our historical simulations, and requires the user to supply a value for RPMIN.

MODEL VERIFICATION AND HISTORICAL SIMULATION

Whatever credibility this model has derives from its ability to replicate previous experience. This ability derives from the model's theoretical specification and its statistical properties. The review of the estimated equations presented in the previous section revealed a preponderance of highly significant coefficients with correct signs and reasonable magnitudes. The RSQ range from a low of .63 (for equation (12): revisions of nonassociated gas) to .98 for equations (4) and (10), SDNNF and DISA. Each of the behavioral equations seems to be explaining the movement of the endogneous variables quite well.

Because of the long time lags that characterize the exploration, development and production processes in energy as well as the exogeneity of the controlled price, the model is assumed to be strictly recursive. This allows us to use the efficient,

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1/We also require a set of equations which take antilogs of the dependent variables in the log-linear equations and two equations which define the real price of gas and oil as the wellhead prices divided by the GNP deflator.

consistent and unbiased ordinary least squares technique to estimate the equations in the model, with an autocorrelation correction where necessary, and relieves us of concern with simultaneous equation bias and the inefficiency associated with the instrumental variables techniques necessitated by simultaneous equation problems. The model is characterized by a rich lag structure since seven out of eleven behavioral equations include lagged endogenous variables. The presence of these lags implies that the RSQ may not be good indicators of explanatory power since errors can accumulate from one period to the next.

In order to validate the model we simulated the historical period from 1967 to 1979, on which data the model is estimated. However, we used only estimated values of all endogenous variables in order to investigate the effects of error accumulation and to yield some notion of the model's ability to track actual experience. If the model explains the historical record accurately, we have some confidence in its ability to forecast future values of the endogenous variables.

The most important endogenous variables are total reserves of natural gas (TOTRES), the number of exploratory wells drilled (WCT), discoveries (DIS), production (QNG), and the reserve to production ratio (RP). The results of the historical simulation revealed that the model does only a fair job of simulating the highly volatile wildcat drilling series (WCT). This series is forecast separately for new field and old field wildcats (equations (3) and (5)) and added together. The model misses the large increases in 1970, 1973, 1976, and 1978. However, the model seems to recover in years subsequent to these and shows no evidence of error accumulation. There is some tendency to underpredict exploratory drilling with 8 out of the 13 years in the series showing negative errors. The negative errors also tend to be the largest errors, yielding a mean percentage error of -7.14 percent. The root mean square percentage error is 15.6 percent.

Discoveries of natural gas are also difficult to simulate since they can be quite volatile, doubling, for example, in 1974 and then falling to the second lowest value in the series two years later. 1/ The model tends to underpredict discoveries, in part because it tends to underpredict wildcat drilling. The mean percentage error is -11.0 percent and the root mean square percentage error is 21.3.

1/The huge increase in 1970 was due to the discovery of associated gas in Alaska and is captured in the model by a dummy variable for that year. Since we do not anticipate another discovery of this magnitude in the next decade, we keep this variable equal to zero for forecasting purposes.

Despite the difficulties associated with modelling wildcat drilling and the discovery process, our historical simulations revealed that the model tracks total reserves of natural gas quite well. The largest error is 2.1 percent, occurring early in the simulation (1968), and the overall root mean square percentage error is only 1.3 percent. However, there does seem to be a slight downward bias with the model underpredicting in all but one year and generating an overall negative mean percentage error. The fact that the largest errors occur early in the period creates some hope that the forecast errors will be correspondingly small.

The results of the historical simulation for the production series showed that the model simulates production quite well with a maximum error of -9 percent in 1973. The model underpredicts production in all but the first two years, yielding a mean percentage error of -3.1 percent. The root mean square percentage error is a respectable 4.5 percent. (This is somewhat better than the performance of the MacAvoy-Pyndick model reported in the 1973 Bell Journal which had a RMS percentage error of 6.6 in its historical simulation of production.)

The reserve to production ratio (RP) is a number that is a central concept in most treatments of the natural gas industry. In this model the RP ratio is determined as a result of separate calculations of total reserves (equation (1)) and production (equation (14)). Although the level of reserves is a significant determinant of production in equation (14), the price of gas, interest rates, and last period's production all act on the decision to produce. Thus, the RP ratio does not determine production as in some models but is itself determined by the model. The period from 1967 to 1979 is one of fairly constant decline in the reserve to production ratio, falling from 15.9 in 1967 to 9.8 in 1979. The historical simulations showed that the model tracks RP very well with an overall root mean square percentage error of 4.3 percent. There does seem to be a slight upward bias with an overall mean percentage error of +2.3 percent and positive errors in all but the first three years. 1/

Overall, the model seems to do an adequate job of simulating a highly volatile industry. The model does best simulating the behavior of the total reserve aggregate, production, and the RP ratio. It does less well in the less aggregated series such as exploratory well drilling, discoveries, and average discovery size. The model does remarkably well given the complex lags in the model

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1/As noted above, we allow the forecaster to set the minimum RP ratio so that simulations of future behavior of gas supply will not result in unrealistically low RP ratios. This constraint is not imposed for the historical simulation.

(and in the real world) and the fact that the model simulates all these aspects of natural gas supply while requiring only ten exogenous variables. The model tends to underpredict discoveries, drilling, reserves, and production. We therefore expect forecasts generated by this model to be on the low side. We do not expect the model to generate wildly optimistic scenarios.

SCENARIO ANALYSIS

In this section we lay out the approach used in modeling the impacts on natural gas supply of alternative natural gas decontrol scenarios. 1/ In later years, this exercise required combining forecasts obtained from our natural gas supply and demand models. (The demand model is described separately in appendix 2.) For each deregulation scenario the model was run in two phases, the first phase corresponding to earlier years with regulations in effect (1982-1984, except for total decontrol-1983) and the second phase representing decontrol. During the analysis average wellhead price was the only exogenous variable to change. Assumptions regarding other exogenous variables do not change across cases and are reported in table 2.

In phase one, we ran our supply model for each scenario based on estimates of the average wellhead price for a given year from 1982 through 1984 (1981-1982 for total decontrol-1983).

Table 2

Exogenous Variables (1982-90)

Year	PGNP	ACWL 1/	POIL 2/
1980	$1.77	22	34.00
1981	$1.94	31	34.00
1982	$2.09	33	33.60
1983	$2.29	35	36.20
1984	$2.41	41	38.80
1985	$2.58	47	41.50
1990	$3.59	80	66.30

1/$ well/Thousand.

2/Average refiner acquisition cost of crude oil.

The average wellhead price of gas under controls was estimated by determining the quantity of gas in each relevant NGPA category

1/The same approach was used for our base case, low demand, and high oil cases.

and then applying the proper price to such gas. Baseline prices and quantities were taken from the November 1981 compilation of PGA filings of the major interstate pipelines. These data were aggregated and classified by EIA and FERC at the request of GAO 1/. These interstate data became proxies for the national gas market.

Prices for future years were adjusted as follows:

--prices for new exploratory gas (section 102) rose 4 percent annually as per NGPA. Prices for old intrastate gas (section 105) and stripper (section 108) gas lagged somewhat behind section 102 gas rising 10 cents/MMBtu annually.

--prices for developmental gas (section 103) and deep gas (section 107) were held constant.

--prices for old interstate gas (section 104) rose 3 cents/MMBtu a year to reflect the faster depletion of very old gas and the slower depletion of gas discovered in the 1973-1978 period.

Quantities per category were adjusted as follows:

--the percentage share of exploratory gas (section 102) rises roughly four points a year through 1990.

--developmental gas quantities initially rise as fast as exploratory gas quantities but peak in the late 1980s at double levels recorded in November 1981.

--deep and supplemental gas quantities rise by slightly over .1 tcf/year through 1990.

--intrastate and stripper gas quantities combined decline by two percent a year initially increasing to five percent in the late 1980s.

--old interstate gas declines by 15 percent a year increasing to twenty percent by the late 1980s.

These increase and decline rates are comparable to similar forecasts made by EIA.

Under partial deregulation we project that all old interstate gas and a certain fraction of the new gas will continue to be regulated. The regulated fraction of new developmental gas under regulation represents gas on old OCS leases--15 percent of all new

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1/See the GAO report, "Pipeline Purchases of High-Cost Natural Gas: Extent and Contested Issues" (EMD-82-53).

exploratory gas in 1985 declining to 5 percent in 1990. The regulated fraction of developmental gas represents shallow gas (through 1987) and gas on acreage dedicated to interstate commerce under the NGPA--declining from 55 percent in 1985 to 25 percent after July 1, 1985 and to 10 percent in 1990. To calculate similar quantities for intrastate gas, we omitted all controlled new gas supplies (which are by definition dedicated to interstate commerce) and eliminated 30 percent of all old gas as well as gas being covered by rollover (section 106) contracts subject to deregulation after 1985.

