Factors Affecting U.S. Oil & Gas Outlook

A Report of the National Petroleum Council

February 1987

NATIONAL PETROLEUM COUNCIL

1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

February 24, 1987

The Honorable
John S. Herrington
Secretary of Energy
Washington, D.C. 20585

My dear Mr. Secretary:

The National Petroleum Council strongly believes that the United States and other consuming nations face the serious threat of a repeat of the energy crises of the 1970s. We are confronted with a rapidly growing oil import dependence, which will increase our vulnerability to a supply disruption, undermine our national security, accelerate our balance of trade problems, and compromise our foreign policy. Mr. Secretary, we urge you and the Administration to join us in making every effort to alert the nation to this grave situation, and to thoroughly review all of the various options available to prevent a reoccurrence of these crises. The Council stresses the urgency of the situation and the need for prompt action.

It has become evident in recent months that there is a lack of awareness or appreciation on the part of the general public and Congress of the long-term threat to our economy and national security posed by Middle East OPEC's ability to manipulate oil supply and thus price. We have seen that these foreign countries, acting in their own self-interest, can radically change world oil markets overnight. The United States and other consuming nations must be vigilant to these actions and be prepared to respond to ensure that their economic prosperity and energy security are not jeopardized.

In the first months of 1986, crude oil prices fell 60 percent, providing a windfall to consumers and reducing inflationary pressures. Even though oil prices have rebounded somewhat in recent months, the 1986 price drop and the uncertainty that it created have sown the seeds for a dramatic reversal of the progress made in conservation and in domestic oil and gas production over the last ten years. During 1986:

- Domestic oil production dropped 700 thousand barrels per day (8 percent)
- Oil demand increased 2.5 percent despite a sluggish economy
- Oil imports rose 23 percent (to 33 percent of supply)
- Exploration and production budgets were cut one-third
- Oil and gas drilling activity fell 50 percent (85 percent since 1981)
- Direct industry employment dropped by over 150,000 jobs (26 percent).

The decline in activity and industry capability will reduce production in the future, which, when combined with growing demand, will result in even greater dependence on imports. The nation must address the increased vulnerability that will inevitably result from a continuation of these trends.

A survey conducted by the Council in the second quarter of 1986 shows net imports rising from 27 percent of supply in 1985 to over 50 percent in the early to mid-1990s. The survey also shows that as early as 1990 OPEC capacity utilization could exceed the 80 percent level that preceded the 1970s energy crises. Data for the last two quarters of 1986, combined with adverse changes in the tax law, raise the fear that such levels of imports and OPEC production may be reached even earlier.

There are initiatives that the federal government can undertake to slow or reverse these trends. None of these is without social, economic, and political costs that must be weighed carefully against the benefits. The price collapse of 1986 has brought forth proposals that call for immediate intervention by the U.S. government. These include, singly or in combination: establishing floor prices or import fees; levying consumption taxes; and providing domestic production and/or exploration incentives.

Other options address more chronic but still significant problems for the U.S. oil and gas outlook. These include: natural gas decontrol; public lands access; overall tax policies relating to extractive industries; and federal research policies.

Finally, there are options that can help mitigate the vulnerability of the U.S. economy to future price shocks and shortages. Among these options are: energy conservation and the use of alternative fuels; diversification of oil supply sources; diplomatic actions to increase the interdependence of producing and consuming nations; and monetary and fiscal policies to mitigate the effects of oil price shocks. These, of course, are in addition to the expansion and use of strategic petroleum reserves in the United States and other countries.

As you are well aware, the U.S. petroleum industry is in general agreement with the desirability of prompt government action on the options in the latter two categories in order to protect consumers, the economy, and the national security from vulnerability to price shocks and shortages. However, the industry is not united on the advisability of implementing some of the interventionist options in the first category.

On behalf of the members of the Council, I am pleased to transmit to you herewith the National Petroleum Council's report, Factors Affecting U.S. Oil & Gas Outlook, which was unanimously approved by the Council at its meeting today. This report, prepared in response to your request, provides extensive data and analyses that underscore our concerns. We sincerely hope that it will be of value to you, to the Administration, and to Congress in agreeing on the appropriate actions to serve the interests of consumers and the nation.

Respectfully submitted,

Ralph E. Bailey

Ralph E. Bailey
Chairman

Enclosure

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James L. Ketelsen, Chairman
Committee on U.S. Oil & Gas Outlook

NATIONAL PETROLEUM COUNCIL

Ralph E. Bailey, *Chairman*
Edwin L. Cox, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U.S. DEPARTMENT OF ENERGY

John S. Herrington, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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Introduction

STUDY REQUEST

On September 23, 1985, Secretary of Energy John S. Herrington requested that the National Petroleum Council (NPC) study the factors affecting the nation's future supply of and demand for oil and natural gas. The Secretary's letter also requested that the study examine the factors that precipitated the 1970s energy crises, their financial impact on the nation's economy, the appropriateness of government's response, and the potential for the recurrence of such crises. In addition, the Council was asked to advise on how the vulnerability to future energy crises could be avoided or mitigated. The Council agreed to this request. The letter from the Secretary is provided in Appendix A.

STUDY ORGANIZATION AND METHODOLOGY

To assist in responding to the Secretary's request, the Council established the Committee on U.S. Oil & Gas Outlook under the chairmanship of James L. Ketelsen, Chairman of the Board and Chief Executive Officer of Tenneco Inc. Donald L. Bauer, Principal Deputy Assistant Secretary for Fossil Energy, U.S. Department of Energy, served as Government Cochairman of the Committee. The Committee established a Coordinating Subcommittee to aid it in directing the overall study effort, and three task groups—the Economic and Environmental Impacts Task Group, the Historical Factors Task Group, and the Future Supply/Demand Factors Task Group. The broad membership of these groups included representatives of both major and independent petroleum companies, natural gas producers and pipelines, the petroleum services industry, the electric power and automotive industries, energy trade and research associations, and the academic, consulting, financial, and environmental communities. Rosters of these study groups are provided in Appendix B.

In order to gauge the impact of the 1970s energy crises, the Economic and Environmental Impacts Task Group used an econometric model to simulate the economy's performance in the absence of the price shocks and shortages. The results of the model analysis are found in Chapter Three and Appendix C. The Historical Factors Task Group discussions included guest panelists who were responsible for developing and implementing many of the federal government's policy and regulatory responses to the 1970s energy crises, in order to provide insights into the rationale behind such responses.

The approach used to examine the factors that affect the supply of and demand for oil and gas was to first identify the various factors and then to analyze how they operate to increase or decrease supply and demand.

As one tool for this analysis, a survey was conducted of future supply/demand outlooks utilizing two simplified price trends provided by the Department of Energy. This survey was sent to 52 industry, utility, government, consulting, and financial community representatives; 33 responses were received. The survey results illustrate the sensitivity of supply and demand and future drilling activity levels to oil prices and the resultant changes in U.S. vulnerability to future oil supply disruptions. Results of the survey are discussed in Chapter Five and Appendix D.

Another survey to elicit views on the near-term outlook for drilling was sent to approximately 7,000 members of the Independent Petroleum Association of America (IPAA) and to the Society of Independent Professional Earth Scientists (SIPES); 1,023 responses were received. Summary results of the IPAA/SIPES Drilling Survey are discussed in Chapter Five and Appendix E.

The military mobilization aspects of national security and the steps to manage an energy crisis once it occurs were in general considered to be beyond the scope of the study.

INTERIM REPORT

At the time the Committee held its initial meeting on April 22, 1986, the price of oil had been on a severe decline for over four months. The spot price of West Texas Intermediate crude oil had dropped from about $32 per barrel in November 1985 to under $12 per barrel, a decline of over 60 percent. In the first four months of 1986, employment in oil and gas extraction had fallen 21 percent, a total of 127,000 jobs. Severe cutbacks in exploration and development budgets were being announced almost daily. In short, much of the exploration and development sector of the petroleum industry was being dismantled by the rapid decline in the price of oil.

The Committee considered it imperative that an interim report be developed and published no later than October 1986, focusing on the recent severe drop in oil prices and its impact on the oil and gas business—and, in turn, on the economic and strategic security of the United States. An interim report was developed and transmitted to the Secretary on October 9, 1986.

FINAL REPORT

This report is divided into three parts: A summary, the main report, and appendices. The summary section is further divided into an executive summary, conclusions, options, and a report summary. The main report is grouped into three sections. The first section, Chapters One through Three, contains a discussion of the historical perspective of the 1970s energy crises and U.S. policy responses, the economic impacts of these energy crises, and the effects of the recent price decline. The second section, Chapters Four through Eight, contains discussions of the four major categories of factors affecting U.S. oil and gas supply and demand—economic factors, physical factors, institutional factors, and international factors. The third and last section, Chapter Nine, contains a discussion of policy options for avoiding or mitigating U.S. vulnerability to future energy crises.

Executive Summary

With the precipitous drop in oil prices, U.S. petroleum exploration and development budgets have been slashed, drilling has fallen drastically, major personnel layoffs have occurred in every segment of the industry, reserves and production are declining, and the productive capacity of the industry is being seriously threatened. The petroleum producing areas of the nation have been devastated. These events have increased and continue to increase the nation's dependence on oil imports and, thus, subject the United States to a dangerous level of vulnerability.

Two key characteristics of oil and natural gas distinguish them from other commodities and give rise to national security concerns. First and foremost, the use of oil and natural gas is pervasive in the U.S. economy, accounting for two-thirds of the nation's energy requirements. Second, there are no ready substitutes for many petroleum products. The economic impacts of future oil price shocks will depend on many factors. Nevertheless, as U.S. import dependence rises over time, the economic damage that would arise from an energy crisis inevitably increases.

The concentration of oil reserves in the Middle East increases the likelihood of volatile prices and supply disruptions in the future. On a per barrel basis, U.S. oil finding and lifting costs are many times higher than in the Middle East. This allows Middle East producers the flexibility to adjust prices and production policies to meet internal needs. OPEC's decisions concerning the level of production will directly influence world price levels and simultaneously impact the economic well-being of the nation and the major segments of its industrial base. These factors create great concern about future U.S. national security.

Based on geology and on geophysical data, the United States has substantial undiscovered oil and gas resources. These resources are relatively high cost because they are located either in smaller fields or in remote and hostile environments. Discovery and development of these resources will require significant investment and development of new technology.

The reductions in the level of exploration and production activity brought on by a continuation of lower prices and reduced cash flow cannot be quickly reversed. Reduced incentives including the price decline have significantly decreased the willingness and ability of external sources to support the industry. The time lag required to improve the industry's productive capacity will depend on both the depth and duration of these conditions, which impair the availability of investment capital, manpower, and equipment. This increases U.S. energy vulnerability and places the nation at greater risk.

While the recent oil price decline has affected all segments of the industry, it has been particularly onerous for the oil field service industry. Eighty percent of the recent increase in unemployment in the oil and gas extraction industry has occurred in this area. Equipment is being lost, either through lack of maintenance, cannibalization, or liquidation. Skilled and professional personnel with years of training and experience are unemployed or moving to other industries. Any future increase in the demand for oil field services will require the service and supply industry to be rebuilt.

There is no question that depressed conditions in the petroleum industry will affect the long-term welfare of the nation. Until the economics of oil and gas exploration improve appreciably through increased prices, reduced taxes, or other incentives, U.S. exploration will remain stagnant, dependence on imports will increase more rapidly, and the nation's vulnerability to oil price and supply shocks will rise to an excessively dangerous level. All of this will seriously affect the nation's security and economic stability.

Since the United States remains vulnerable to future disruptions, government should carefully consider whether measures should be taken to alter these trends or otherwise reduce the nation's energy vulnerability. Energy policy options fall into two broad categories: (1) those that have been considered for some time as viable options for the longer-term benefit of energy supply and demand in the United States and (2) those that have recently been considered as possible ways to counteract the significant effects of the recent price decline. In view of the importance of energy to the nation and the complexity of the security issues, every effort should be made to formulate these and other options that could conceivably satisfy the objectives of improved energy security through the development of oil, gas, and alternative fuels, and through conservation.

Conclusions and Options for Consideration

CONCLUSIONS

The precipitous 60 percent drop in oil prices early in 1986 was widely heralded as "good news" for consumers and the economy in general. Almost immediately, the price drop reduced inflationary pressures, decreased energy costs for manufacturers and consumers, and lessened the nation's oil import bill. The initial inability of the Organization of Petroleum Exporting Countries (OPEC) to arrest this price slide was viewed by many as a precursor to the "inevitable" demise of the oil cartel.

Lost in the public's euphoria over lower energy prices and complacency with the current world oil surplus are the seeds for a return to the crisis conditions of the 1970s. The continuation of lower prices has already contributed to increased consumption and reduced domestic production from existing wells. More importantly, the continuation of depressed prices and the prospects for continued softness have drastically curtailed domestic drilling and exploration activity, undermining the ability of U.S. producers to meet future energy needs. Further, in the wake of this price plunge, the domestic oil and gas service industry has been devastated.

A continuation of lower prices will result in further increases in consumption and a greater reliance on imported oil. Lower oil prices will necessarily exert downward pressure on natural gas prices and will ultimately reduce deliverability of domestic gas supply. The concentration of oil reserves in the politically unstable Middle East increases the likelihood of volatile prices and supply disruptions in the future. These factors create great concern about U.S. national security—from the standpoints of defense, diplomatic options, and the economic well-being of the American people.

U.S. Oil Import Dependence Is Rising

Even before the recent price fall, forecasts indicated that the United States and other non-communist countries would become increasingly dependent on oil imports. Recognizing this, Secretary of Energy John S. Herrington, in his letter of September 23, 1985, requested that the NPC undertake a study of the factors affecting the nation's future supply of, and demand for, oil and natural gas. The recent price fall has accelerated the rate at which the United States is becoming more dependent on oil imports.