Estimates of average and marginal prices under the NGPA adjusted and Phased Decontrol scenario were made in this context. For Phased Decontrol, we created a new NGPA category composed of gas discovered in 1983 and 1984. Such gas received a price per BTU equal to 70 percent of crude. Quantities were estimated by taking pre-calculated quantities of developmental and exploratory gas in 1983 and 1985 and then subtracting the 1982 figure for these categories less ten percent annual depletion. Prices for all other categories in 1983 and 1984 were assigned a weighted price averaging the NGPA price and a price equal to 70 percent of crude. For NGPA adjusted, old interstate gas (section 104) was assigned a price equal to $1.45/MMBtu plus an inflation factor (section 109 prices). In addition, a substantial fraction of all gas discovered from mid-1982 on was reclassified as near-deep gas (receiving 150 percent of section 103 prices) while a smaller fraction was redefined as neartight-gas (receiving 200 percent of section 103 prices).

Using our estimated average wellhead price paths for each scenario developed in the above manner as inputs into our supply model we were able to estimate the level of domestic natural gas supply, reserve additions, total reserves, etc. for each year and scenario from 1982-1984.

Phase two of our analysis represents the natural gas market response under both partial and total decontrol. It is at this point (1985) that we first report the market-clearing or equilibrium price and quantity as determined by the forces of supply and demand. For each year and scenario from 1985 to 1990 the market-clearing price and quantity were determined in three steps.

First, we made three runs of the supply model for the period 1981-1985. During these runs the average wellhead price for 1981 through 1984 equaled those under regulations (i.e., NGPA). The 1985 price varied from a low to a medium and high level. This resulted in three price/quantity points which when connected made up a supply curve for 1985. We then added to this supply curve our estimates of yearly supplemental gas supplies which include imports and unconventional domestic supplies shifting our 1985 supply curve to the right. (See Appendix I, pg. 64.) Our third step was to combine this supply curve with a 1985 demand curve developed from our natural gas demand model to arrive at an equilibrium free market price and quantity.

We repeated this procedure until we obtained an equilibrium point for each year from 1985 thru 1990. Tables 3 through 7 provide results from sample runs of our domestic natural gas supply model.

SUPPLEMENTAL GAS

Analysis of supplemental gas was separated into (1) gas imports, and (2) unconventional domestic sources of gas. Imported gas supplies include gas from Algeria (in the form of Liquefied Natural Gas (LNG)), Canada, and Mexico. We assume Alaskan supplies (which have been delayed to 1989 by pipeline financing and construction problems) will not be available by 1990. If Alaskan supplies begin prior to 1990, volumes will probably be small until the ANGTS system is fully operating.

Since the contract dispute between Algeria and the El Paso project in 1980, imports are shipped only to the Distrigas Project. We assume current deliveries of around 42 Bcf per year continue. Several other LNG projects are in the works and we assume they come on line between 1986 and 1990. Primarily, this is because the U.S. is not located advantageously compared to other competing markets for gas. As a result, the FOB price to the U.S. is assumed to be comparable to the price which could be realized by exporting countries selling the gas elsewhere. For example, the price of Algerian gas would be compared with its value to Western Europe. For Indonesian supplies, the competing market would be Japan. Once transportation costs are added (about $1/mmbtu) the landed price to the U.S. is expected to be above the price of distillate oil. We assume that while U.S. wellhead price controls are in effect price terms imposed by LNG exporting countries will not be acceptable. After natural gas is decontrolled we assume that by 1990 roughly half of previously supplied LNG volumes (prior to the El Paso-Algerian dispute) will be imported along with small quantities from Indonesia. Because current imports of LNG and U.S. LNG exports to Japan are about equal, we project flat net LNG imports to 1985.

Canada is currently the largest supplier of imported gas to the U.S. Present authorized export levels are roughly 1.3 Tcf annually. However, the U.S. only "takes" about 800 Bcf per year. There is general agreement that from a resource perspective, Canada could increase current authorized levels substantially. A GAO report, "Oil and Natural Gas from Alaska, Canada, and Mexico--Only Limited Help for U.S." finds that the National Energy Board (NEB) cites conservative estimates of established gas reserves at 71 Tcf for the end of 1979. Additionally, frontier areas were estimated at 14.5 Tcf. However, even with substantial reserves and a potentially large exportable surplus of gas, internal political policies will be of overriding consideration.

Given Canadian gas resources, export levels could be expected to continue easily at present levels or increase during the 1980s. We assumed, after talking with industry and government experts,

Table 3
NGPA[1]
(1982–90)

	PGAS	Q	TOTRES	DIS	DISN
1982	279.0	18,934,832	170,412,129	3,194,209	2,961,114.934
1983	323.0	18,235,841	164,121,507	3,646,311	3,417,238.239
1984	372.0	17,678,968	159,109,866	3,431,219	3,202,296.004
1985	491.0	17,210,883	154,897,232	3,720,957	3,513,391.261
1986	526.0	16,832,599	151,492,817	4,194,689	3,979,238.072
1987	564.0	16,491,492	148,422,905	4,106,058	3,885,674.124
1988	604.0	16,063,921	144,574,636	3,718,196	3,492,974.044
1989	648.0	15,488,637	139,396,852	3,385,829	3,148,439.802
1990	694.0	14,799,257	133,192,259	3,124,061	2,867,104.102

	SDNNF	SDNOF	SDN	WXT	NFWC	OFWC
1982	2,009.614	1,126.508	1,382.621	2,142	621	1,521
1983	2,497.523	1,144.639	1,542.759	2,215	652	1,563
1984	1,703.167	1,216.694	1,362.251	2,351	703	1,647
1985	1,835.321	976.729	1,223.309	2,872	825	2,047
1986	2,496.963	1,006.700	1,454.999	2,735	823	1,912
1987	2,207.587	1,136.345	1,473.548	2,637	830	1,807
1988	1,933.010	1,081.329	1,361.339	2,566	844	1,722
1989	1,681.642	1,023.606	1,249.070	2,521	864	1,657
1990	1,469.838	967.257	1,146.919	2,500	894	1,606

	RN	XN
1982	1,488,851	5,604,865
1983	1,587,568	6,225,927
1984	1,866,239	6,916,108
1985	1,867,234	6,899,199
1986	1,647,871	7,230,402
1987	1,353,481	7,630,651
1988	881,669	7,306,507
1989	183,152	6,457,385
1990	-526,393	5,749,968

1/ Quanity in million cubic feet, prices in cents per million BTU/Nominal.

Table 4
Price Decontrol In 1983 1/
(1982–90)

	PGAS	Q	TOTRES	DIS	DISN
1982	279.0	18,934,832	170,412,129	3,194,209	2,961,114.934
1983	310.0	18,216,639	163,948,654	3,532,823	3,297,828.623
1984	365.0	17,623,370	158,609,428	3,286,208	3,055,000.726
1985	426.0	17,053,702	153,482,449	3,222,139	2,995,595.264
1986	472.0	16,496,670	148,469,183	3,360,061	3,131,088.689
1987	522.0	15,957,813	143,619,493	3,323,927	3,093,721.055
1988	578.0	15,403,369	138,629,475	3,219,615	2,988,891.872
1989	640.0	14,819,320	133,372,992	3,132,547	2,893,742.905
1990	709.0	14,217,390	127,955,590	3,087,468	2,834,012.696

	SDNNF	SDNOF	SDN	WXT	NFWC	OFWC
1982	2,009.614	1,126.508	1,382.621	2,142	621	1,521
1983	2,497.523	1,160.336	1,560.628	2,113	633	1,481
1984	1,568.453	1,224.382	1,328.145	2,300	694	1,607
1985	1,766.705	991.150	1,227.471	2,440	744	1,697
1986	1,878.060	1,027.983	1,295.317	2,417	760	1,657
1987	1,776.465	1,042.255	1,280.687	2,416	784	1,631
1988	1,655.088	1,007.304	1,224.020	2,442	817	1,625
1989	1,539.587	966.926	1,164.088	2,486	856	1,630
1990	1,433.666	927.640	1,107.064	2,560	908	1,652

	RN	XN
1982	1,488,851	5,604,865
1983	1,587,568	6,171,644
1984	1,836,901	6,695,309
1985	1,827,975	6,445,525
1986	1,545,766	6,209,752
1987	1,224,271	6,222,500
1988	896,862	5,985,220
1989	499,673	5,647,734
1990	94,014	5,367,740

1/ Quanity in million cubic feet, prices in cents per million BTU/Nominal.

Table 5
NGPA Extended[1/]
(1982–90)

	PGAS	Q	TOTRES	DIS	DISN
1982	279.0	18,934,832	170,412,129	3,194,209	2,961,114.934
1983	323.0	18,235,841	164,121,507	3,646,311	3,417,238.239
1984	372.0	17,678,968	159,109,866	3,431,219	3,202,296.004
1985	433.0	17,149,815	154,347,526	3,371,071	3,146,646.051
1986	494.0	16,638,403	149,744,851	3,556,666	3,333,929.298
1987	561.0	16,163,023	145,466,483	3,679,465	3,458,889.036
1988	637.0	15,709,563	141,385,372	3,763,219	3,545,332.982
1989	707.0	15,254,063	137,285,875	3,788,593	3,563,165.721
1990	786.0	14,782,680	133,043,402	3,784,674	3,545,934.667

	SDNNF	SDNOF	SDN	WXT	NFWC	OFWC
1982	2,009.614	1,126.508	1,382.621	2,142	621	1,521
1983	2,497.523	1,144.639	1,542.759	2,215	652	1,563
1984	1,703.167	1,216.694	1,362.251	2,351	703	1,647
1985	1,835.321	1,018.298	1,265.587	2,486	753	1,734
1986	1,940.471	1,027.869	1,309.585	2,546	786	1,760
1987	1,946.443	1,030.827	1,319.667	2,621	827	1,794
1988	1,912.441	1,011.071	1,301.184	2,725	877	1,848
1989	1,870.997	990.278	1,281.886	2,780	920	1,859
1990	1,750.566	967.949	1,234.607	2,872	979	1,894

	RN	XN
1982	1,488,851	5,604,865
1983	1,587,568	6,225,927
1984	1,866,239	6,916,108
1985	1,867,234	6,717,381
1986	1,555,266	6,532,823
1987	1,201,979	6,641,331
1988	859,030	6,667,314
1989	459,254	6,608,273
1990	-47	6,483,469

1/ Quanity in million cubic feet, price in cents per million BTU/Nominal.

Table 6
NGPA Adjusted 1/
(1982—90)

	PGAS	Q	TOTRES	DIS	DISN
1982	306.0	18,976,614	170,788,229	3,432,338	3,212,244.297
1983	371.0	18,410,224	165,691,150	4,284,494	4,073,425.258
1984	422.0	18,072,222	162,649,485	4,323,410	4,110,460.635
1985	429.0	17,726,368	159,536,788	3,945,109	3,718,184.033
1986	474.0	17,245,792	155,211,399	3,598,880	3,370,536.468
1987	524.0	16,630,492	149,673,488	3,355,155	3,125,448.401
1988	579.0	15,934,318	143,407,802	3,239,821	3,009,308.485
1989	640.0	15,216,288	136,945,494	3,141,905	2,903,084.082
1990	708.0	14,505,290	130,546,529	3,086,299	2,832,621.965

	SDNNF	SDNOF	SDN	WXT	NFWC	OFWC
1982	2,009.614	1,092.529	1,348.285	2,382	664	1,718
1983	2,802.359	1,093.247	1,567.568	2,599	721	1,877
1984	2,248.796	1,220.966	1,512.649	2,717	771	1,946
1985	2,363.578	1,139.479	1,511.400	2,460	747	1,713
1986	1,904.683	1,151.119	1,397.695	2,429	763	1,666
1987	1,791.595	1,046.716	1,288.244	2,426	787	1,639
1988	1,667.832	1,010.093	1,229.989	2,447	818	1,629
1989	1,544.934	969.849	1,167.845	2,286	856	1,630
1990	1,433.666	929.341	1,108.259	2,556	907	1,649

	RN	XN
1982	1,488,851	5,732,317
1983	1,651,477	6,861,430
1984	2,033,201	8,218,438
1985	2 041 321	8,263,768
1986	1,464,107	7,467,031
1987	692,731	6,680,465
1988	55,408	6,038,925
1989	-368,617	5,679,933
1990	-625,466	5,391,531

1/ Quanity in million cubic feet, price in cents per million BTU/Nominal.

Table 7
Phased Price Decontrol 1/
(1982–90)

	PGAS	Q	TOTRES	DIS	DISN
1982	279.0	18,934,832	170,412,129	3,194,209	2,961,114.934
1983	388.0	18,329,883	164,968,026	4,210,977	4,006,565.567
1984	489.0	18,078,965	162,710,306	4,935,217	4,740,437.957
1985	378.0	17,835,956	160,523,236	4,195,466	3,948,365.068
1986	429.0	17,352,555	156,172,256	3,241,148	2,999,722.087
1987	487.0	16,601,879	149,415,764	2,777,474	2,538,057.726
1988	554.0	15,737,370	141,635,015	2,832,227	2,596,026.283
1989	629.0	14,924,888	134,322,758	2,902,633	2,661,658.619
1990	714.0	14,202,877	127,824,796	3,008,077	2,755,893.406

	SDNNF	SDNOF	SDN	WXT	NFWC	OFWC
1982	2,009.614	1,126.508	1,382.621	2,142	621	1,521
1983	2,497.523	1,077.127	1,463.809	2,737	745	1,992
1984	2,460.249	1,111.228	1,470.588	3,223	859	2,365
1985	3,176.400	1,231.089	1,853.427	2,130	682	1,449
1986	1,477.650	1,336.589	1,382.689	2,169	709	1,460
1987	1,466.715	970.482	1,136.137	2,234	746	1,488
1988	1,440.001	947.375	1,114.949	2,328	792	1,536
1989	1,414.037	920.658	1,091.669	2,438	845	1,593
1990	1,384.668	895.014	1,068.166	2,580	912	1,668

	RN	XN
1982	1,488,851	5,604,865
1983	1,587,568	6,494,719
1984	2,009,657	8,361,528
1985	2,253,407	9,005,269
1986	1,624,188	7,727,352
1987	577,676	6,106,499
1988	-260,591	5,032,655
1989	-603,804	5,001,395
1990	-583,021	5,006,927

1/ Quanity in million cubic feet, prices in cents per million BTU/Nominal.

that the Canadian Government will probably reconsider their present export policy sometime in 1982 and as a result make arrangements to increase authorized exports. Although an exact number is difficult to estimate, most individuals we talked with believe an increase to about 1.5 Tcf by the mid-1980s was reasonable. Actual quantities imported, on the other hand, will depend on the pricing strategy adopted by Canada. We assume that prior to wellhead price decontrol, Canada (and Mexico as discussed later) will sell gas at a border price equal to the current price (about $4.94 per MMBtu) adjusted for changes in world oil prices. Mexico is presently exporting about 109 Bcf of gas per year to the U.S. As with Canada, Mexico has a substantial resource base which should not prove to be a limiting factor in its export policy. At present, Mexico is making arrangements to increase its current export ceiling for natural gas. The extent of increase exports to the U.S. will be, as with Canada, dependent on internal government policies.

After talking with knowledgeable individuals, it appears likely, as we assume, that current export levels from Mexico will double. Nevertheless, these gas supplies will not be available for 12-18 months. This is because the U.S. pipeline has a capacity of only 300-350 mmcf per day which is used by current imports. Added pipeline capacity will, therefore, need to be constructed. In addition to construction requirements, we assume legal and environmental problems will delay the availability of this new Mexican gas until about 1985-86. Assumptions about Mexican pricing strategies are comparable to those discussed with regard to Canada. Present U.S. "takes" of Mexican natural gas supplies are high and are assumed, in the short run, to continue.

Unconventional domestic supplies of gas included tight gas, Devonian shale, coal seams and geopressured brine. Synthetic* supplies from coal gasification (in situ) and substitute natural gas (SNG) were also considered. Each of these gas resources was considered separately in the forecasting method in order to recognize and evaluate its special economic characteristics. Of unconventional gas supplies, only tight gas and Devonian shale are commercially produced. Small quantities of SNG are produced for base load and peaking needs and are assumed to continue. Because of the timeframe used in this report (1982-1990) and a variety of technical problems, we assumed that production of coal seams and geopressured brines is limited. Further, only small new supplies of Devonian shale gas are assumed to be available in our analysis.