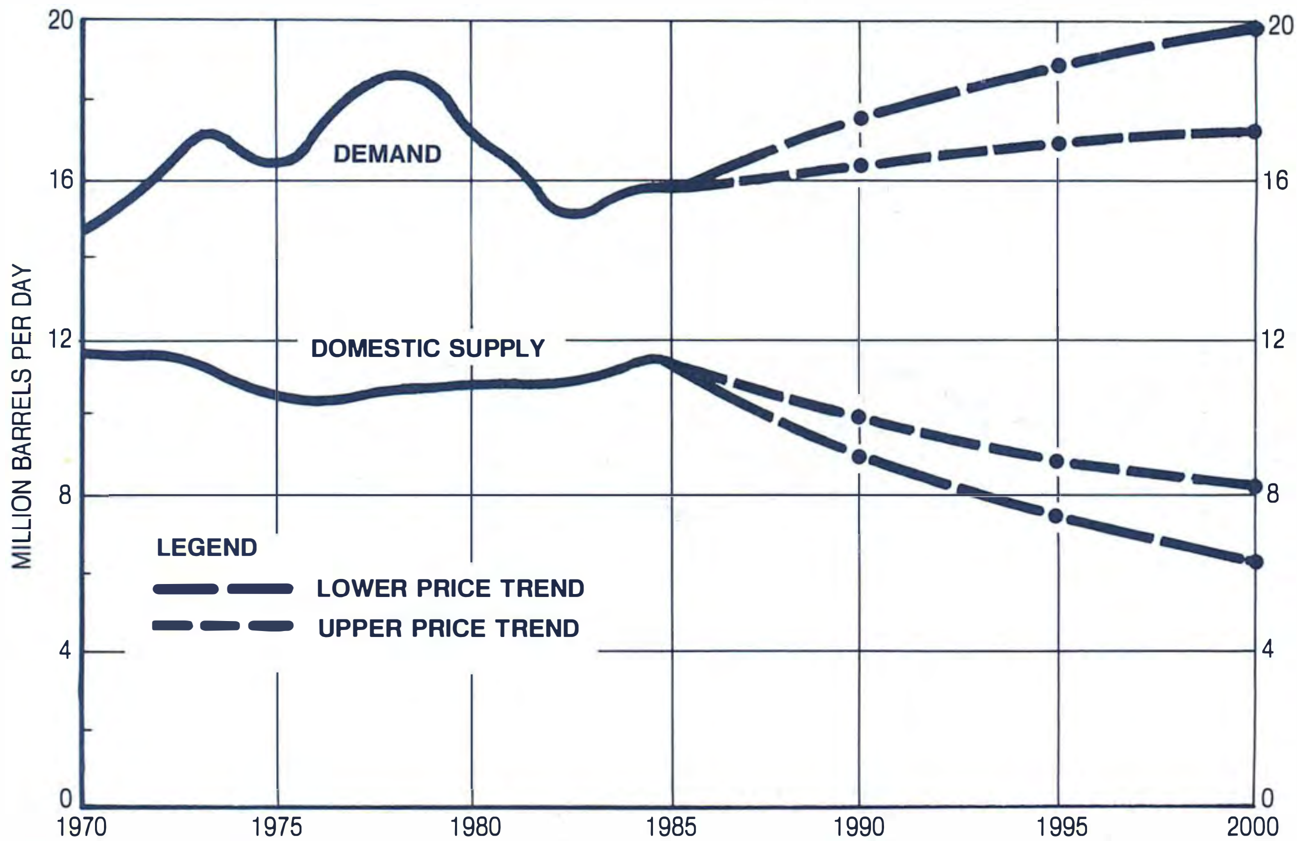
A survey conducted in June 1986 by the NPC shows in Figure 1 that net imports of crude oil and refined products would rise from 27 percent of consumption in 1985 to 38 to 48 percent in 1990 and 47 to 60 percent in 1995. Figure 2 presents the U.S. oil demand and domestic supply trends of the NPC survey. In 1986, actual import dependence was 33 percent, about 30 percent of the increase in the dependence from 1985 to 1990 under the lower price trend.

More importantly, the survey indicated that the share of oil supplied to the non-communist world from Middle East OPEC[1] would increase from 21 percent in 1985 to 25–32 percent in 1990 and to 35–46 percent in 2000.

[1]Middle East OPEC includes: Iran, Iraq, Kuwait, the Neutral Zone, Qatar, Saudi Arabia, and United Arab Emirates.

NOTE: Potential import levels are based on responses to an NPC survey of future supply /demand outlooks that utilized two oil price trends provided by the Department of Energy: an upper price trend starting at $18 per barrel in 1986 and growing at a real rate of 5% per year to $36 in 2000, and a lower price trend starting at $12 per barrel in 1986 and growing at a real rate of 4% per year to $21 in 2000. The survey collected data for 1990, 1995, and 2000. Trend lines are drawn through the survey data points.

Figure 1. Net U.S. Oil Imports as a Percentage of Oil Consumption.



NOTE: The survey collected data for 1990, 1995, and 2000. Trend lines are drawn through the survey data points.

Figure 2. U.S. Oil Demand and Total Domestic Supply.

Higher U.S. Oil Import Dependence Increases Vulnerability

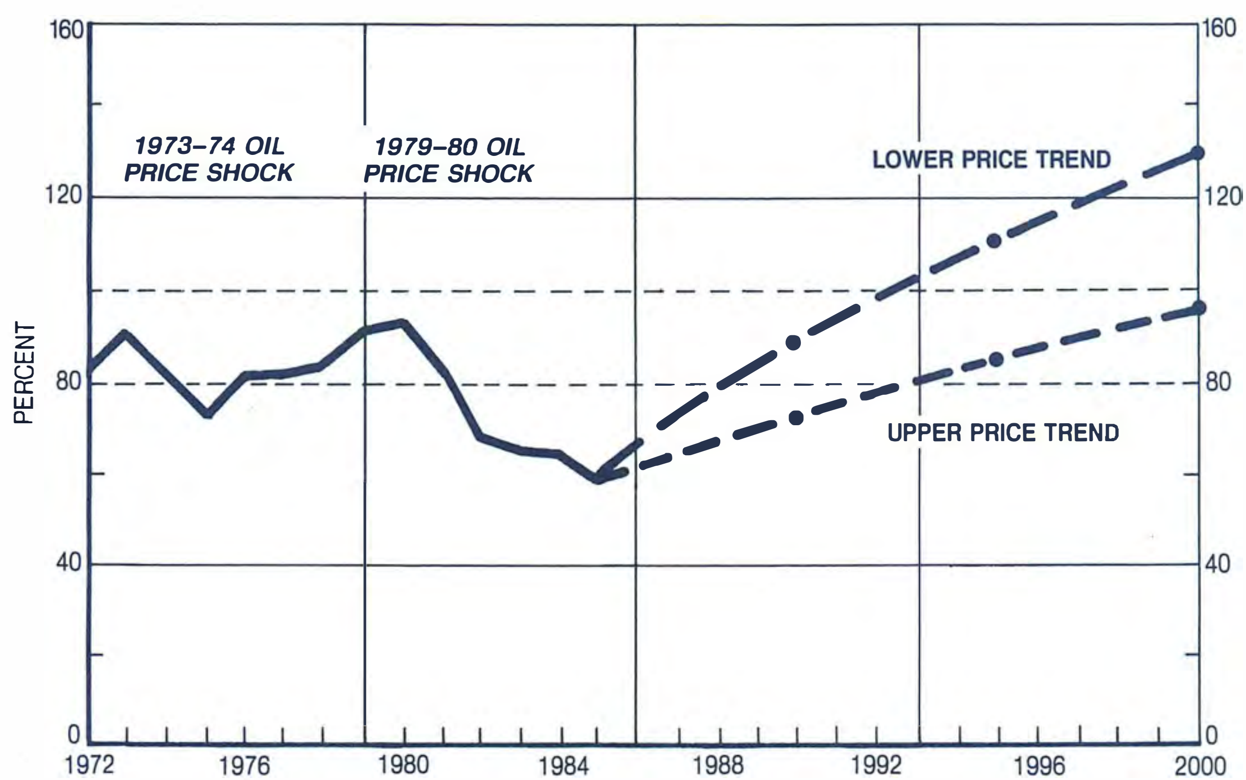
In discussing the national security implications of petroleum, the terms "dependence" and "vulnerability" are often used interchangeably, but it is important to differentiate between these related concepts. "Dependence" on imported oil is measured by the ratio of oil imports to total oil demand. "Vulnerability" is measured by the potential damage a physical shortage and/or a rapid and significant oil price change could cause the U.S. economy. Increased vulnerability limits the nation's diplomatic and defense options. Further, the likelihood of such events occurring must also be considered in assessing vulnerability.

Crude oil prices are determined in the world market and will continue to be, regardless of the extent of U.S. oil import dependence. The greater the nation's dependence, however, the more difficult it will be for the economy to adjust to future crude oil price increases. Higher levels of dependence require larger U.S. exports or greater adjustments in the international value of the dollar to pay for higher priced imports than would be the case with lower dependence. In short, the United States will continue to be vulnerable to supply shortages and significant price changes in the world market.

Two key characteristics of oil and natural gas distinguish them from other commodities and give rise to national security concerns:

- First and foremost, the use of oil and natural gas is pervasive in the U.S. economy, accounting for two-thirds of the nation's energy requirements. In addition to supplying transportation, military, and agricultural needs, oil and natural gas are the major fuels for heating private homes, commercial establishments, and factories. These fuels heat 75 percent of the nation's occupied housing units. Furthermore, petroleum is used in the production of a wide variety of other consumer products, ranging from building materials and clothing to furniture and cosmetics.
- Second, there are no ready substitutes for many petroleum products. For example, oil and natural gas account for 99.8 percent of the transportation sector's energy requirements.

A major factor affecting price instability since the mid-1970s has been the shift of swing oil productive capacity to Middle East OPEC. During the 1970s, when OPEC's capacity utilization level moved above 80 percent, its members were able to increase prices and maintain them at high levels (see Figure 3). The NPC



NOTE: The survey collected data for 1990, 1995, 2000. Trend lines are drawn through the survey data points.

Figure 3. OPEC Crude Oil and Condensate Capacity Utilization (Percentage of Total Capacity; Post-1985 Capacity Held Constant at 27 Million Barrels per Day).

survey indicates that OPEC could again be producing at 80 percent of its current capacity before 1990. For the lower price trend to persist beyond 1990, OPEC would need to develop additional capacity before 1995 in order to meet non-communist world demand. Alternatively, OPEC could temper demand by raising oil prices more rapidly.

As is the case with most commodities, a small shortage or a small surplus can have a major impact on prices. As occurred in early 1986, an increase in oil supplies of as little as 2 million barrels per day (less than 5 percent of non-communist world oil demand) can cause prices to plummet. Similarly, a small reduction in supply can cause prices to increase sharply, as was demonstrated in the 1970s. The temporary net loss of world oil supplies during the Iranian revolution was 2 to 2.5 million barrels per day, only 4 to 5 percent of non-communist production, yet prices more than doubled, and finally, by 1981, tripled.

U.S. Economy Remains Vulnerable to Oil Price Shocks

History amply demonstrates how major oil price increases can impact the U.S. economy. When each of the 1970s energy crises occurred, the U.S. economy shifted from boom to recession. Analysis indicates that the oil price shocks caused a 2.5 to 3.5 percent fall in the value of goods and services produced, a 1.5 to 2.0 percentage point rise in unemployment, and a 3.0 percentage point jump in inflation.

The economic impacts of future oil price shocks will depend on many factors, principally the severity of the shocks, the level of import dependence, the availability of substitute fuels and stockpiles, and general economic conditions. Because the energy intensity of the economy has been reduced, the adverse effects of an oil price shock similar to those of the 1970s may be less today but severe nonetheless. As U.S. import dependence rises over time, the economic damage that would arise from a crisis inevitably increases.

U.S. Import Dependence Can Be Lessened, But at a Cost

Middle East OPEC contains about two-thirds of the non-communist world's conventional oil reserves (see Figure 4). About 400 billion barrels can be recovered from existing oil fields there. By comparison, the United States contains less than 5 percent of the total proved crude oil reserves, only 28 billion barrels (36 billion barrels of crude oil and natural gas liquids). Figure 4 also shows cumulative production levels, demonstrating the relative maturity of the development of U.S. oil resources.

Over 85 percent of all producing wells in the non-communist world are in the United States. As shown in Table 1, oil wells in Middle East OPEC are significantly more prolific producers, averaging almost 3,100 barrels per well per day from 3,000 wells, compared with an average of only 14 barrels per well per day from 650,000 wells in the United States. Even excluding the 460,000 stripper wells that produce less than 10 barrels per day each, average U.S. production per well is only 41 barrels per day. More significantly, the ratio of proved crude oil reserves per

TABLE 1

U.S. AND MIDDLE EAST OPEC OIL PRODUCTION STATISTICS

	Number of Producing Wells*	Average Daily Production* (Barrels Per Well)	Ratio of Reserves Per Producing Well* (Barrels)	Average Lifting Cost ($/Barrel)	Estimated Finding Cost ($/Barrel)
United States	650,000	14	44,000	$7.04†	$10.55†
Middle East OPEC	3,000	3,100	131,000,000	Less than $1.00	Less than $1.00

*DeGolyer and MacNaughton, *Twentieth Century Petroleum Statistics*, 1986.

†Arthur Andersen & Co., Oil & Gas Reserve Disclosures, 1981-85, Survey of 375 Public Companies.

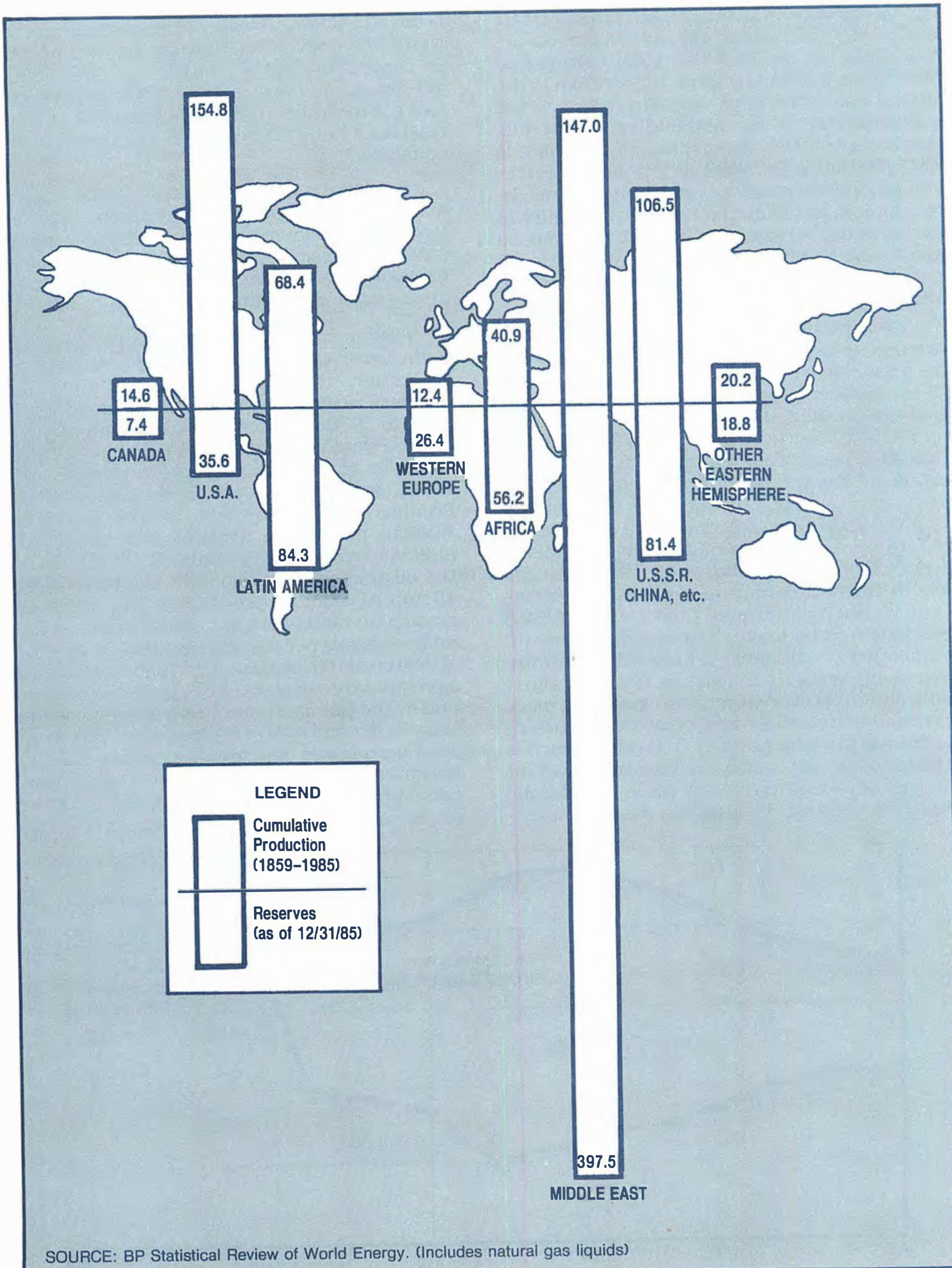


Figure 4. Total Discovered Oil (Billions of Barrels).

U.S. well is only 44,000 barrels versus a Middle East OPEC ratio of over 131 million barrels per well. On a per barrel basis, U.S. oil lifting and finding costs are many times higher than in the Middle East. The large disparity between the size of the reserve base and finding and production costs for these two areas allows the Middle East producers the flexibility to adjust prices and production policies to meet internal needs. In addition, based on the relative maturities of the oil and gas industries in the United States and in the Middle East, the United States will not be able to cut its costs to the levels of the Middle East.

Even though the United States has been extensively explored and drilled, it has substantial oil and gas resources remaining to be found. These resources, however, are relatively high cost and located either in smaller fields or in remote and hostile environments. In 1981, the United States Geological Survey (USGS) estimated that the U.S. oil and gas resource base includes about 100 billion barrels of oil and up to 700 trillion cubic feet of natural gas, in addition to proved reserves of 28 billion barrels of crude oil and 193 trillion cubic feet of natural gas. A follow-up study to the NPC Oil & Gas Outlook Survey indicated that the 1981 USGS estimate may be too high by about 30 percent. Part of these additional volumes will come from increasing recovery in existing fields, as about only one out of every three barrels of oil in place can be economically recovered with current technology. There are over 300 billion barrels of such oil in place today, and the development of more advanced technology could increase the resource estimate. Another significant resource is the 30 trillion cubic feet of natural gas on the North Slope of Alaska. Government and industry cooperation will be required to economically get this gas to market. In addition to these oil and gas resources, the United States' vast coal reserves amount to over a trillion barrels of oil equivalent.

Exploitation of these resources will require a significant investment in research, exploration, and development by the nation's energy industry. These investments will only be made if leasing, tax policy, and price projections justify such commitments.

As shown in Figure 5, crude oil production in the lower 48 states would have continued to decline after the mid-1970s without the drilling response to higher prices. If the decline rate of 1970 to 1976 had continued, lower 48 oil production would have been 1.7 million barrels per day lower in 1985. In addition, during the late 1970s, significant oil production started from Prudhoe Bay in northern Alaska. In 1985, Alaskan production amounted to about 1.8 million barrels per day, or almost 20 percent of U.S. oil production. Without the additional lower 48 and Alaskan oil production, U.S. crude oil production would have been lower by almost 3.5 million barrels per day, representing 39 percent of total crude oil production in 1985. Ominously, a preliminary estimate of U.S. crude oil production by the Energy Information Administration shows a decline of over 7 percent, or 680 thousand barrels per day, from December 1985 to December 1986. Even if U.S. oil consumption had not increased in response to the lower prices, imports would have risen nearly 700

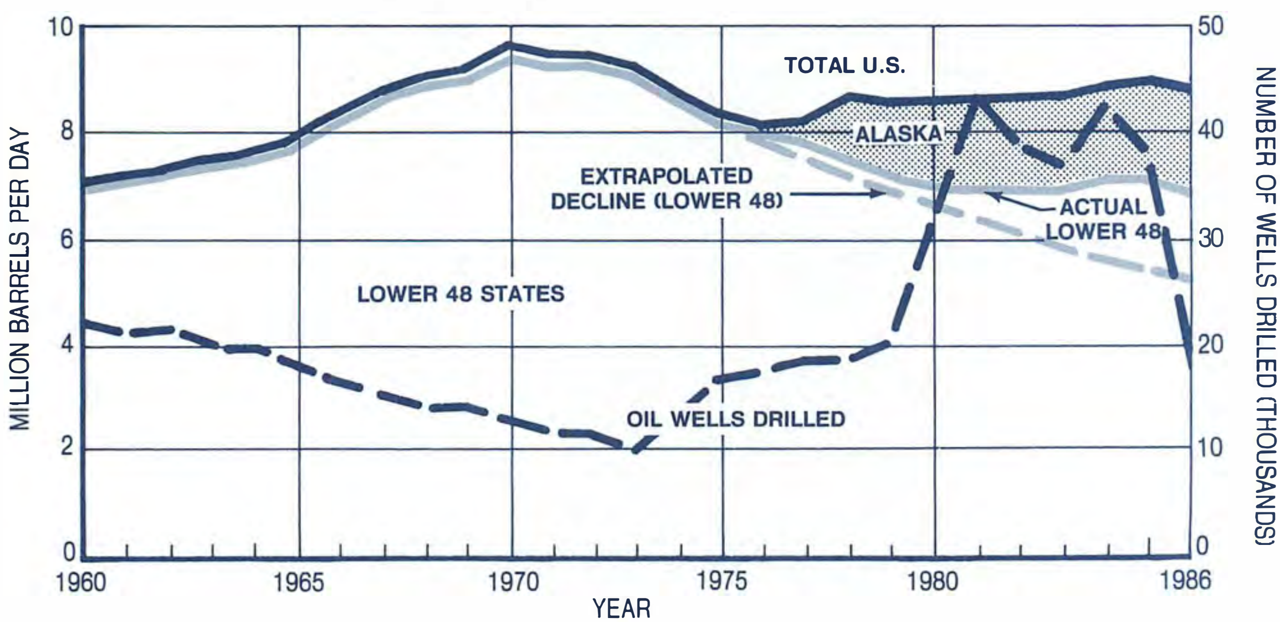


Figure 5. U.S. Crude Oil Production, Actual and Normal Decline, and Oil Wells Drilled.

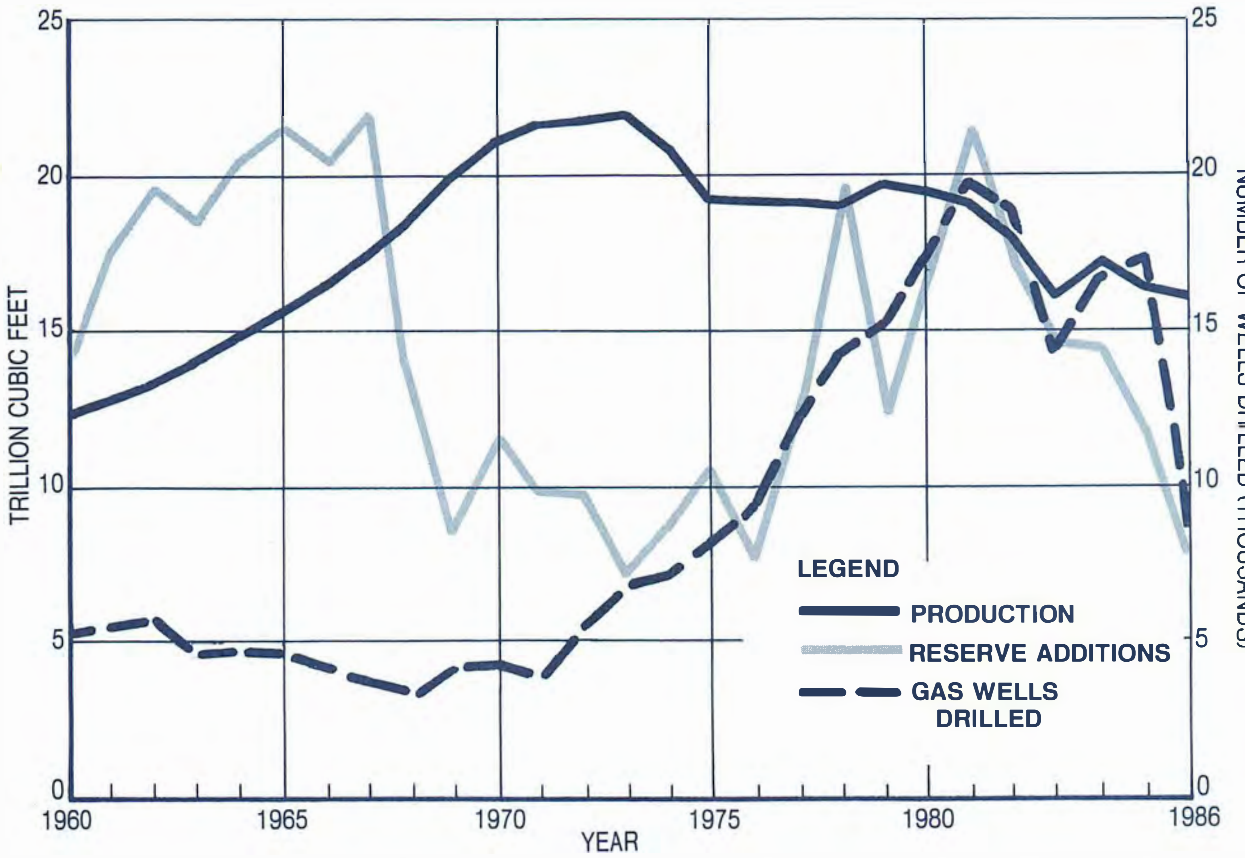


Figure 6. U.S. Natural Gas Production vs. Reserve Additions and Gas Wells Drilled (Lower 48 States).

thousand barrels per day just to make up for the decline in domestic production.

As with oil, domestic natural gas reserve additions respond directly to drilling activity (see Figure 6). In the late 1960s, the collapse in natural gas reserve additions, and ultimately in supply, occurred because the Federal Power Commission (FPC) kept average wellhead gas prices low even though gas exploration and development costs were rising. The low wellhead gas prices kept relative burnertip gas prices low, which caused demand to grow rapidly. By the early 1970s, potential gas demand exceeded available gas supplies, causing curtailments. In response to the curtailments, the FPC in the mid-1970s, and later the Natural Gas Policy Act (NGPA), allowed wellhead gas prices to increase, both of which caused drilling activity, and hence reserve additions, to grow significantly during the late 1970s and early 1980s.

The Domestic Petroleum Industry Faces Obstacles

Spending for exploration and development has been declining since 1981 due to the industry's lower cash flow, tax policy changes, the perception of lower future oil and gas prices, and the need to service the high debt incurred during the drilling boom. Oil industry operating cash flow in 1986 was estimated to be $34 billion, or 47 percent, lower than in 1985. In addition, because of the impaired industry profitability and reduced asset base, access to external financing has been seriously restricted. This has led to a reduction of $15 billion, or 36 percent, in estimated U.S. spending for exploration and development in 1986.

For those service companies and independent producers principally involved in exploration and production activities, the current environment has resulted in massive restructuring, consolidations, and bankruptcies. Already, a significant number of the service companies are out of business, and the total oil service sector had massive losses in 1986. The 110 publicly traded oil field service and equipment companies monitored by Simmons & Company had net losses of $5 billion. For exploration and development operations, cash flow is minimal; reserve values have fallen; and lenders are requiring accelerated repayment schedules. Many domestic independent oil producers and service companies cannot survive another year with oil prices remaining at or below 1986 levels ($15 per barrel). The survivors' capital expenditures for new reserves will be minimal.

The significant reductions in domestic exploration and production budgets and drilling activity have caused major layoffs in the petroleum industry. The domestic oil and gas extraction labor force fell from a high of 708,000 in 1982 to 570,000 in December 1985 and to 422,000 in December 1986. Eighty percent of the decline in employment from 1982 to December 1986 occurred in the oil field service sector. Drilling rigs operating in the United States dropped from a peak of 4,500 in 1981 to under 2,000 by the end of December 1985 and declined further to 700 by mid-1986. About 75 percent of currently operable rigs are now idle. In addition, undergraduate enrollments at many major U.S. universities in the critical areas of petroleum geology, geophysics, and engineering now stand at one-quarter of their early 1980s levels.

The time required to improve the industry's productive capacity will depend on both the depth and duration of reduced prices and other incentives, which determine the availability of investment capital, manpower, and equipment. This time lag, not just the reduction in exploration and production activity, will act to further increase U.S. energy vulnerability.

Oil and gas exploration and production is a long lead time business. An offshore project can easily take up to 10 years to advance from preliminary geological and geophysical work to initial production. An enhanced oil recovery project can take a similar length of time to move from preliminary engineering, through a test program, drilling injection wells and injecting fluid, to the beginning of tertiary production. Frontier areas, such as deep water Gulf of Mexico, which are believed to contain much of the nation's future oil and gas reserves, may require 10 or more years before production can commence. In Alaska, where there is also great potential, production can require 15 years or more to come on stream.

Another factor inhibiting oil and gas exploration is the closing of millions of acres of potential hydrocarbon-bearing federal lands to oil and gas exploration.

Concurrent with the downturn in oil prices, the oil industry is facing proposed environmental regulations that could exert a multibillion dollar impact on exploration and production activities. These proposals are focused on the classification and restrictions that may be placed on drilling fluids and cuttings, produced water, and associated wastes—both onshore and offshore. Preliminary industry estimates project that first-year costs could approach $20 billion, which is equivalent to $4 per barrel of the oil and natural gas produced annually, with an increase in annual operating costs of approximately $5 billion thereafter, which is equivalent to $1 per barrel of the oil and natural gas produced.

U.S. Government Energy Policies Can Play a Significant Role

The importance of petroleum to national security dictates that government must continually evaluate the recent trends in the supply of and demand for oil and gas, particularly in light of the impacts associated with historical supply disruptions and their consequent price shocks. Since the United States remains vulnerable to future disruptions, which could be of greater proportions than previous ones, government should carefully consider whether (and in what form) measures should be taken to alter these trends or otherwise reduce the nation's energy vulnerability.

In the longer term, the world oil market will become increasingly dependent on supplies from a few nations located in a geopolitically volatile part of the world—the Middle East. OPEC's decisions concerning the level of production will directly influence world price levels and will simultaneously impact the economic well-being of the nation and major segments of its industrial base.

The precipitous price collapse of 1986 presented the government with additional issues to consider. The price collapse has severely affected the oil and gas industry and reduced exploration activity dramatically.

Policy decisions or responses affecting strategic commodities like oil and gas often pit market forces against public interest considerations, most notably those affecting consumer costs and the environment. The reality of resource depletion and the concept of replacement cost pricing often conflict with political desires to insulate consumers from the effects of higher prices while trying to ensure that secure supplies of energy are readily available. Solutions have often been selected on the basis of short-term considerations, frequently at the expense of more desirable, longer-term objectives.