Although in situ coal gasification is thought to have significant potential, a variety of technical questions must be answered before significant amounts of gas can be produced. We assume conservatively the operation of only a small demonstration plant by the early 1990s.

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*SNG is not a synthetic supply of gas.

Of all unconventional domestic sources of gas, only tight gas was estimated to increase at any notable rate during the 1982-1990 timeframe. Our base assumption is that current production of tight gas of .8 Tcf per year continues. From this base, supplies are projected to grow gradually under present incentive pricing (200% of section 103 prices). Because few companies actively explore for tight reservoirs, we assume much of new gas production over the next several years will result from drilling for conventional plays. That is, as profitable conventional finds become more scarce, exploration efforts will inevitably begin to produce a greater number of tight finds. Based on interviews, we do not foresee technology breakthroughs over the next several years that could substantially increase tight gas supplies. Overall growth, therefore, is assumed to be slow to moderate with a slight acceleration toward the end of the period.

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CHAPTER 2

NATURAL GAS DEMAND MODEL METHODOLOGY

Our analysis of alternative gas price decontrol scenarios required us to simulate the effect of different gas prices on the level of gas supply and demand. This chapter describes the methodology and structure of the model we employed to derive natural gas demand.

OVERVIEW OF THE MODEL

Our demand model is composed of submodels covering industrial fuel, industrial feedstocks, residential, commercial, power plant, and own-gas-use demand. A procedure similar to the following was used for each sector.

--Establish a baseline level of gas usage (1980) by subsector;

--Project growth rates by subsector;

--Calculate total energy usage by estimating gas usage per unit output;

--Subtract away alternative fuels (e.g., coal);

--Determine the oil and gas split.

The last three steps were estimated as a function of gas prices; oil to gas splits in particular were very price-sensitive.

These procedures, in turn, required two types of analyses. The first stage was data-intensive, both in terms of published information and also in terms of sub-sector estimates derived from published information. EIA data provided the basic background information. It was supplemented with Census data, trade association data (particularly with respect to industry energy usage) and the Energy Consumption Data Base.

Our second stage was to contact gas users in order to learn their own projections for unit energy use and alternative fuel use plans, as well as the factors which governed their oil versus gas decisions. Our contacts included 25 power companies, 80 industrial users and 60 commercial users.

The validity of our sample was enhanced insofar as it directly represented over half the gas usage in certain industries such as paper, steel, oil refining and petrochemicals. The power companies we contacted, for instance, used over 70 percent of the Nation's oil and gas employed in making electricity.

We also contacted 55 gas distribution companies to ask about their rates, curtailments, hook-up moratoria, and whether their gas sales were limited more by deficient supply or demand. These companies accounted for over 60 percent of all distribution sales.

Basic assumptions

We made a number of basic assumptions on GNP and oil prices which held across all sectors. Further calculations were made to relate oil prices to refined product prices (notably residual fuel oil) and to relate well-head gas prices to burner-tip gas prices in interstate and intrastate markets.

Oil prices

For the base case, we have assumed oil prices to stay constant in real terms at $28.50 barrel in 1980 dollars ($33.50 in 1982 dollars) until 1985, whereupon they rise 2-1/2 percent annually in real terms through 1990.

Residual Fuel Oil (Resid)

Of all the crude oil products being made, gas competes most directly at the margin with resid, especially in the price range relevant for projection purposes. We have assumed that the price (per Btu) for medium-sulfur resid on a New York Harbor basis will be 84 percent that of the refiner acquisition cost of crude oil (91 percent on a per-barrel basis). This ratio, although higher than the 80 percent average of the 1967-1982 period, is nonetheless lower than other forecasts, notably DOE's. Although the price ratio between resid and crude oil will inevitably rise over time because current prices justify refinery investment in resid-upgrading equipment, we suggest this rise will be both limited and protracted. Refinery investment, in general, is lagging, in part because refineries are not perceived as profit centers either here or abroad. Eight of the ten refiners we talked to had no upgrading projects in the works. Further, although the retirement of the inefficient small refiners (which produce much of their output as resid) was to have raised resid prices, perceptible effects have not yet appeared. At the same time, the increasing heaviness of crude oil will mean that unless refiners do add more equipment, their current refineries will be producing more resid over time. Finally, on the demand side, the market for residual fuel oil is under considerable pressure from natural gas, coal and nuclear power and particularly in the power plant market on both sides of the Atlantic. Hence, the underlying supply-demand factors are working towards an even greater resid glut.

Burner tip gas prices as a function of well-head gas prices

Burner-tip-gas prices reflect three factors:

--the well-head cost of gas,

--the gas consumed in processing and transporting gas,

--capital and operating costs involved in transmission and distribution.

The use of gas in its own processing consumes roughly 7 percent of all gas delivered and is likely to stay at that level. Transmission uses from one to five percent of all gas delivered, a ratio we also believe is likely to stay constant. Using these assumptions and based on conversations with all the major interstate transmission companies, we conclude that around $ .25 ($1980) of the current transmission mark-up represents these gas costs, while another $ .50 represents capital and operating costs. By the same token, we assume all distribution costs and capital and operating expenses remain constant in real terms. Based on our assumptions we have calculated the following burnertip price profiles reported in table 1.

Table 1

Burner-Tip Gas Costs Calculated from Well-Head Gas Costs

("G" represents pipelines' purchased gas costs)

(1980 dollars)

	Interstate	Intrastate
Residential	1.12G + 2.00	1.08G + 1.45
Commercial	1.12G + 1.55	1.08G + 1.00
Industrial (interruptible)	1.12G + .95	1.08G + .30

Certain exceptions to these prices are made for regions whose gas costs are higher due to their import reliance or their high transportation costs. This includes roughly the northern third of the country.

Heating fuels market

We also chose to assume away the two Federal requirements said to inhibit gas demand--incremental pricing and the boiler restrictions of the Powerplant and Industrial Fuel Use Act of 1978 (P.L. 95-620). Incremental pricing, as now administered, would become progressively irrelevant as market forces make industrial gas and resid competitive in price. Similarly, we have encountered no actual instance in which the Fuel Use Act has inhibited the installation of gas-fired boilers.

To understand the upper limits on the demand for gas, we divide energy use into four categories--vehicles, materials, electricity generation and heat fuels. Gas use and heat fuel use are closely associated; 70 percent of all gas is used as a heat fuel and over 60 percent of all heat fuels consist of gas. A breakout by fuel type and sub-use is included in table 2.

Table 2

Energy Use in 1981 Broken Down by Fuel and Sub-use
(totals in quadrillion Btu)

	Vehicles	Materials	Power plant	Heat Fuels	Total
Oil	19.5	4.0	2.2	6.3	32.0
Gas	.6	.9	3.8	14.5	19.8
Coal		1.5	12.7	1.8	16.0
Other			6.0		6.0
Total	20.1	6.4	24.7	22.6	73.8

Note: Heat fuels include around 60 percent of all distillate fuel oil, 35 percent of all residual fuel oil, 40 percent of all LPG, 80 percent of all coke, and 100 percent of all still-gas and kerosene. Powerplant fuels include 5 percent of all distillate fuel oil and 45 percent of all residual fuel oil.

The demand for heat fuels has been declining sharply since 1973, both absolutely and relative to total economic output. The ratio of heat fuels used to real Gross Domestic Product ($1972) has dropped from 25.8 Btu/dollar in 1970 down to 15.4 Btu/dollar in 1981, a forty percent decrease.

While the continuation of this decline is both uncertain and contingent on a given level of energy (mostly gas) prices, it does indicate a trend in energy use. Some of the decline represents a shift to utility-generated electricity as a substitute for direct fuel use or the industrial self-generation of electricity. Another part comes from a shift to lighter manufacturing in the nation's industrial base. The rest represents energy conservation.

Within the heat fuel market, interfuel competition determines gas demand. Of particular note are reasons why customers would use oil for a heat fuel despite the low well-head cost of gas. Some analysts have used the persistence of oil use as proof of latent demand for gas which remains unrealized because of supply limitations. Many such analysts assume that virtually all industrial oil use is fungible to gas once its price is decontrolled. Our 1981 surveys of both industrial customers and gas distributors, however, suggest that there is little or no latent demand. The only gas distributors who report that they are supply-limited have noted that their lack of gas stems from transportation capacity constraints rather than a lack of natural gas reserves.