For example, selective exemptions in the late 1960s to the import quota program were granted to allow consumers the benefits of access to cheaper foreign oil, irrespective of the consequences of increased reliance on imports. The 1970s price controls on oil and gas limited production while encouraging demand and created inequities among industry participants. The entitlements program, in the interest of equalizing crude oil costs, also encouraged the importation of higher priced foreign oil. Consumer and environmental opposition to expanding nuclear and coal development produced increased dependence on oil.

Nonetheless, certain of the 1970s energy policies achieved their intended goals. The Carter administration's decision to gradually phase out price controls on domestic oil and the Reagan administration's subsequent acceleration of the schedule had the dual effects of minimizing the inflationary bite of higher oil prices while encouraging expanded drilling and production efforts. The development of a strategic petroleum reserve provides some supply and price protection in the event of a future supply disruption. The NGPA was directionally correct in its exploration and production incentives and in attempting to deregulate gas prices. However, its complicated price vintaging mechanism and the expansion of federal pricing controls to intrastate gas introduced other distortions into the gas market.

It is the purpose of this report to supply information to assess the implications of the oil and gas outlook and the options available to limit U.S. vulnerability. Should the government choose to act, it is likely that a mix of policies would be necessary to address the complex issues at hand. There is a range of policy options available to the government. Some are supply-oriented, others are demand-oriented; some address conventional fuels, others encourage the development and use of alternative fuels.

Further, there are numerous measures available to meet a given objective. For example, some focus on removing government regulations and restraints on the production and use of specific fuels, while others are designed to stimulate exploration and development activity. The choice among the options will rest on the time frame and the underlying economics of the targeted activity. Research into the long-term, not-yet-commercial use of some alternative fuels is likely to be conducted only at government expense, since the time frame in which those fuels will become economic is too protracted for standard corporate investment criteria. Research into more commercial technology, such as enhanced oil recovery, would likely respond to tax incentives. Incentives could tip the scale toward making the research investment economic.

The government's energy policy evaluation process must carefully weigh the relative efficiency of competing or complementary policy options. Generally, effective energy policies should achieve a given objective at the least overall cost and with the fewest unwanted side effects. Blunt policy tools, with widespread side effects, are less desirable than the sharper, more focused measures that can target an objective with more precision.

OPTIONS FOR CONSIDERATION

Chapter Nine contains various options that the government may consider. The options fall into two broad categories: those that have been considered for some time as viable options for the longer-term benefit of energy supply and demand in the United States, and those that have recently been considered as possible ways to counteract the significant effects of the recent price decline. By design, the effects of options in the latter category are shorter-term, but potentially they will have longer-term effects on the U.S. energy balance.

In reviewing the various options, government must evaluate the short-term and long-term impacts on oil and gas supply and demand and on the U.S. economy and environment. It is likely that no single policy will solve the complex national security problem. Disagreements among constituencies over what options are best for the nation will further complicate the choice.

Government policy in relation to environmental matters has not been included as an option since these regulations are directed at the desirable goal of preserving the environment. However, the government must consider the impact of all environmental actions and particularly the funding of such new measures on the vulnerability of the nation to a future energy crisis through a cost/benefit analysis.

Chapter Nine reviews the various policy options available to the government, setting forth their advantages and disadvantages. Following is a list of these options, which are not ranked in order of either priority or likelihood of implementation.

- Encourage greater access to federal lands with potential oil and gas resources, onshore and offshore, and improve the lease terms under which such lands are offered.
- Remove tax disincentives and use positive incentives to maintain existing production and to stimulate oil and gas exploration and development activity.
- Stabilize the price of oil by use of oil import fees at a level that will reduce consumption and stimulate domestic oil and gas production.
- Institute a floor price to guarantee a minimum price to oil producers that would maintain reasonable production and reserve levels.

- Promote research and development to increase the recovery of oil and gas already discovered, much of which cannot be produced economically with current technology, and develop the longer range technologies required to produce alternative fuels.
- Decontrol natural gas prices and markets by repeal of NGPA price controls on old gas, NGPA incremental pricing provisions, and the Fuel Use Act.
- Reduce demand by increasing the price of oil through consumption and excise taxes.
- Create incentives and mandates to continue energy conservation efforts.
- Encourage greater use of alternative fuels as substitutes for oil and gas.
- Diversify oil supply sources to reduce the likelihood that a disruption of a single source could precipitate a crisis.
- Pursue diplomatic policies that promote greater stability in the Middle East and Africa and greater interdependence with the United States.
- Expand and use strategic petroleum reserves to enhance the ability to limit the effects of supply shortages and price increases; the presence of such reserves reduces the likelihood of disruptions being used as a political tool.
- Develop fiscal and monetary policies that could be used to mitigate the impacts of oil price shocks, and could act to reduce the likelihood of oil supply disruptions.

In view of the importance of energy to the nation and the complexity of the security issues, every effort should be made to formulate these and other options that could conceivably satisfy the objectives of improved energy security.

Report Summary

THE 1970s ENERGY CRISES, POLICY RESPONSES, AND ECONOMIC EFFECTS

During the 1970s, the world experienced two severe energy crises resulting from the Arab oil embargo and the Iranian revolution. Other disruptions, including those associated with the closure of the Suez Canal in 1956 and the aftermath of the 1967 Arab/Israeli war (see Table 2), predated the 1970s crises. However, in these cases, the potentially devastating impacts of the supply shortfalls were largely offset by the existence of excess oil productive capacity outside of OPEC, particularly in the United States. The combination of the downturn in U.S. productive capacity after 1970 and increasing noncommunist world consumption (especially in the United States) increased reliance on oil imports from Middle East OPEC significantly.

1973–74 Arab Oil Embargo

OPEC was founded in 1960. Despite the desire of its members to control the production and pricing of their oil resources, the cartel lacked power in the early years, in part due to the presence of spare productive capacity in the United States and in part because of the member countries' reliance on the international oil companies to produce the oil.

By the end of the 1960s, the combination of growing demand for oil and the rich resource potential of the Middle East shifted the market advantage to OPEC. By 1970, U.S. crude oil production had peaked and the nation had become a major importer of both crude oil and refined petroleum products. The loss of domestic "surge" capacity and the growing inability of the United States to supply its allies in the event of a disruption further shifted the market advantage to the Middle East producers.

In response to rapid economic growth between 1950 and 1970, the demand for oil in the United States and the remainder of the noncommunist world was fast outpacing available new supplies (see Figures 7 and 8). Domestic consumption of petroleum increased by 50 percent (from 6.5 to 9.8 million barrels per day) between 1950 and 1960 and then again by 50 percent (to 14.7 million barrels per day) by 1970.

In October 1973, following the resumption of the Arab/Israeli war, eleven Arab nations immediately announced their intention to cut oil exports to any country that aided Israel. When the U.S. government resupplied Israel with weapons and spare parts, the Arab producers responded with a targeted supply embargo against the United States and others.

The production curtailments resulting from the embargo reduced Arab oil supplies worldwide by approximately 5 million barrels per day. After accounting for the increased output from other producers, the shortfall was about 4 million barrels per day, or 7 percent of pre-embargo consumption.

TABLE 2

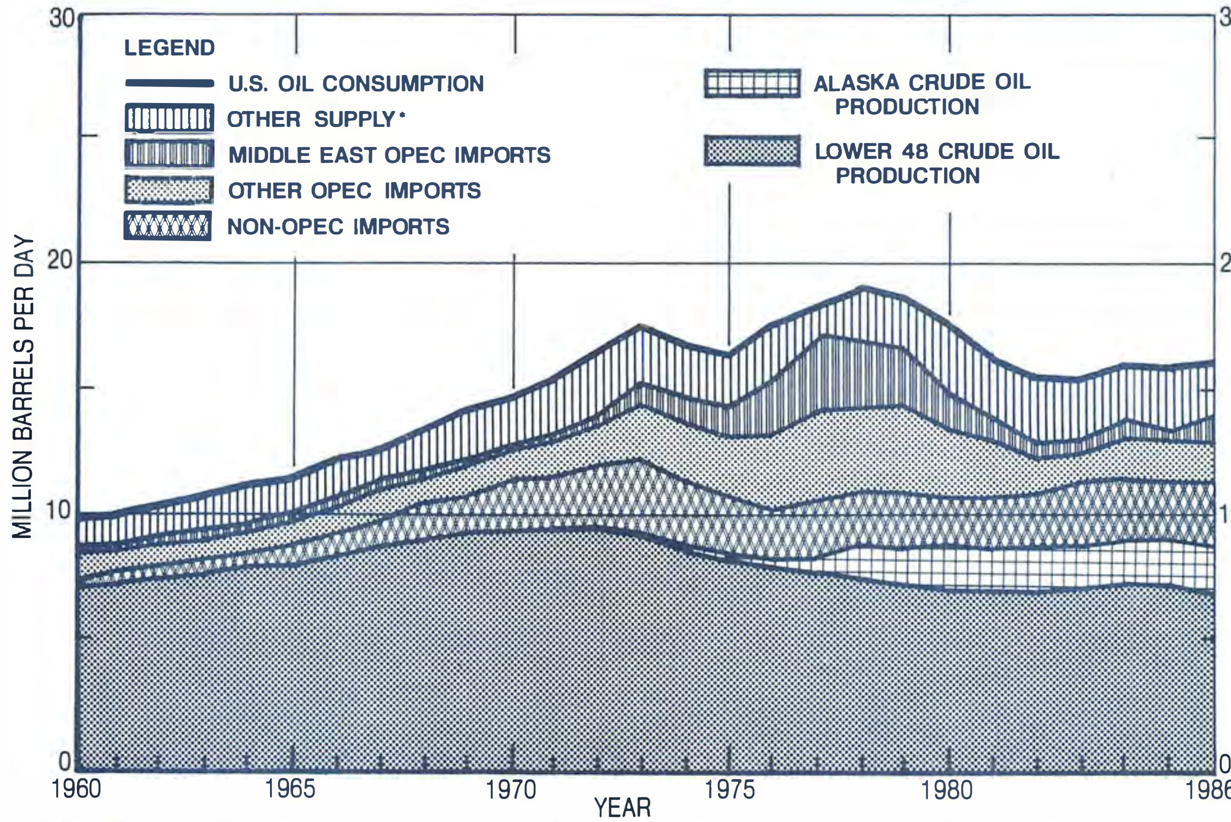
HISTORY OF OIL SUPPLY DISTURBANCES AFTER WORLD WAR II

Event/Date	Volume Impact	U.S. Price Impact	How Accommodated
Iranian Nationalization of British Petroleum (BP) Concession 1951	Iran production of 0.7 million barrels per day (MMB/D) (7% of free world production) shutdown almost completely until 1954.	None	Shortfall offset by higher liftings primarily from Iraq and Kuwait. Iran tried to sell oil but could not find buyers.
Suez Crisis 1956–57	Canal closed November 1956 to March 1957. Movement of 1.5 MMB/D through canal, 0.5 MMB/D through Iraq Petroleum Company (IPC) pipelines stopped. (13% of free-world production affected.)	U.S. crude oil prices raised $0.25 to $0.45 (10%) per barrel in January	Shipments increased 0.7 MMB/D to Europe from Western Hemisphere, 0.9 MMB/D moved around Cape and tankers in tight supply. Rationing, stock drawdown occurred in Europe. Coincided with mild winter and general decline in industrial activity.
June War 1967	Suez Canal, Tapline, IPC pipelines closed June 6. Production shut down June 6–14 in all Arab countries except Abu Dhabi, Qatar, Algeria. Production resumed by Iraq end of June, Libya first week of July. 5 MMB/D affected (17% of free-world production).	U.S. crude oil prices raised $0.05 to $0.07 (2%) per barrel in August	U.S. offset shortfall. Tanker fleet larger, more flexible. Disruption occurred during seasonal low.
Arab Oil Embargo 1973	Arab production fell 5 MMB/D from October to December (10% of free-world production).	Price increased from $3 per barrel to $12 per barrel	End of surplus productive capacity outside OPEC. Price and allocation controls in U.S. inhibited demand response. Substantial inventory build.
Iranian Revolution 1978	Iranian production fell 3.6 MMB/D from September to December (7% of free-world production).	Spot price reached $30 per barrel	Saudi Arabia initially accommodated but then cut back. Price and allocation controls on gasoline inhibited demand response and resulted in misallocation of supplies. Substantial inventory build.
Iran/Iraq War 1980	Iraq production fell 2.7 MMB/D, Iranian production fell 0.6 MMB/D (7% of free-world production).	Spot price reached $43 per barrel but then declined sharply	Demand was declining, non-OPEC production capacity growing, disrupted production not needed.

Government Response to 1973–74 Arab Oil Embargo

In 1971, in an attempt to control spiraling inflation, the Nixon administration implemented Phase I of the wage and price control program. The price freeze had the dual effect of discouraging domestic exploration and production while simultaneously promoting increased energy consumption.

By late 1972, spot shortages began to appear throughout the United States. To alleviate the shortages, the federal government responded with a voluntary petroleum allocation program, which shortly thereafter became a congressionally mandated program. By the fall of 1973—just prior to the onset of the embargo—domestic oil consumption had reached over 17 million barrels per day. The United States was relying on foreign oil to meet approximately 35 percent of its petroleum needs. When the embargo was imposed in October of 1973, the allocation scheme, which had been constructed to handle the pre-embargo



*Natural gas liquids, net imports from communist countries, refinery gain, inventory change, tar sands, shale, and synthetic fuels.

Figure 7. U.S. Oil Supplies.

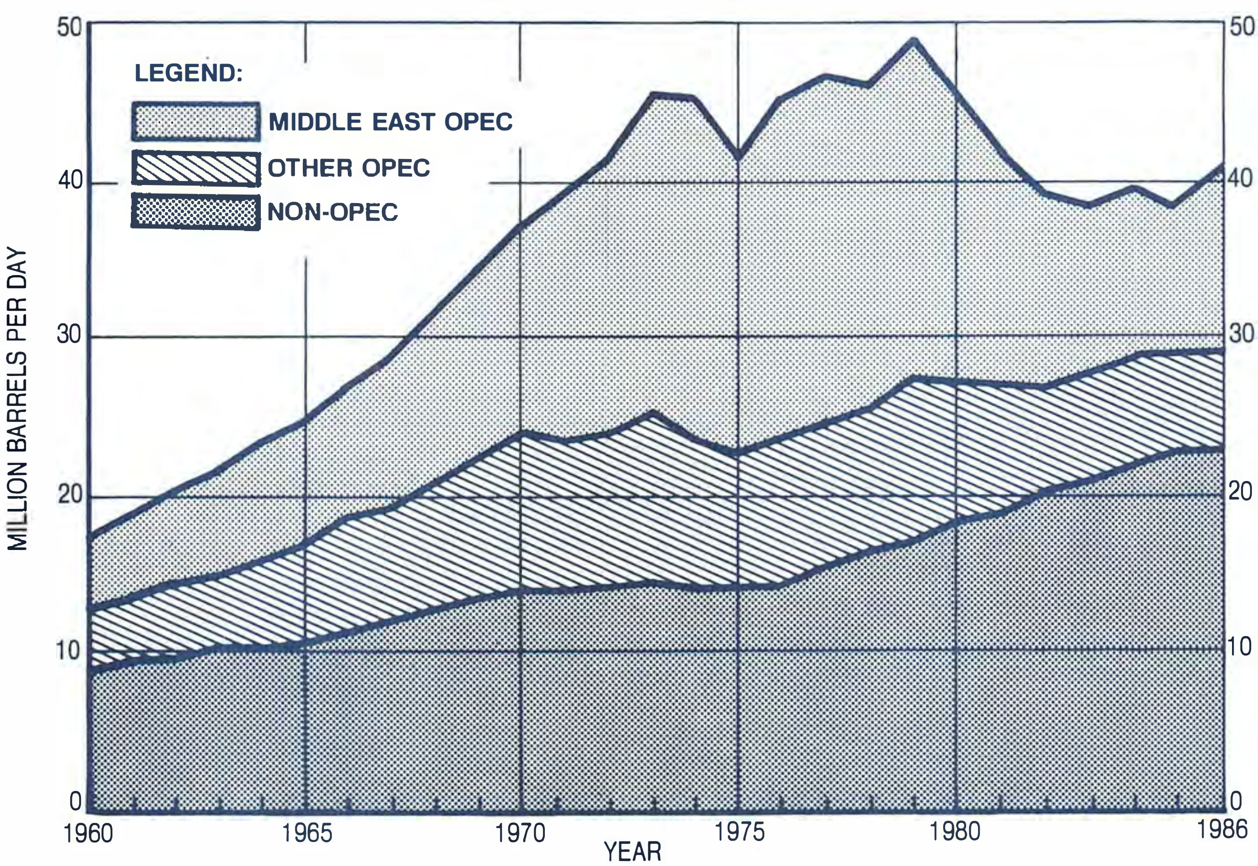


Figure 8. Non-Communist World Crude Oil Production.

shortages, was hastily superimposed to address the embargo situation.

Ironically, the allocation regulations were perceived by the government as a means to correct problems created by the price controls. Despite this intent, the regulations only served to further distort the operation of the marketplace and exacerbate the shortage.

As a political matter, the shortages underscored the call for the allocation regulations, and contributed to the decision to extend price controls for the oil industry for many years after the freeze was lifted for all other sectors of the economy. This extension compounded the price disparity between price-controlled domestic oil and uncontrolled foreign oil.

Despite the intent of protecting and insulating consumers from the effects of significant energy price increases, the price and allocation measures were a disincentive to exploration and production activity and discouraged conservation and fuel efficiency. Consequently, energy consumption and import reliance continued to increase.

1978–79 Iranian Revolution and Aftermath

Between 1973 and the onset of the Iranian revolution in 1978, U.S. crude oil production declined by almost a million barrels per day. Domestic gas production also declined by 10 percent. Over this period, U.S. dependence on foreign oil continued to grow from 35 percent to 46 percent of consumption. Drilling had increased almost 100 percent in response to higher oil prices, but the long decline in oil production in the lower 48 states would not be arrested until 1979 (see Figure 5).

The Iranian revolution resulted in a precipitous decline in Iran's oil output and exports. The loss of Iranian oil during the November 1978–June 1979 period was partially offset by increased production elsewhere in the world. Although the resulting loss of world oil supplies during the revolution was 2 to 2.5 million barrels per day, the U.S. share of the total supply shortfall was only about 200 to 400 thousand barrels per day.

A shortfall of this magnitude should have produced only minor disruptive effects, certainly not a tripling of oil prices. The convergence of a variety of factors, however, produced a rapid increase in spot prices. These factors included U.S. price and allocation controls, low pre-crisis inventory levels, uncertainty regarding the duration and magnitude of the crisis, the curtailment of third party sales, and consumer panic buying. Between October 1978 and the end of the year, Rotterdam spot market prices for crude oil doubled, from $10.50 to over $22 per barrel. From the first quarter of 1979 to the first quarter of 1981, average OPEC oil prices increased by 170 percent, from about $13 to over $35 per barrel.

Panic buying was not limited to consumers alone. Major industrialized nations (e.g., Japan) that had been particularly dependent on Iranian oil supplies also became active in the spot market, bidding up prices for crude oil and product cargos.

Government Response to the Iranian Crisis

In April 1977, President Carter unveiled the National Energy Plan. The goals of the plan were to reduce energy demand and cut oil imports through conservation, fuel switching, synthetic fuels development, and new pricing regimes for oil and gas.

At the outset of the Iranian crisis, the administration attempted to minimize the shortfall by encouraging a variety of conservation measures. However, the statutory extension of price controls undermined the conservation efforts and discouraged investments to bring on additional domestic supplies.

In anticipation of a protracted shortage, the administration also urged refiners to use their inventories sparingly and to rebuild stocks. The cumulative effects of these decisions and the various "quirks" of the allocation regulations were at least partly responsible for the gasoline shortages that developed over the next four months.

Gasoline lines first surfaced in California in the spring of 1979. The phenomenon was subsequently observed in various locations throughout the nation, primarily in metropolitan areas. Surpluses continued to exist in rural, resort, and farm areas. The hidden culprits behind the gas lines were the allocation regulations and "tank topping" by panicked consumers.

Crude Oil Decontrol

In April 1979, in the face of political opposition and rising world oil prices, President Carter announced a program of phased decontrol. Controls on domestic oil were gradually lifted over a 30-month period in order to minimize both the inflationary impacts and the increased costs to consumers. Under the proposal, all controls were to be eliminated by October 1981.

In 1980, Congress enacted the Crude Oil Windfall Profit Tax, a measure widely recognized as the political "quid pro quo" for decontrol. In January 1981, President Reagan terminated the remaining controls on domestic oil, accelerating by 8 months the phaseout schedule begun by President Carter almost two years earlier.

The Natural Gas Curtailments of the 1970s

Government regulation was also a major contributor to the natural gas shortages of the mid-1970s. Low, regulated prices, the lack of competitively priced alternatives, the rapid expansion of the gas distribution network and service hookups, and environmental regulations on other fuels all contributed to a rapidly increasing demand for natural gas. A growing price disparity between sales in the price controlled interstate and uncontrolled intrastate markets caused a disproportionate amount of new gas to be dedicated to the intrastate system. The resulting shortfall caused widespread interruptions and curtailments for interstate customers.

As shortages spread throughout the nation, curtailments by pipeline companies grew rapidly, leading to some switching to higher cost fuel, plant closings, and worker layoffs. In February of 1977, every school in Pennsylvania was closed. Thousands of factories along the east coast were shut down. States from New York to Minnesota to Tennessee proclaimed emergencies. When curtailments were no longer temporary nor limited to interruptible customers, the Federal Power Commission was forced to devise some criteria for "rationing" available supplies.

Congressional responses to the worsening gas shortage in the interstate market led to the enactment in 1977 of the Emergency Natural Gas Act and the subsequent enactment of the NGPA in 1978. Under the NGPA, wellhead prices for certain categories of gas were to remain controlled until produced and depleted. In addition, the Act brought intrastate gas under federal regulation for the first time. Through the use of incentive and market pricing for selected categories of new gas and assisted by rising oil prices, the Act stimulated additional drilling for new and higher cost gas.

In reaction to higher oil prices and in anticipation of the removal of price controls, domestic oil and gas producers responded with record drilling in 1980 and 1981. As a result of this record drilling—coupled with declining gas demand—excess deliverability, or a gas bubble, developed.

Economic Impacts of 1970s Energy Crises

The events of the 1970s demonstrate that the price and availability of energy, and in particular oil and gas, play a significant role in determining the overall performance of the U.S. economy. Because energy costs are a pervasive component of total manufacturing and distribution costs, changes in energy prices affect the prices of most goods and services. Energy is also an important element of personal consumption expenditures. Consequently, changes in energy prices affect the amount households can spend on other goods and services. These impacts are compounded by the importance of energy in U.S. international trade and the associated wealth transfers between the United States and oil-exporting countries.

When each of the 1970s energy crises occurred, the U.S. economy was booming, unemployment was low, inflation was accelerating, and interest rates were high. In each case, most economic forecasts projected a mild recession the following year. Instead, the U.S. economy suffered its two worst post-war recessions during the 1973–75 and 1980–82 periods.

In order to determine to what extent rising oil prices contributed to the 1973–75 and 1980–82 recessionary periods, a model was used to simulate the U.S. economy absent the oil price shocks of 1973 and 1979.[2] Monetary and fiscal policies were held constant in order to isolate the impact of the price shocks. That part of the recessions not attributable directly to the oil price shocks was largely due to these policies, which may indeed have been influenced by the oil price shocks.

The model results indicated that the cumulative economic effects of the oil price shocks grew strongly for about two years before leveling off after three years. Estimates of the impact on GNP and unemployment are summarized in Figures 9 and 10.

Figure 9 indicates that the 1973 and 1979 energy price increases shrank the U.S. economy by approximately 2.5 percent and 3.5 percent, respectively. The 1979 case shows a greater impact relative to the 1973 case because the price increases were larger and the level of oil imports was higher. The level of business fixed investment was reduced about 7 percent by

[2]The model used was the Wharton Econometric Forecasting Associates Mark 8 model.

each of the 1970s price shocks. In today's economy, each percent reduction in GNP would mean about a $40 billion reduction in the value of goods and services produced in the United States.

Reduced economic activity and business investment have a critical effect on jobs. As Figure 10 indicates, the 1973 and 1979 oil price shocks increased the unemployment rate by approximately 1.5 and 2 percentage points, respectively. In today's economy, each percentage point increase in the unemployment rate would mean the loss of over 1 million jobs.

Inflation, as measured by the rate of change in the Consumer Price Index, jumped by about 3 percentage points in the first year after each energy price shock. After the 1973 shock, the inflationary impact subsided to an average of about one percentage point in the second and third years following the shock. After the 1979 shock, the impact subsided much more slowly, leaving the inflation rate in the third year almost 2 percentage points higher than it would have been in the absence of the shock. Differences in patterns between the 1973 and 1979 cases reflect different rates of oil price escalation, different monetary policy responses, and the status of price controls.

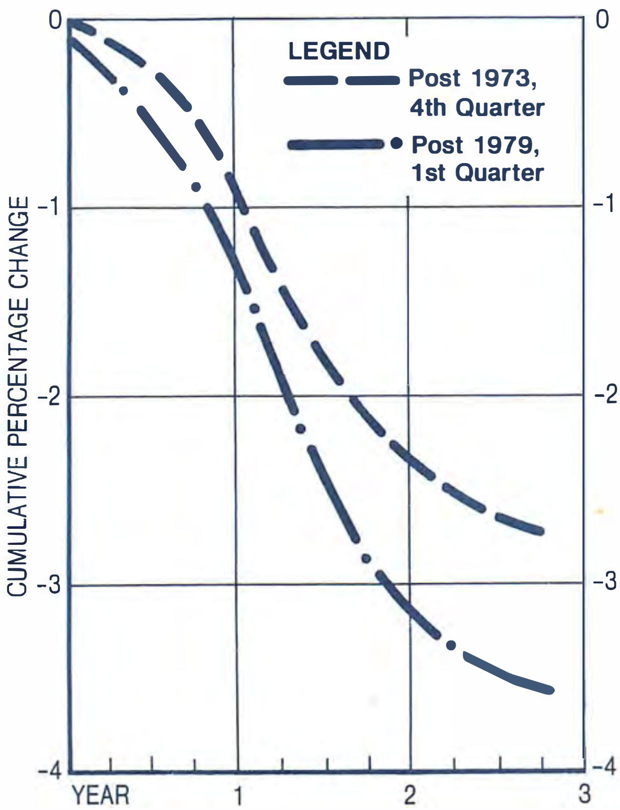


Figure 9. Impact of Oil Price Shocks on Real GNP, in 1982 Dollars.

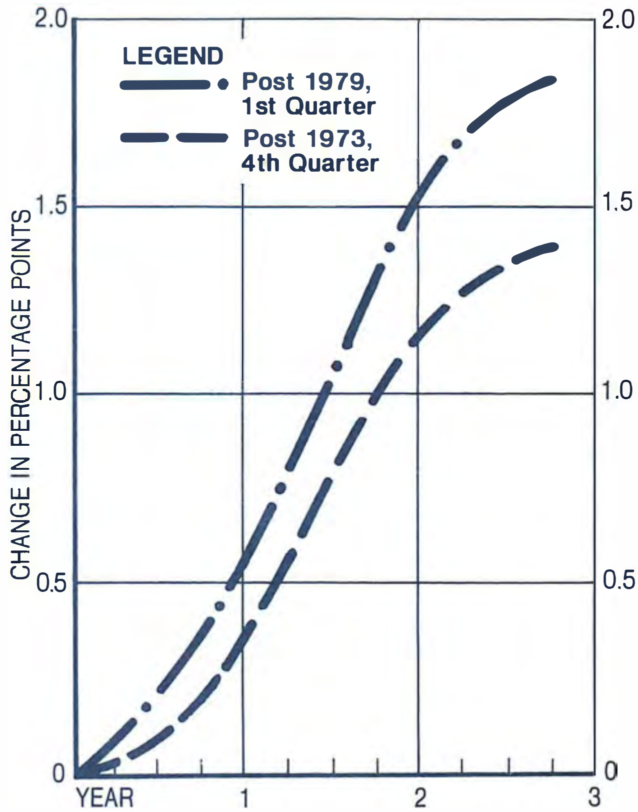


Figure 10. Impact of Oil Price Shocks on Unemployment Rate.

ECONOMIC IMPACTS OF FUTURE ENERGY CRISES

It is difficult to predict the impact on the U.S. economy of future oil supply disruptions and price shocks. The precise costs to the U.S. economy will depend on:

- Size of the crisis
- Timing and duration of the crisis
- Overall energy and oil intensity of the economy
- Level of dependence on imported oil
- Capability of the domestic energy industry to increase production during a crisis
- Availability of and capability to utilize alternative domestic energy sources
- State of the economy at the time of the crisis
- Government's fiscal, monetary, and energy policy responses, including the availability and release of strategic petroleum reserves
- Petroleum stock changes in the United States and other oil-consuming countries.

Using history as a guide, even a modest crude oil supply disruption can cause significant price changes that, in turn, have dramatic effects on the economy. Because the energy intensity of the U.S. economy has been reduced since the 1970s, the economic costs of an oil price increase similar to those of the 1970s could be less today but nevertheless severe. As U.S. import dependence inevitably rises over time, the potential economic damage that would result from a crisis similar to those of the 1970s will increase.

THE 1986 OIL PRICE COLLAPSE

Impact on U.S. Petroleum Exploration and Production

In December 1985, OPEC decided to increase its market share. The world's oil market could not absorb the increase in production and prices fell from about $27 per barrel in December 1985 to less than half that level by mid-year 1986. The price fell as low as $10 per barrel before stabilizing in the fall at about $15 per barrel. By year-end, following OPEC's decision to return to a fixed price system, the price had risen to about $18 per barrel.