These surveys also suggest some of the reasons listed below as to why people use oil for uses where gas is feasible--reasons which suggest that people will continue to use oil (although in decreasing amounts).

1. Gas lines do not go everywhere. They are sparse in rural and exurban areas, and in many places in the East and Southeast.

2. The current cost differential between oil and gas may not justify the cost of new gas mains or the premature retirement of oil-fired equipment.

3. Gas is already more expensive than certain types of resid in some areas of the country such as the Pacific Northwest or New England.

4. Wintertime curtailments reduce gas supplies in certain distribution systems. Lingering hook-up moratoria remain in some systems although they are rapidly disappearing.

METHODOLOGY BY SECTOR

We analyzed gas demand as a function of price in the follow: ing sectors: industrial fuel, industrial feedstock, residential, commercial, power plant and self-use (lease-plant fuel and gas pipeline transportation).

Industrial fuel

The industrial demand for gas was calculated for several subsectors and then aggregated. For each manufacturing subsector the following procedure was used. First, total 1980 fuel requirements were estimated. Then, fuel projections for 1985 and 1990 were made based on separate estimates for physical output growth and unit conservation (adjustments for 1985 were made in some sectors to account for faster conservation rates in the first half of the 1980s and to compensate for any unusual circumstances in 1980 base-line fuel requirements). Historical data and model parameters for fuel use in manufacturing are included in table 3.

Energy use in 1985 and 1990 was divided into interstate resid-substitutable uses, potential intrastate resid-substitutable uses and process uses. Coal, wood and off-gas fuel use was then

Table 3

Characteristics of Fuel Use in Manufacturing
(totals in quadrillion BTU)

Historic Data

	Fuels Usage: 1980 Gas	Oil	Oil Resi-dues	Coal	Wood	Resid-Substitutable Share of Gas Usage*	Annual Reduction in Unit Fuel Use 1972-1980
Food	.46	.15		.12		40	-3.0
Paper	.40	.38		.23	1.04	90 (10)	-2.0
Chemicals	1.36	.26	.45	.33		70 (50)	-4.1
Petroleum	.78	.32	1.69			100 (70)	-2.9
Cement, Lime and Lumber	.13	.04		.35	.42	100 (30)	-1.8
Stone, clay and Glass	.48	.05		.02		10	-2.3
Steel	.62	.13		.07		50	-2.2
Aluminum	.29	.01		.09		60 (50)	-4.0
Other Metals	.20	.05		.02		20	-1.9
Mfg. Products	.85	.22		.20		30	-3 to -5
TOTAL	5.57	1.61	2.14	1.43	1.46		

Model Parameters (1980-1990)

	Annual Output Growth (pct.)	Annual Reduction in Unit Fuel Use (pct.)	Percent Shift in Alternative Fuel Use** (pct.)	Minimum Resid Use in Interstate Manufacturing*** (quadrillion BTU)
Food	2.7	-2.0	3	.10
Paper	2.7	-1.1	16	.20
Chemicals	3.6	-3.3	11	.13
Petroleum	-.7	-2.0	11	.22
Cement, Lime and Lumber	1.5	-1.2	9	.02
Stone, Clay and Glass	1.5	-2.2	2	.02
Steel	.9	-2.3	10	.08
Aluminum	1.2	-3.1	4	.00
Other Metals	.0	-2.0	5	.02
Mfg. Products	2.6	-2.8	3	.11

*Figure in parentheses is percent of total gas in that sector going to intrastate market for potential resid-subsitutable uses.

**Alternate fuels include coal, wood, and off-gases. The figure of "3" for food, for instance, refers to a shift in coal use from 16 to 19 percent of all fuel use in that industry.

***Residual fuel oil use in 1985, when the price advantage of natural gas over resid is the same as it was in 1981.

subtracted from total fuel use in the resid-substitutable sectors. Coal and wood use (as a function of gas prices) was projected, in part, through our industrial surveys. Off-gas was defined only for the chemical and petroleum refining industries and was assumed to be a constant fraction of feedstock from 1980 on. Finally, the remaining fuel demand was allocated to oil and gas. First a minimum oil fraction for the interstate resid-substitutable market was calculated for each sector (variously estimated at ten to fifteen percentage points below oil's 1980 share of the total resid-compatible market held by oil and gas). This fraction (applied to remaining fuels demand) is the oil likely to remain in use at gas prices equal to today's levels.

The fuel demand left over was divided between oil and gas based on the price of gas. In the interstate market the well-head price of gas at which one percent sulfur resid and gas prices equilibrate was calculated to be approximately 60 percent that of crude oil. At that price, half of the fungible market goes to resid and half to gas for resid type uses. An 80-20 split towards gas in these sectors occurs when gas prices are ten percent less; an 80-20 oil split occurs when gas prices are 25 percent more.

In the intrastate resid-substitutable market, gas costs more than one percent-sulfur resid when gas is 71 percent of crude at the well-head (73 percent in 1990). At that price, however, gas still captures 75 percent of the resid-type market because a high percentage of intrastate facilities have little or no dual-fuel capacity. Gas and resid capture equal shares only when gas is 25 percent more expensive at the burner tip. Gas dominates process uses in which it competes only against distillate--a more expensive oil product. Even at oil parity prices, gas commands over 70 percent of the process fuel market.

In addition, to the extent that gas prices are higher or lower, conservation efforts will be correspondingly greater or less. As such, we have applied an elasticity of -.12 (1985) and -.25 (1990) to capture the varying conservation performance in these sectors. 1/ Finally, an estimate for gas usage in non-manufacturing industries is added to the total. Key parameters for the industrial sector include:

1. Annual output growth through 1990 (ex-petroleum) is 2.5 percent on a fuels-weighted basis. Modest growth levels reflect the embedding of high energy prices in materials costs which in turn suppress their growth rates. Petrochemical output, for instance, which grew two to three times as fast

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1/Our base-line conservation numbers presume that industrial respondents were reacting to a gas price trajectory which pushes gas prices to 70 percent of current crude oil price.

as the economy before 1973, is not expected to outpace the overall economy by much in the 1980s.

2. Unit fuel use will continue declining at an aggregate rate of 2.4 percent through 1990. For most sectors this represents a slight deceleration of conservation rates observed in the 1970s. Insofar as past rates do continue, however, this reflects the likelihood that natural gas, which accounts for most of industry's purchased fuel, will be much more expensive in 1985 and 1990 than in 1980. It also reflects some substitution of utility electricity for natural gas uses such as mechanical drive or induction heating. Fuels conservation per se has been running .2 to 2.0 percent faster than energy conservation for such reasons. It is notable that those trade groups which have set targets for energy conservation in 1985 foresee a straight-line continuation of 1970s trends.

3. Coal, wood, and off-gas use will grow at modest rates. We expect industry to use 30-55 percent more coal and 30-35 more wood in 1990 than it does today. Other people estimate coal use higher but presume a significant amount of coal-based cogeneration, a factor we did not consider because it had little direct effect on gas demand. Possible increases in gas-based cogeneration would increase industrial gas demand but to the small extent it does so, gas-based powerplant generation may be correspondingly reduced. We expect a forty percent increase in petrochemical use of off gas as feedstock throughput increases but this is partially offset by declines expected this decade in its use for petroleum refining.

4. Some industries, such as the following, can be expected to operate their new plants without much gas and oil, by meeting most total fuel needs through coal, wood, or off-gas:

--petroleum refining,

--ethylene cracking,

--integrated steel plants,

--copper smelters,

--paper and lumber mills,

--cement and lime plants.

These industries account for 55 percent of the fuels used in American industry.

Gas usage in specific industries

Chemicals: Gas needs should remain flat. Chemical output will grow somewhat faster than the economy in the 1980s, but slower than it has since 1973 due to imports from energy-rich countries and the effects of higher embedded energy prices. Conservation will be vigorous, corresponding to our respondents' beliefs that their own fuel needs will stay level despite output gains. If priced to compete with resid in interstate markets, gas will gain on oil over time. However, increased hydrocarbon residues from petrochemical operations will be displacing gas in certain locations; in others coal will, but at rates which will fall below earlier expectations. This is particularly true in Gulf Coast plants far from coal mines.

Paper: Gas and oil will continue to yield to solid fuels, both coal and wood. Among all fuels, oil and gas combined dropped from 48 percent in 1972 to 37-1/2 percent in 1980 and 35 percent in 1981. Paper producers that we spoke to saw a 10-15 percentage point reduction in their total fuel needs met by oil and gas combined by 1990. We thus see oil and gas taking a 20-25 percent share of old capacity fuel needs and less than half that in new capacity (mostly in lime kilns). The remaining competition between oil and gas is biased towards high-sulfur oil; thirty percent of all nonsolid fuel boilers lack a gas connection.