With the precipitous drop in oil prices, U.S. petroleum exploration and development budgets were slashed. Drilling has fallen drastically, reserves and production are declining, and the productive capacity of the industry is being seriously impaired. These events are accelerating the growth of U.S. dependence on oil imports and could lead to another serious energy crisis.

Figure 11 shows the petroleum industry's U.S. expenditures to find, develop, and produce oil and natural gas. These expenditures do not include federal and state income taxes, dividends, and interest payments. Figure 12 plots the average U.S. wellhead oil price. Both the increase and decrease of industry spending correspond closely with oil price changes. Spending for exploration and development has been declining since 1981 due to the industry's lower cash flow and perception of lower future oil and gas prices. Oil industry operating cash flow in 1986 was estimated to be $34 billion, or 47 percent, lower than in 1985. This has led to a reduction of $15 billion, or 36 percent, in U.S. spending for exploration and development.

The IPAA/SIPES Drilling Survey was sent to the independent producers and petroleum technical specialists responsible for the investment and drilling decisions for the majority of the oil and gas wells drilled in the United States. Respondents were requested to estimate their level of drilling activity for each of the next five years assuming 1985 drilling costs and average oil and gas prices of $13 per barrel and $1.30 per thousand cubic feet, respectively; $20 per barrel and $2.40 per thousand cubic feet; and $27 per barrel and $3.50 per thousand cubic feet. The first two oil price assumptions approximate the 1986–90 prices of the lower and upper price trends, respectively, of the NPC Oil & Gas Outlook Survey described below. The $27 price assumption was selected as representative of the price levels experienced by the industry prior to the recent severe price decline.

At an oil price of $13 per barrel, the survey respondents expect their drilling to decline to 18 percent of the 1985 level in 1987 and to further decline to 15 percent in 1990. At a price of $20 per barrel, drilling would fall to half the 1985 level by 1987 and remain at that level through 1990. Finally, at $27 per barrel, drilling would increase about 7 percent by 1987, then increase steadily to about 124 percent of the 1985 level in 1990.

In March 1986, the American Petroleum Institute (API) surveyed 21 large integrated petroleum companies on the effect of lower prices. Like the IPAA/SIPES Drilling Survey, the results of the API Crude Oil Price Effects Survey indicate that there would be a sustained decline in drilling activity under low price scenarios. The API survey indicates that well completions would be 31,100 in 1991 under a constant $15 per barrel scenario (1985 dollars), a decline of 60 percent; and 12,500 under a $10 per barrel scenario, an 80 percent decline. The API survey respondents projected relatively unchanged drilling activity (73,400 completions in 1991) had prices stayed at the 1985 level of $28.

As shown in Figure 13, there is a close correlation between crude oil prices and the number of rigs actively drilling for oil and natural gas in the United States. For the year 1981, drilling rigs operating in the United States averaged nearly 4,000, with a peak of 4,500 in December 1981. By 1985, the count was below 2,000, and declined further to below 700 by mid-1986 before rising to 988 by year-end. About 75 percent of currently operable rigs are now idle. The significant reductions in domestic exploration and production budgets and drilling activity have caused major layoffs in the petroleum industry. The domestic oil and gas extraction labor force fell from a high of 708,000 in 1982 to 570,000 in December 1985 and 422,000 in December 1986.

It took five years of drilling an average of over 80,000 wells annually to maintain oil production and gas deliverability. However, in 1984, the United States replaced about 80 percent of

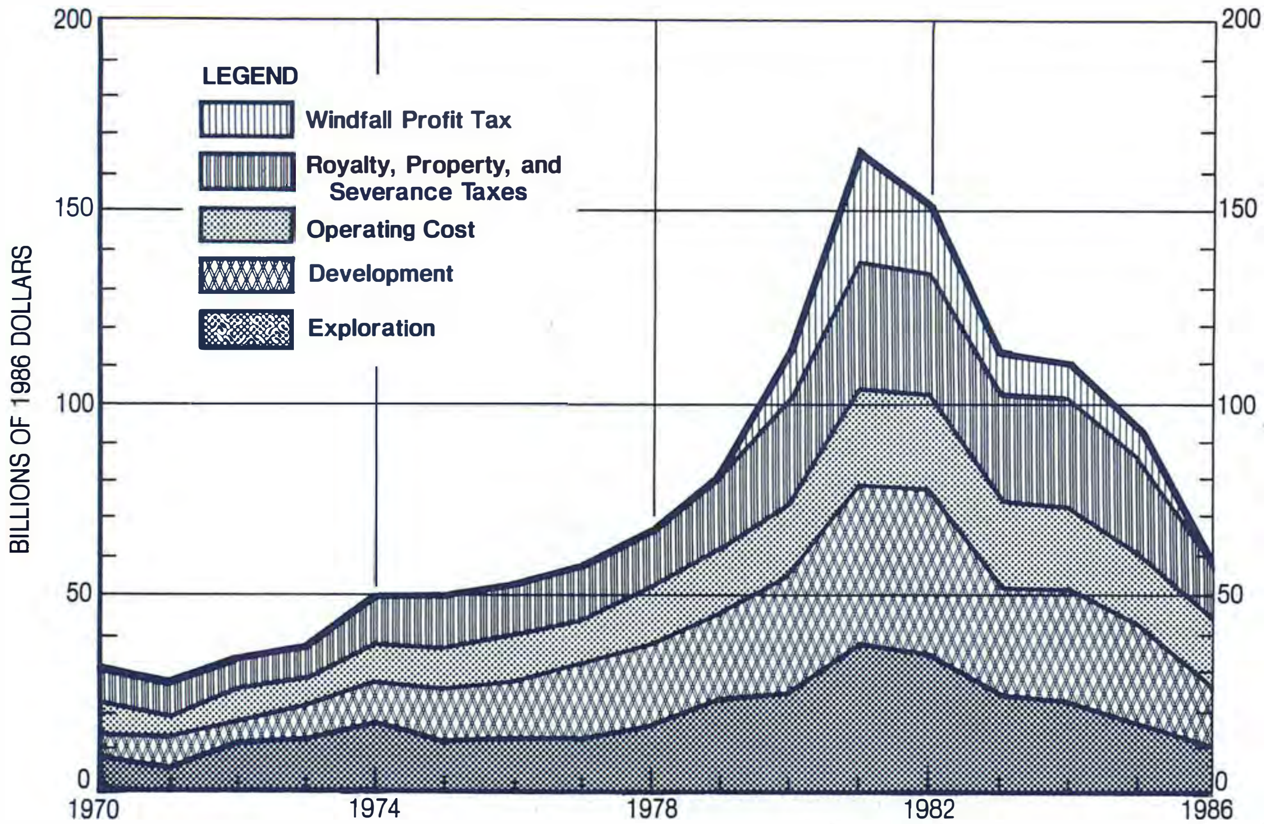


Figure 11. U.S. Exploration, Development, and Production Expenditures (Constant 1986 Dollars).

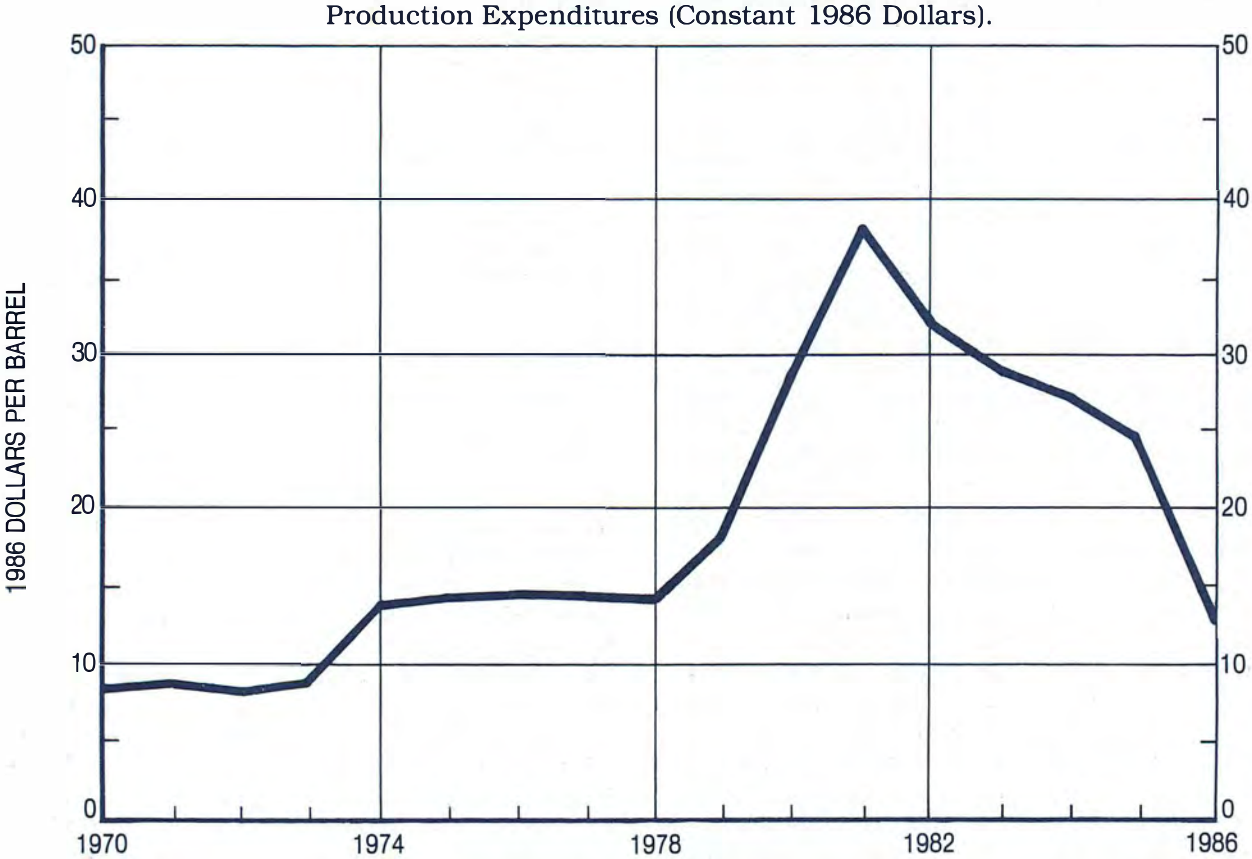


Figure 12. Annual Average U.S. Wellhead Oil Price (1986 Dollars per Barrel).

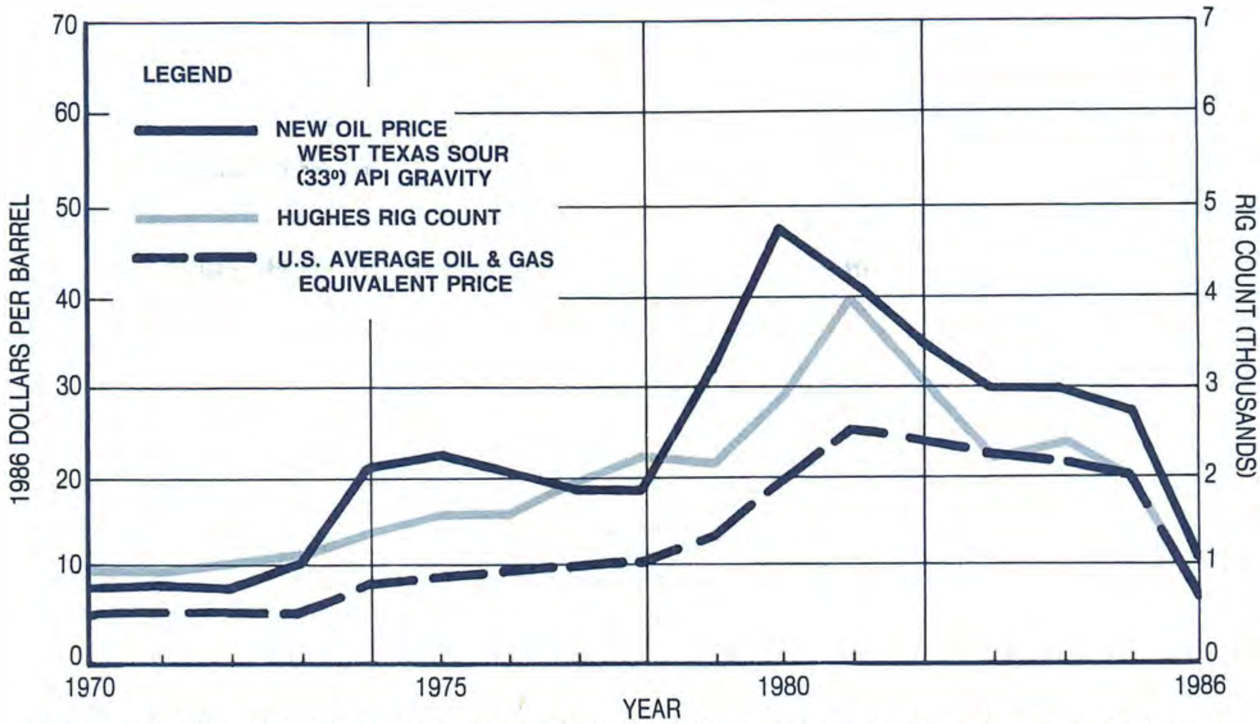


Figure 13. U.S. Wellhead Crude Oil and Natural Gas Price vs. Drilling Rig Activity Levels.

the gas it consumed; in 1985, replacement was only about 70 percent of consumption; and the 1986 level of drilling activity indicates less than one-half the gas used was replaced by new reserves found. As drilling remains depressed, fewer reserve additions will be added and production will continue to decline.

The reductions in the level of exploration and production activity brought on by a sustained period of lower prices and reduced cash flow cannot be quickly reversed. As noted earlier, oil and gas exploration and production is a long lead time business, with 10 to 15 years required for exploration and development in offshore, frontier, and hostile areas. The price declines have significantly reduced the willingness and ability of external sources (banks, insurance companies, and publicly raised funds) to support the industry. Banks and other lending institutions find themselves with a number of problem energy loans in their portfolios.

Significant capital for new project financing will be available again when the lending institutions have rebuilt their confidence in the profitability and stability of the industry. Investments by private and public drilling and acquisition funds, a major source of capital for independent producers, have declined 92 percent from a high of $4.0 billion in 1981 to $0.3 billion in 1985. Future capital from these sources will be restricted by the adverse impacts of the Tax Reform Act of 1986. In the absence of outside capital, the petroleum industry will be restricted to its depressed internal cash flow for investment in new exploration and development projects.

In this regard, the provisions of the Tax Reform Act of 1986 that inhibit capital formation, e.g., loss of the investment tax credit and lengthened depreciation schedules, will undermine the industry's ability to generate cash. Further, changes to the treatment of intangible drilling costs and the perverse effect of the minimum tax will encourage producers to liquidate their assets rather than reinvest in ventures searching for oil and gas. The API estimated that the Act will increase the petroleum industry's taxes by $10 billion over the 1986–91 period.

While the recent oil price decline has affected all segments of the industry, it has been particularly onerous for the oil field service industry. Eighty percent of the recent increase in unemployment in the oil and gas extraction industry has occurred in this area. Equipment is being lost, either through lack of maintenance, cannibalization, or liquidation. Skilled and professional personnel with years of training and experience are unemployed or moving to other industries. Any future increase in the demand for oil field services will require the service and supply industry to be rebuilt. Experienced personnel will have to be enticed back at a premium to an industry they view as volatile. These factors will add to the economic cost of an oil price increase because of the time lag in industry's response.

States such as Texas, Alaska, Louisiana, and Oklahoma rely heavily on severance and production taxes and royalties to finance their budgets. These states are having to cut back on spending and look elsewhere for new revenues. Foreign countries such as Mexico, Egypt, Nigeria, and Indonesia are having trouble making the interest and principal payments on loan obligations. These adverse consequences are raising new concerns about the longer-term impact of low oil prices.

There is no question that depressed conditions in the petroleum industry will affect the long-term welfare of the nation. Until the economics of oil and gas exploration improve appreciably through increased price, reduced taxes, or other incentives, U.S. exploration will remain stagnant, dependence on imports will increase more rapidly, and the nation's vulnerability to oil price and supply shocks will rise to an excessively dangerous level. All of this will seriously affect the nation's security and economic stability.

Impact on the Economy

Although some near-term economic benefits are being experienced as a result of the oil price decrease, the increase in consumer real disposable income and the lower inflation rate have been partially offset by the reduced capital spending in the petroleum industry. Because of the time lag, the full economic benefits of lower oil prices will not be felt until considerable time has passed.

There are several reasons why these positive economic effects of declining prices will be considerably smaller in magnitude, and slower to occur, than the negative impacts of the 1970s price increases. Because of conservation efforts, improvements in energy-use technology, and the growth of the service sector relative to the manufacturing sector, the U.S. economy is less energy-intensive than it was in the 1970s. As a result, energy price movements, either positive or negative, have smaller economic impacts today than they did then.

Furthermore, adjustments to changing economic conditions are never instantaneous and without cost. Regardless of whether prices rise or fall, costs are incurred in adjusting to the new price level. Eventually, however, a sustained period of lower oil prices can be expected to result in an increase in the overall level of economic activity.

In 1986, rising U.S. oil demand and falling production due to lower oil prices resulted in a 23 percent increase in the volume of 1986 net oil imports. Although the cost of imported oil will be lower, the net oil import bill will still amount to about $30 billion in 1986 versus $45 billion in 1985. Oil imports represented the single largest item in the U.S. international trade accounts in 1985. With import volumes expected to rise, the oil import bill would increase very rapidly if prices return to 1980–85 levels.

To ensure their future, energy companies must reinvest a substantial portion of their cash flow to replace oil and gas produced from their depleting reserve base. An Arthur Andersen & Company study of 375 U.S. public oil and gas companies during the 1981–85 period revealed that the industry's average "plowback ratio" or capital reinvested from cash flow for new domestic reserves averaged 70 percent of cash flow from exploration and production operations.

Operators other than the major integrated companies are thought of as the independent sector, even though companies such as pipelines, utilities, and diversified corporations are also involved in exploration and production. These operators drill 85–90 percent of the wells in the United States each year and find about 50 percent of the oil and gas reserve additions.

The Arthur Andersen data on the non-integrated "independent" producers show that, during the 1981–85 period, the companies studied had an average plowback ratio of 106 percent. The independents' plowback ratio exceeded 100 percent during the early 1980s, when oil prices were high, due to their investing a greater amount than their cash flow by incurring debt. However, many of these independent oil operators are now going out of business as a result of the lower oil prices.

The smaller companies concentrate their activities in the lower-48 onshore regions, where the finding rate has fallen substantially in the last decade, and where drilling rates must remain high to maintain reserves. The large integrated companies, on the other hand, with higher success and finding rates, have been important in the high risk (and potentially high reward) offshore and frontier areas.

Today's oil and gas production volumes reflect the high oil and gas prices of the late 1970s and the first half of the 1980s. These prices encouraged borrowing and generated revenue that was plowed back into exploration and development. The drilling boom of the late 1970s and early 1980s was fed by the expectations of ever-rising oil and gas prices.

Conversely, decisions not to invest because of today's low prices have an immediate negative impact plus a delayed effect that will not be visible for years to come. When prices begin to rise, investors may react slowly, waiting until they can evaluate the upward price trend as sustainable.

Also, to be profitable, the value of the new reserves discovered must be greater than the amounts expended. During the same five-year period, 1981–85, the 375 companies surveyed by Arthur Andersen incurred costs for exploration and development averaging $10.55 per net equivalent barrel. When operating costs, royalties, and taxes are included, crude oil prices at the levels prevailing in 1986 are inadequate to achieve a reasonable earning level on the investments undertaken from 1981 to 1985. This disparity between today's low oil and gas prices and the price required to be profitable is the key to the industry's current depressed drilling levels.

SUPPLY AND DEMAND OUTLOOK

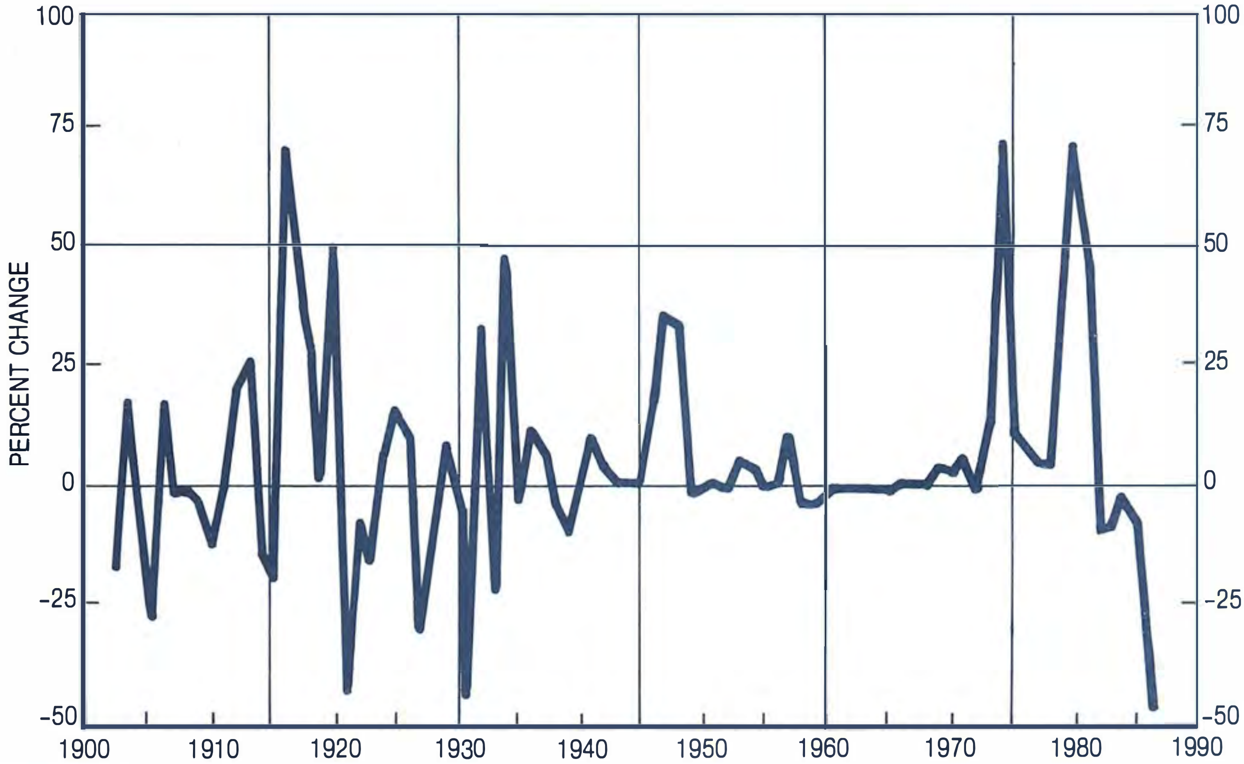
Although many factors, such as the resource base, technology, and government policies, influence the supply of and demand for oil and natural gas, the most important factor remains price.

Since its inception in the mid-1800s, the U.S. oil industry has been through many periods of price volatility. As shown in Figure 14, the annual percentage changes in oil prices between 1900 and the early 1930s rival those the world has been through since the early 1970s.

A major factor affecting price instability since the mid-1970s has been the shift of swing oil productive capacity to Middle East OPEC. During the 1970s, when OPEC's capacity utilization level moved above 80 percent, its members were able to increase prices and maintain them at high levels (see Figure 3). Subsequent to the second oil price shock, due to increases in non-OPEC energy supplies and the decline in world oil demand, OPEC's capacity utilization ultimately fell to such a low point that in late 1985 it opted to regain its market share rather than hold the price at former levels.

Price instability is difficult to cope with in the capital-intensive oil and natural gas industry, with the long lead times required for investment. This price instability and the resulting uncertainty represent an added risk that raises the expected return needed to justify an investment.

The world has experienced short-term oil price instability within longer-term oil pricing cycles. A trend toward lower real prices, as occurred in the 1950s and 1960s, carries with it the seeds of its own destruction and can result in a sudden price spike (see Figure 15). This is because, in a low price environment, investment in exploration and development usually falls



SOURCE: *Salomon Brothers*

Figure 14. Percent Change in Annual Average Crude Oil Wellhead Prices (Nominal Dollars per Barrel).

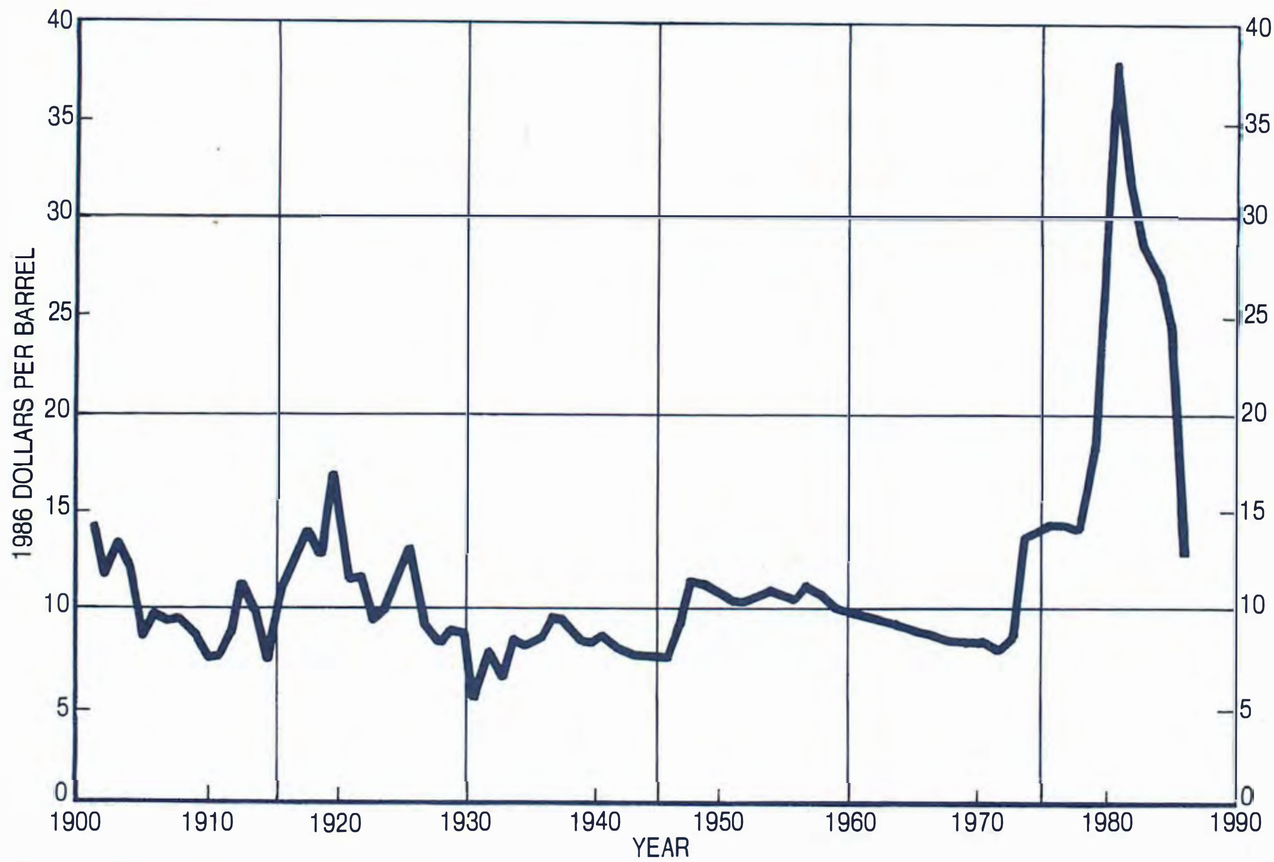


Figure 15. Annual Average U.S. Crude Oil Wellhead Prices (Constant 1986 Dollars per Barrel)

short of the level required to meet demand growth.

As shown in Figure 16, wellhead natural gas price instability has also increased significantly since 1970.

Prior to the rapid fall in oil prices, the general outlook for oil in the non-communist world was one of price-constrained demand growth and a fairly constant level of non-OPEC production through the 1990s.[3] In the Energy Information Administration's (EIA) Annual Energy Outlook 1985, a "low imports case" projection was developed that reflected the U.S. oil supply/demand balance at flat-to-growing real crude oil prices. As shown in Table 3, net imports were projected to increase from 27 percent of consumption in 1985 to 31 percent in 1990 and 39 percent in 1995.