Petroleum refining: Flat demand, continued conservation, and unchanged hydrocarbon residue production (and hence use) spell a sharp decline in refiners' needs for oil and resid. Petroleum demand is likely to stay flat (an average) from 1981 on with increases in petrochemical feedstocks offset by declines in fuel oil demand while vehicle fuels shift in composition but not quantity. The degree of refining should also stay constant--regular gasoline demand will yield to increases in both unleaded and diesel, any increases in the severity of refining necessary to break down heavier crudes and resid will be met by burning the coke produced as by-products of such operations. Meanwhile, off-gas and coke together should satisfy over 70 percent of refiners' fuel needs, up 10 percent from today's levels. Among the leftover oil and gas needs, gas is favored in California and the Gulf, and resid in the East. Dual-fueled refiners will favor resid when its use relieves them of having to sell it in otherwise soft markets.

Steel: Gas use will decline because output will grow slowly and conservation will continue. Long-run tonnage growth may be slightly positive in the 1980s but faster growth will be limited by steel mill closings. Conservation trends will be strengthened by the increased use of continuous casting. When half of this country's steel is so made (circa 1990), total gas savings could reach .1 quads a year. The exhaustion of the simpler housekeeping conservation measures will be offset in part by energy savings from decelerating pollution control requirements. Modest increases in coal (including coking needs) from 70 to 71-74 percent of all fuels used by 1990 may displace some gas, but higher coal usage rates are inhibited by the problems of coke oven operation.

Other metals: Gas used in aluminum production is likely to decline, particularly in the Southwest. Although aluminum product production should keep growing, over half of the industry's direct gas usage goes to make raw aluminum and its feedstock, alumina--materials whose output should stay flat. The industry's self-generation of electricity using gas is likely to keep falling also. Similar declines can be expected in other metal industries because of zero output growth (especially for castings and base metals) combined with normal fuel conservation trends.

Building materials: Process gas usage should stay flat as growth raises and conservation lowers gas needs. Some sectors--fiberglass, containers, pottery and gypsum--should pace the economy, but other sectors--asphalt and concrete, and particularly flat gas and bricks--will lag behind. Gas should be able to keep its market against oil and alternative fuels mostly because it commands a premium in the direct-firing of silicaceous products. Large declines, however, can be expected in the making of cement/lime and wood products in favor of coal and wood residues, respectively.

Food processing: Fuel needs, and hence gas needs, in food production will increase slightly because conservation rates will dip in the 1980s. Many of our respondents note that the easy conservation measures have already occurred, but they still project flat fuel needs for their own companies despite continued output gains. Gas will keep its approximate share if priced below resid and coal penetration, although steady, will be slow. Among the 60 percent of gas used in small boilers and for process uses, gas should more easily retain its predominance.

Other industries: Gas use should hold steady in other manufacturing industries. Total output will continue to increase because energy is only a small fraction of product costs in these other sectors. Nevertheless, conservation rates will be significant particularly in heat-process industries which have become much more efficient in the last three years. The importance of process uses leaves gas in a strong position against other fuels. Although coal will displace some gas in the textile, car, tire and related industries, large fuel shifts will be retarded until the auto market recovers. Among non-manufacturing industries, gas is used in equal measure for rock mining, oil drilling and agriculture. Slow growth will retard gas usage in the domestic rock mining industries; in the latter two, gas is subject to displacement by electricity for use in mechanical drive.

Industrial feedstock

Although natural gas is a feedstock to many chemicals, 75 percent of it goes into making ammonia. Gas is virtually irreplaceable in ammonia manufacture but if its price goes too high, domestic ammonia may be displaced by imports.

Based on interviews with selected ammonia producers, we estimate that ammonia production would stay flat as long as wellhead gas prices stay below $3.00 MMBtu. Slight efficiency gains would reduce gas use from 36 MMBtu/ton (process fuel included) to 34 MMBtu/ton. Total gas requirements would thus decline slightly.

Although low prices allow replacement ammonia capacity to be built, higher gas prices would mean that retired ammonia plants would not be replaced, and oil-parity gas prices would mean premature plant retirements. Capacity declines would be 0, 10, and 30 percent respectively. As for methanol and other feedstock uses, we assumed no net change in their gas requirements, for reasons similar to those in the ammonia industry.

Residential demand

Residential gas use can be divided into space heating (70 percent) and appliances (30 percent). Since space heating both dominates and influences fuel use for appliances, we model it first and use its results to model appliance use.

Space heating

The first step in estimating space heating gas demand was to estimate housing units by region and fuel type (for historical information and model parameters see table 4). To create a 1-1-80 baseline we used the 1980 census, AGA's Gas Housing Heating Survey and EIA's SEDS survey. Changes in gas use for space heating from the baseline come from

a. the disappearance of old housing units at 1/2 percent a year,

b. Conservation trends in existing housing units,

c. Fuel choice and usage rates in new housing units,

d. Oil-to-gas conversions.

Conservation investments reduce fuel use in existing gas-heated units at a rate of one percent a year plus any declines resulting

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1/Linear interpolations are performed for other gas prices. Price effects on new units affect 1985-1989 fuel choices only.

Table 4

Characteristics of Residential Gas Use

(housing units in millions)

Historic Data

	Housing Units by Fuel 1-1-1980					
	Total	Gas	Fuel Oil	LPG	Elec-tricity & Other	Average Heating Degree-days
Northeast	18.4	7.1	8.8	.3	2.2	5600
South	24.2	10.3	2.8	2.2	8.9	2500
Midwest	22.1	15.3	2.4	1.4	3.0	6300
West	15.3	10.1	.6	.5	4.1	3400
TOTAL	80.0	42.8	14.6	4.4	18.2	4400

Model Parameters*
(1980-1989)

	New Housing Units by Fuel			Oil-to-Gas Conversions	Projected Gas-heated Units: 1990
	Gas	Oil	Other		
Northeast	.7	.4	.7	1.9	8.5 - 9.6
South	2.1	.1	5.1	.5	12.1 - 12.8
Midwest	2.4	.2	1.1	.8	17.0 - 17.9
West	2.3	.0	2.4	.1	11.5 - 12.0
TOTAL	7.5	.7	9.3	3.3	49.2 - 52.3

*New housing units and oil-to-gas conversion numbers were generated for residential gas prices of $5.00/MMBtu (1980 dollars). The range for projected gas-heated units covers gas priced from $5.00/MMBtu to $7.70/MMBtu.

from prices over 1979 levels, ($3.50/MMBtu in 1980 dollars). The latter was calculated with an elasticity of -.2, 60 percent of which happens immediately and the rest over the next four years.

We assumed that 17 1/2 million new housing units are added from 1980 to 1989. Forty-three percent of these units are finished before 1985 begins (28 percent in the Midwest, 47 percent elsewhere). Units are distributed to regions in the same way that they were from 1976 through 1979--7 1/2 million for the South, 4 1/2 million for the West, 3 1/2 million for the Midwest, and 2 million for the Northeast.

With low gas prices ($5.00/MMBtu at the residential burner tip), gas achieves a market share of 43 percent among new units with a regional distribution comparable to actual 1980 totals. With high gas price ($7.70/MMBtu) its share of new units falls by a third. 1/ Oil gets a market share of 4 percent, electricity the rest. New houses require 40 percent less gas (12,000 Btu per heating degree day) than existing units did in 1979.

Oil-to-gas conversions proceed at a fixed percentage rate among the stock of convertible oil-heated units (8.1 million units). The percentage is maximized when gas prices are low, ($5.00/MMBtu) but drops to zero at a high price ($7.70 MMBtu) with other rates calculated by interpolation.

Oil-to-gas conversions naturally decline as the target population shrinks. No gas-to-wood, gas-to-electricity, or electricityto-gas conversions were calculated.

Appliances

Calculations on appliance use were limited to water heaters, gas ranges and clothes dryers. Characteristics of gas-using appliances and their projected usage are found on table 5. The projected population of these appliances was calculated by applying fixed usage ratios to the stock of old (pre-1980) and new (1980 on) housing units. Average usage per appliance was calculated by estimating the stock of very old (pre-1973), old (1973 to 1979) and new (1980 on) appliances, with continually falling gas usage rates for each appliance. An additional elasticity of -.1 was applied to waterheating appliances to account for hot water conservation as gas prices rose.

Explanations of key assumptions--Residential Sector

Gas capture rates for new housing units were modelled after the fuel-choices made for units built in 1980--a year when there were few gas connection moratoria left. The 43 percent share in our model is actually larger than the 37 percent share recorded due to adjustments to reflect the fact that

Table 5

Characteristics of Gas-Using Appliances

	Saturation		Unit Fuel Usage by Vintage			Actual/Projected Fuel Usage* (quadrillion BTU)		
	Existing Units	New Units	Pre-1973	1973-1979	Post-1979	1980	1985	1990
Water-heaters	1.0	1.0	29	25	22	1.2	1.1-1.2	1.1-1.2
Oven/ranges	.8	.5	7	5	4	.2	.2	.15
Clothes-dryers	.3	.2	6	4	4	.05	.05	.05

Note: Saturation refers to the ratio of housing units with gas appliance to the total stock of gas-heated housing units. Projections for water-heater fuel usage represent gas prices in the \$5.00-\$7.70/MMBtu range as noted in Table 3.

--housing starts in the gas-using Midwest were unusually low in that year;

--gas is more popular in single-family units which use more energy than in multi-family units, and

--lifting the remaining moratoria on gas hookups will lift capture ratios some.

Much higher capture rates, however, are not realistic in that the late 1960's level of 60 to 65 percent is unlikely to be reattained under foreseeable prices, because

--the price ratio between gas and electricity has, since then, shifted sharply against gas;

--the electric heat pump has become more competitive in warmer regions since then (the gas heat pump is still several years away);

--more and more homes are being built away from metropolitan areas and, as such, further from gas lines; and

--gas distributors may be more reluctant to expand gas mains aggressively than they were then because they are both poorer and more uncertain about future gas supplies.

Basic unit reductions in gas (and oil) demand average one percent annually, over and above any reduction (or addition) in fuel use occasioned by an increase (or decrease) in fuel prices, for the following reasons:

--New energy-saving technologies (e.g., affordable micro-processor controls) will continue to come on the market and introduce fuel-saving techniques which were previously unavailable.

--As with any other major social adaptation, energy awareness takes time to completely diffuse through society. Sometimes these shifts require a generational change in home-ownership.

--Retrofit expenditures do not take place immediately as gas price rise. As with other large claims on incomes, they are scheduled as funds permit. This is particularly true if they occur as a result of major remodeling projects. Hence, the housing stock approaches equilibrium only over time.

--If a housing unit turns over to those unsatisfied with its fuels consumption, retrofit will occur. The reverse, however, does not lead to un-retrofitting.

--The retirement of less efficient units raises the overall average.

Commercial demand

Commercial demand was calculated as the sum of gas use in existing buildings and new buildings, plus or minus fuel switching and adjustments of various sorts.

The first step subdivided the commercial sector into seven subsectors--offices, stores, local use (local government, voluntary organizations, warehouses, gas stations and garages), hospitals, universities, hotels and the Federal Government. Gross fuel-type energy usage was estimated based on Oak Ridge data, EIA's non-residential building survey and EEAs 1974 Energy Consumption Data Base. Further estimates were done for fuel shares.

Fuel use in existing buildings for each subsector was calculated by taking the 1980 base numbers, reducing them to reflect building turnover (at one percent a year) and conservation trends (as established by survey.) Conservation trends were normalized at a gas price of $3.50/MMBtu (at the wellhead). Reductions in unit fuel use at prices higher or lower than $3.50 were calculated by using an elasticity of -.1 for 1985 and -.2 for 1990. Minor sector-specific fuel adjustments were made to accommodate increased coal use in universities, the Federal Government and central district steam systems. Table 6 summarizes the adjustments we made for commercial gas usage.

Fuel use in new buildings was projected by calculating new floor space as a ratio of 1980 floor space. To do this we projected total floor space by reference to appropriate net growth rates and then subtracted the 1980 floor space which remained after annual retirement. Gas usage was calculated by multiplying new floor space by a sector-specific ratio which simulates the greater energy efficiency of new buildings (15 to 40 percent reduction from 1980 usage levels) and estimating the percentage of new floor space heating with gas. Minor adjustments make gas's share of new floor space vary with gas prices and some reductions in certain sectors to reflect lower heating needs due to the movement of new commercial floor space construction to the sun belt.

The model assumed no net oil-to-gas fuel switching when wellhead gas prices were $3.50 MMBtu (1980 dollars), so that commercial users paid as much for gas as for lowsulfur resid. Lower gas prices induce oil-to-gas conversions, higher prices

Table 6

Characteristics of Commercial Gas Usage

(in quads)

	Fuel Usage: 1980				Annual Floor-space Growth	Unit Fuel Usage (1980 Av. = 1.0)			Projected Percent Share of New Floor Space by Heating Fuel**	
	Gas	Oil	Coal	Other*		New Units	Old Units 1985	Old Units 1990	Gas	Oil
Offices	.49	.22	.02	.30	3 pct.	.60	.88	.82	35	5
Stores	.69	.19		.30	2 1/2	.67	.86	.80	50	5
Local Use	.51	.23	.02	.15	1	.70	.93	.88	55	10
Hospitals	.29	.07	.01	.05	4	.85	.93	.87	65	10
Universities	.20	.08	.03	.04	1	.75	.90	.85	60	10
Hotels	.15	.05		.05	2 1/2	.60	.82	.76	60	10
Federal Govt.	.12	.09	.05	.02	1	.65	.89	.83	50	25
TOTAL	2.45	.93	.13	.91	2.2	.65	.89	.83		

*Estimated usage of electricity for space and water heating.

**The remaining percentage (up to 100 percent) is either electricity or coal for steam heating systems.

Note: Certain exogenous adjustments were made to reflect increases in coal use for central district heating systems (offices), universities, and Federal Government buildings, and decreases in gas use due to regional shifts towards the sun-belt (local use, universities and especially hotels). Sun-belt shifts were incorporated directly into new floor space projections in the office and store sectors.

motivate dual-fueled installations to use resid. Every $1.00/ MMBtu difference in gas price motivates fuels switching at a rate equal to fifteen percent of the baseline oil usage.

Finally, we adjusted certain totals to account for changes in gas-fired electricity production (including cogeneration), refuse-derived gas, and refuse-derived steam as a gas substitute.

Selected characteristics of commercial gas usage

A critical variable in calculating gas needs in the 1980s will be whether new buildings use gas or electricity for heating. Gas penetration will be higher than it was in the 1970s, because availability has improved, but worse than in the 1960s because its relative price has not. Gas shares in new buildings will approximate current shares in sectors which tend toward steam systems--universities, hospitals, hotels, Federal buildings and local institutions. Gas shares should also hold up where buildings are small (and surface-to-volume ratios are high). Electricity is likely to maintain a high share for large buildings. This is because their builders are especially sensitive to first-cost considerations (many such buildings are speculative ventures) and less sensitive to operating costs. Large buildings, anyway, have relatively low heating costs; office buildings, for instance, only need heat for the first eight feet in from the wall, large department stores need heat only when temperatures drop below freezing. Ventilation and air-conditioning are relatively more important and electricity dominates gas for such uses. Around 90 percent of the new high-rises in downtown Boston and Chicago, for instance, are heating with electricity.

Conservation rates are another critical variable. Many of our respondents have already achieved large reductions--ten to fifteen percent--in unit fuel requirements in the last three years. Many have new conservation programs underway, and expect further reductions--up to twenty percent--in unit fuel needs. One factor supporting greater conservation is the recent improvements being made in microprocessor controls capable of optimizing lighting and heating needs.

Conservation may lag in local-use buildings. Due to their public or semi-public nature, their adjustment to higher prices is relatively slow and based heavily on voluntary forbearance by users (which, by nature, can be temporary). Certain analysts also believe that conservation will proceed slowly in buildings where owners, managers, and occupants are different people (none of whom will invest much in conservation). The latter effect may be minor. Even if half of the buildings in the office, store, and local use sectors are rented (so that conservation rates are reduced to one percent a year), the resulting increase in gas demand is no more than two percent in both 1985 and 1990.

Table 7

Characteristics of Electricity Production by Region

(Output in billion kwh,. Capacity in thousand megawatts)

Historic Data

Region	Electricity Output 1973	Electricity Output 1980	1981 Electricity Output by Fuel: Coal	Nuclear	Hydro	Gas	Oil	Solid Fuel Generating Capacity as of 1-1-81: Coal	Nuclear
Northeast	187	187	19	43	31	12	78	3	9
Mid-Atlantic	178	191	122	37	2	8	23	25	9
Va-Car	110	148	99	42	5		5	19	9
Southeast	219	298	159	50	15	17	47	35	11
Midwest	487	575	491	60	7	4	10	111	15
Southwest	114	154	49	9	2	87	6	10	2
Texas	134	203	71		1	134	1	12	
Midnorth	109	165	117	19	33	2		27	4
Pac. NW	109	129	9	9	123			2	2
Pac. SW	193	228	66	3	39	78	28	12	3*
TOTAL	1840	2278	1202	272	258	342	198		

Model Parameters

Region	Scheduled Capacity Additions by 1990** Coal	Nuclear	Units lost	Available Power from Coal, Nuclear & Hydro Units in 1990	Projected Demand in 1990	Need for Gas- and Oil-fired Power in 1990***		Need for Gas and Oil in 1990 (Quads)
Northeast	6 (4)	5		160	195	35	(50)	.43
Mid-Atlantic	4 (2)	6	-5	202	220	18	(15)	.21
Va-Car	3 (1)	6	-2	202	210	8		.05
Southeast	13 (1)	6	-2	352	420	68	(50)	.60
Midwest	30	13	-10	833	685	-		.05
Southwest	15	6		175	210	40	(70)	.60
Texas	13	4		158	300	142	(110)	1.34
Midnorth	16		-1	272	260	-		-
Pac. NW	1	2	-1	157	155	-		-
Pac. SW	11	10		247	295	48	(60)	.60

*Includes geothermal.

**Coal number in parentheses represents oil-to-coal conversions as included. Nuclear includes geothermal (Pacific SW) and Canadian imports (Northeast and Mid-Atlantic). Units lost are coal retirements except for nuclear retirements (Mid-Atlantic, Pacific NW).

***Figures in parentheses based on projections submitted by utilities. Total oil and gas needs in the next column over were based both on model results and utility responses.

Finally, our projections for the Federal Government's gas usage (90 percent of which is defense-related), assume that the Federal Energy Management Program is administered successfully.

Power plant demand

Gas use by powerplants was projected by calculating how oil and gas must be used when available coal, nuclear and hydro power plants are running at capacity (see table 7), and then calculating gas-to-resid balances for each region at various prices.

The United States was first divided into ten regions resembling those of the National Electric Reliability Council.

National electricity demand was then projected forward at 2 and 2/3 percent annually from 1980 onwards. Regional breakdowns were generated by the shift and share method so that each region's share of the Nations total demand rises (or falls) as much from 1980 to 1990 as it did from 1973 to 1980. Minor adjustments bring regional growth rates in slightly towards national averages.

Available coal capacity in 1990 was assumed to equal coal capacity in 1-1-81 (257 gigawatts) plus 90 percent of all capacity scheduled to be onstream by 1-1-90 as reported in DOE's 1980 Inventory of Powerplants (104 gigawatts) plus scheduled coal conversions (7 1/2 gigawatts) minus retirements in the historic coal-using areas (19 gigawatts).

Similarly, available nuclear capacity was assumed to equal actual nuclear capacity in 1-1-81 (62 gigawatts) plus 90 percent of all capacity scheduled to be onstream by 8-1-86 (54 gigawatts) minus a few retirements (3 gigawatts). Geothermal capacity triples to 3 gigawatts by 1990. Coal, nuclear and geothermal capacity was loaded at 58 percent capacity (63 percent for Texas lignite plants). Hydroelectric and other output was assumed to add 350 billion kwh of supply and additional Canadian imports add 10 billion kwh.

Regional demand was satisfied first by coal, nuclear, hydroelectric geothermal, and contracted imports. Demand remaining in each region was then allocated to oil and gas. Regional totals were adjusted to reflect gas and oil use reduction projections made by utilities polled in early 1981 by GAO (in connection with a study of the "off-gas" provisions of the Power Plant and Industrial Fuel Use Act of 1978 (P.L. 95-620).

Finally, breakdowns between oil and gas were made regionally by reference to comparative prices between delivered gas and available resid, the existence or lack of dual-fired powerplant capacity and regional transmission limitations.

Table 8

Gas Consumption in 1980 and Demand Model Results for

Gas Consumption in 1985 and 1990

(quantities in quadrillion BTU, price of gas in 1980 dollars per MMBtu at the wellhead)

Year	1980	1985				1990		
Gas Price	1.60	2.20	3.00	3.80	4.60	3.00	3.80	4.60
Gas Demand								
Industrial (fuel)	6.0	6.1	5.0	4.0	3.4	5.2	4.0	3.2
" " (feedstock)	.9	.9	.9	.9	.8	.9	.8	.7
Residential	5.2	5.2	5.0	4.9	4.8	5.1	4.9	4.7
Commercial	2.5	2.6	2.4	2.2	2.1	2.5	2.2	2.0
Power-plant	3.8	3.5	3.1	2.4	1.6	2.8	2.3	1.7
Self-use	2.0	1.9	1.8	1.6	1.4	1.8	1.5	1.3
TOTAL	20.4	20.2	18.2	16.0	14.1	18.3	15.7	12.6
Total Heat Fuels	23.5	22.3	21.8	21.3	21.0	21.1	20.4	19.8
Percent Gas	64	68	63	58	53	67	60	55

Regional outcomes for powerplant demand

The split between oil and gas will vary by region. In the Northeast, for instance, oil will continue to dominate. Transmission is expensive and capacity is limited in the winter; furthermore, many powerplants lack gas connections, something even more true in the Mid-Atlantic region. Tight environmental requirements, however, favor gas in or near New York City. Florida is similarly expected to favor oil use due to limited gas transmission capacity as well as the availablility and low cost of high-sulfur resid.

Powerplants in Texas and the Southwest, however, will use gas because most of them lack a capacity to use resid. What dual-fired capacity exists lies by the Gulf, and near the Mississippi, and would switch, but because of transportation differences, the switchover point is a dollar/MMBtu later than in the East. Gas is also favored in California and adjoined states due to tight environmental requirements. Oil will continue to be used, however, whenever transmission lines are full as they are in the winter. As for other regions, minor amounts of oil and gas will still be required for peaking purposes with current fuel share breakdowns continuing.

Gas processing uses

Natural gas is used for its own field processing and transmission. Our model assumes such uses will still require a constant fraction of all domestic natural gas through 1990. Gas used in the field for lease plant and other processing uses seven percent of all wellhead production. Gas used for transmission averages three percent nationwide.

SUMMARY OF MODEL RESULTS (See table 8)

Industrial fuel

The industrial demand for natural gas is very sensitive to price because most of it can be substituted for by petroleum products--most notably resid.

If gas prices stabilize at today's levels, industrial gas demand would probably remain flat through most of the decade. Although gas would pick up as much as a third of oil's 1980 market share, it would yield to coal, wood and off-gas (hydrocarbon residues from processing crude oil or petrochemicals). Higher gas prices would mean much less gas demand. A wellhead price equal to 70 percent of crude would reduce industrial gas demand a third--by 1985, 75 percent would be lost to resid; 10 percent to coal or wood and the rest to conservation. Over five more years gas would lose twice as much market to solid fuels and conservation.

Residential demand

Residential gas demand is expected to be nearly flat under most scenarios. At current or slightly higher price, demand in 1990 is near current levels; with prices comparable to oil heating, demand drops ten percent in the early 1980s and does not recover any ground in the latter half of the 1980s.

Commercial demand

Trends in gas usage in industrial buildings lie midway between trends in the residential and industrial market. If gas prices are less than thirty percent over current levels, demand will be roughly what it is today. Higher gas prices, however, can reduce demand as more new floor space chooses electric heat, large dual-fueled users choose resid over gas, conservation efforts intensify, and alternate energy projects proliferate. If gas prices rise to distillate fuel oil levels, demand in 1990 would fall by over twenty percent from current levels.

Powerplant demand

Barring a financial collapse of the nation's electric utilities, their total demand for oil and gas (together) is likely to keep declining through the 1980s. Total oil and gas demand was seven quads in 1978 and six quads in 1981; we project a further decline to five quads by 1985 and four quads by 1990. If that is so, the use of gas itself would also decline regardless of how competitive it was against resid. If gas prices stay near current levels, gas usage would decline by a quarter from 1980 to 1990 while oil usage would drop 60 percent. If gas is priced at oil-parity levels, however, its use would decline by 70 percent and would be restricted to utilities without resid capabilities.

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