TABLE 3

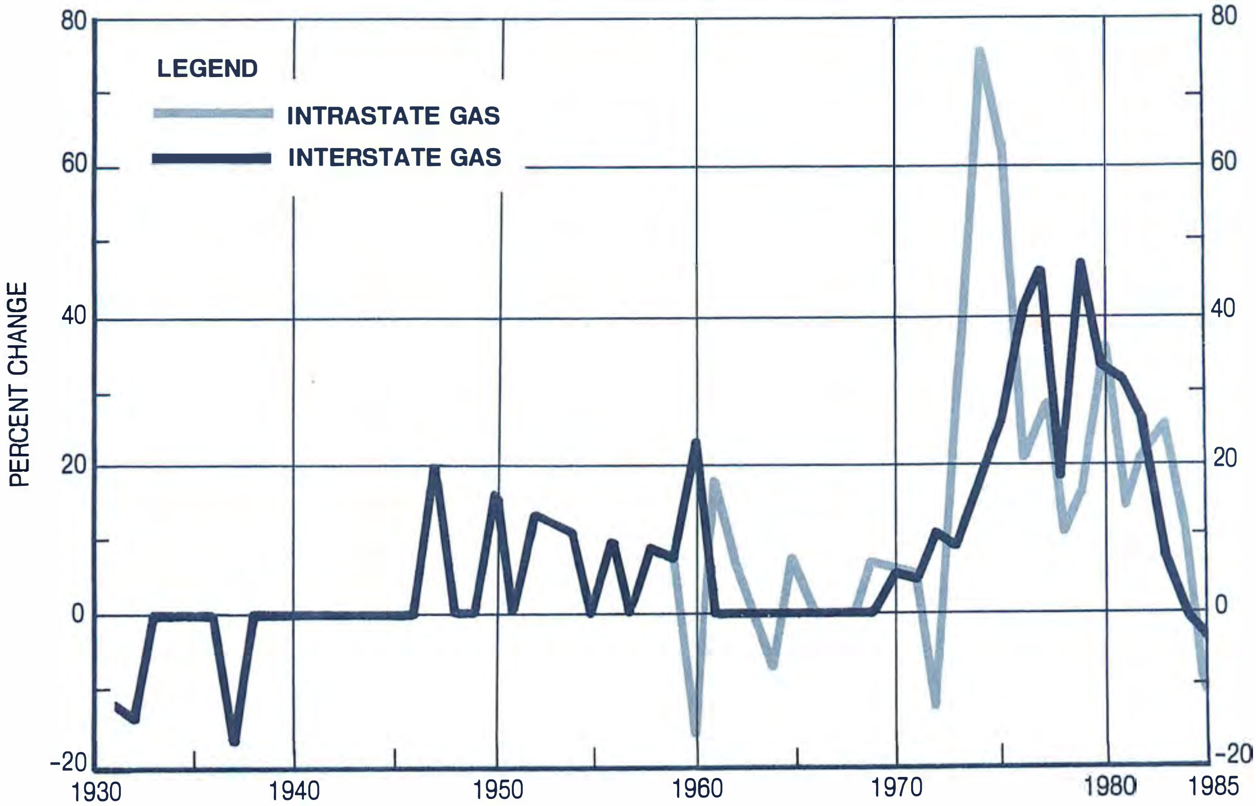
ENERGY INFORMATION ADMINISTRATION
U.S. OIL SUPPLY/DEMAND BALANCE
ANNUAL ENERGY OUTLOOK 1985
LOW IMPORTS CASE
(Million Barrels Per Day)

	Actual 1985	1990	1995
Refiner Acquisition Cost of Crude Oil (1985 $/bbl)	$27	$32	$37
Domestic Consumption	15.7	15.4	15.7
Domestic Crude Oil Production	9.0	8.4	7.4
Natural Gas Liquids and Other Supply	2.5	2.3	2.2
Total Domestic Supply	11.5	10.7	9.6
Net Imports Needed to Meet Demand	4.2	4.7	6.1
Imports as a Percent of Consumption	27%	31%	39%

NPC Oil & Gas Outlook Survey

Since the EIA forecast, the rapid decline in oil prices in 1986 has dramatically affected the perception of current and future supply and demand balances. Oil supply will fall more quickly and oil demand will increase more rapidly. In

[3]Source: U.S. Department of Energy's National Energy Policy Plan Projection to 2010, December 1985.



SOURCE: Prices are taken directly from or calculated from data in the *Natural Gas Monthly* published by the Energy Information Administration of the Department of Energy.

Figure 16. Percent Change in Annual Average Natural Gas Wellhead Prices (Nominal Dollars per Thousand Cubic Feet).

order to gauge the impact of the 1986 price decline, the NPC surveyed a broad spectrum of industry, utility, government, consulting, and financial community representatives for their estimates of future supply and demand outlooks under two price trends provided by the Department of Energy: an upper price trend starting at $18 per barrel in 1986 and rising at 5 percent per year in real terms to $28 in 1995, and a lower price trend starting at $12 per barrel and rising at 4 percent per year in real terms to $17 in 1995. These two price trends, shown in Table 4, were designed to measure the differences in future U.S. oil and gas supply and demand levels resulting from differing price assumptions.

In evaluating the NPC survey, the Council recognizes that straight line growth in petroleum prices of 4 to 5 percent for 15 years, as presented in the two price trends, is an unlikely scenario. In fact, history reveals no period of time when such even growth occurred. Nevertheless, the responses to the survey are directionally consistent, i.e., low prices stimulate demand and retard supply, and the converse is true for higher prices. However, in the later years of the survey, non-communist world oil supply and demand may tighten to the point that prices could vary substantially from the price trends provided by the Department of Energy (DOE). That is, the demand on Middle East OPEC oil may either require additional capacity or the OPEC producers may choose to raise prices faster than the DOE price trends to rebalance supply and demand.

Under the NPC upper price trend, net imports rise from 4.2 million barrels per day in 1985 to 6.2 in 1990 and 7.9 in 1995, with net import dependence surging from 27 percent in 1985 to 38 percent in 1990 and 47 percent in 1995. In comparing these levels of import dependence with those forecast by the EIA, shown in Table 3, it becomes evident that the lower prices assumed in the NPC upper price trend accelerate the level of import dependence about five years.

As shown in Table 4, U.S. import dependence reaches the 47 percent level of the late 1970s in 1995 in the upper price trend, while it reaches this level five years earlier in 1990 in the lower price trend. Current net import dependence is approaching that of the 1973–74 Arab oil embargo.

TABLE 4

SURVEY RESPONSE
U.S. OIL SUPPLY/DEMAND BALANCE
(Million Barrels Per Day)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Refiner Acquisition Cost of Crude Oil (1986 $/bbl)	$27	$22	$28	$36
Domestic Consumption	15.7	16.3	17.0	17.4
Domestic Crude Oil Production	9.0	8.0	7.0	6.4
Natural Gas Liquids and Other Supply	2.5	2.1	2.1	1.9
Total Domestic Supply	11.5	10.1	9.1	8.3
Net Imports Needed to Meet Demand	4.2	6.2	7.9	9.1
Imports as a Percent of Consumption	27%	38%	47%	52%
Lower Price Trend				
Refiner Acquisition Cost of Crude Oil (1986 $/bbl)	$27	$14	$17	$21
Domestic Consumption	15.7	17.6	19.0	19.9
Domestic Crude Oil Production	9.0	7.1	5.7	4.5
Natural Gas Liquids and Other Supply	2.5	2.1	1.9	1.8
Total Domestic Supply	11.5	9.2	7.6	6.3
Net Imports Needed to Meet Demand	4.2	8.4	11.4	13.6
Imports as a Percent of Consumption	27%	48%	60%	68%

The supply outlook in these surveys responds to lower oil prices in two key ways. First, lower prices diminish the attractiveness of development opportunities and result in a substantial reduction in industry spending. Second, exploration for new oil-producing capacity, particularly in higher cost areas, is being deferred. The difference in domestic supply reflected in the lower and upper price trends measures the industry's perception of these two factors by the $6 to $15 variation in the two price trends. It also reflects the reduction in cash flow available for investment as a result of the different prices.

Likewise, the growth in demand reflects reduced or delayed conservation efforts; delays in the construction of facilities that will substitute other fuels for oil; and the substitution on economic grounds, when prices are low enough, of oil for natural gas and certain other fuels.

The combination of higher demand and reduced supply in either price scenario results in a tightening of the oil supply/demand balance and increases the demand for Middle East OPEC oil.

Under the upper price trend, the NPC survey also indicates that 30 percent of non-communist world demand will have to be supplied by Middle East OPEC in 1995 and 35 percent in 2000, up from 21 percent in 1985 (see Table 5). Under the lower price trend, this dependence rises to approximately 40 percent in 1995 and over 45 percent in 2000. Middle East OPEC possesses 63 percent of non-communist world proved crude oil reserves, and these countries could meet the higher export levels if they chose to do so. However, as OPEC production increases and its surplus capacity declines, its members will have greater power to increase prices. During the 1970s, as the level of OPEC production capacity utilization increased above 80 percent, OPEC was able to increase prices and maintain them at high levels. The surveys indicate that OPEC will once again be producing at 80 percent of its current capacity rate before 1990 in the lower price trend and before 1995 in the upper price trend.

The flexibility to switch to alternative fuels, such as natural gas or coal, is important in the event of an oil supply disruption. Such flexibility already exists to a large degree in industrial boilers and power plant boilers and networks. The natural gas shortages in the 1970s stimulated many of these users to install fuel oil burners and storage tanks. Currently, fierce price competition exists for this switchable market, which accounts for 2 to 3 trillion cubic feet of total industrial and power plant usage.

As shown in Table 6, at the survey price trends, falling domestic production plus available gas imports will be insufficient by the 1990s to maintain gas consumption at historical levels (with wellhead gas prices determined through a netback from the burnertip in competition with low sulfur residual fuel oil prices). Net dry gas production declines from 16.4 trillion cubic feet in 1985 to 15.2 trillion cubic feet in 1995, and 14.5 trillion cubic feet in 2000 in the upper price trend, and to 13.3 trillion cubic feet in 1995 and 12.4 trillion cubic feet in 2000 in the lower price trend.

Although gas is much less transportable from foreign sources than oil, increasing amounts of other gas supplies will be required through the year 2000. Requirements are approximately the same in both trends, rising

TABLE 5

SURVEY RESPONSE
NON-COMMUNIST WORLD OIL SUPPLY/DEMAND BALANCE
(Million Barrels Per Day)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Total Consumption	46.4	48.2	50.5	52.5
Non-OPEC Crude Oil and Natural Gas Liquids	25.2	24.7	23.9	22.5
Other Supply	4.0	2.9	2.6	2.5
OPEC Crude Oil & Natural Gas Liquids Production*	17.2	20.6	24.0	27.5
Total Supply	46.4	48.2	50.5	52.5
Memo: Middle East OPEC Crude Oil as a Percentage of Total Supply	21%	25%	30%	35%
Lower Price Trend				
Total Consumption	46.4	51.0	54.7	58.0
Non-OPEC Crude Oil and Natural Gas Liquids	25.2	22.4	20.4	18.6
Other Supply	4.0	2.8	2.5	2.4
OPEC Crude Oil & Natural Gas Liquids Production*	17.2	25.8	31.8	37.0
Total Supply	46.4	51.0	54.7	58.0
Memo: Middle East OPEC Crude Oil as a Percentage of Total Supply	21%	32%	40%	46%

*The OPEC production levels represent the volumes required to balance total non-communist world consumption versus non-OPEC production plus net communist imports. Current OPEC production capacity is estimated to be 27 million barrels per day of crude oil and condensate, and an additional 1.5 to 2.0 million barrels per day of natural gas liquids.

TABLE 6

SURVEY RESPONSE
U.S. NATURAL GAS SUPPLY/DEMAND BALANCE
(Trillion Cubic Feet Per Year)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Domestic Consumption	17.3	17.6	17.3	17.0
Domestic Production (Dry Gas)	16.4	16.4	15.2	14.5
Net Imports	0.9	1.3	2.2	2.6
Other Supply and Inventory Change	0.0	(0.1)	(0.1)	(0.1)
Total Supply	17.3	17.6	17.3	17.0
Memo: Unsatisfied Gas Demand*				
Filled By Oil—TCF	—	—	<0.1	0.2
—MMB/D oil equivalent	—	—	<0.1	0.1
Lower Price Trend				
Domestic Consumption	17.3	17.0	15.5	15.0
Domestic Production (Dry Gas)	16.4	15.5	13.3	12.4
Net Imports	0.9	1.5	2.2	2.6
Other Supply and Inventory Change	0.0	0.0	0.0	0.0
Total Supply	17.3	17.0	15.5	15.0
Memo: Unsatisfied Gas Demand*				
Filled By Oil—TCF	—	0.3	0.7	1.0
—MMB/D oil equivalent	—	0.1	0.3	0.5

*Reflects the amount by which natural gas supply (domestic production plus imports) fell short of natural gas demand after balancing the results of survey responses. At the price levels in the survey, imports are constrained by economics and transmission capacity. The resulting shortfall in gas supplies constrained natural gas consumption, and the unsatisfied demand was assumed to be filled by oil since oil and gas can be substituted in a large number of dual-fired boiler applications. Since some individual respondents could have converted unsatisfied gas demand to other forms of energy in their submittals, these unsatisfied gas demands could be understated.

from 0.9 trillion cubic feet in 1985 to about 2.6 trillion cubic feet in 2000. At the price levels used in the survey, imports are constrained by the availability of gas supplies and existing transmission capacity into the United States. Canada accounts for about 85 percent of these supplies. Limited amounts of liquefied natural gas are not expected until after the mid-1990s. Additional gas imports could be available if gas prices were higher than assumed in the survey.

According to the survey, the gas bubble ends by the late 1980s in the lower price trend and during the first half of the 1990s in the upper price trend. Once the gas bubble ends, burnertip gas prices will need to rise above low sulfur residual fuel oil prices to reduce potential gas demand, mostly through fuel switching to oil in the dual-fired boiler market. This switching would occur first in those regions farthest from the gas-producing areas, because their gas delivery costs are the highest. This shortfall will be filled through increased oil imports, which in the lower price trend could range as high as 500,000 barrels per day by 2000.

Alternative Fuels

Fuels other than oil and natural gas represent major potential future sources of energy for the United States. Coal and nuclear offer the greatest potential for the United States during the balance of this century. The EIA Annual Energy Review 1985 illustrates the magnitude of these resources, as shown in Table 7, both in terms of absolute volume and years of supply.

Institutional, technical, and regulatory problems are effectively limiting the contribution of coal and nuclear power to our energy sources. Among these are environmental restrictions on burning coal, restrictions on coal transportation alternatives, and lengthy licensing and permitting procedures for nuclear plants.

Given the NPC oil price trends, nuclear usage could be lower if new nuclear plants that are near completion are not finished or if existing plants are shut down prior to the end of their useful lives. Coal usage could be lower if new construction is delayed or because of environmental constraints. If these situations occur, oil will most likely be the fuel substituted, creating a larger demand for imports.

TABLE 7

COAL AND URANIUM RESERVE BASES*

	Billions of Short Tons	Billion Barrels of Oil Equivalent	Years of Supply‡
Coal, Recoverable Reserve Base (Beginning of 1985)	283	1,075	319
	Millions of Pounds†	**Billion Barrels of Oil Equivalent**	**Years of Supply‡**
Uranium Reserve Base (Beginning of 1985)			
Reasonable Assured	359	12	80
Estimated Additional	1,318	45	
Speculative	1,040	36–1,800§	50–2,500§

*DOE/EIA Annual Energy Review and International Energy Annual, 1985.

†Economically recoverable reserves at $30 per pound.

‡At the 1985 rate of consumption.

§Higher end of range assumes breeder technology.

Section I

Historical Perspective on Energy Crises and U.S. Policy Responses

Chapter One

Introduction

In the 1970s, the world experienced two energy crises due to the 1973 Arab oil embargo and the 1979 Iranian revolution. However, since 1950, several other potential crisis situations occurred that did not lead to dramatic price increases similar to those of the 1970s and early 1980s. These included the Iranian nationalization of the early 1950s, the Suez Canal closure in 1956, and the 1967 Arab/Israeli war. The primary reason why these situations did not result in major price increases was that, prior to 1970, significant excess oil productive capacity existed outside of OPEC, especially in the United States. The downturn in U.S. production after 1970, coupled with rising non-communist world oil demand, significantly increased the dependence of the non-communist world—especially the United States—on imports from Middle East OPEC (see Figure 17). This increased the vulnerability of the non-communist world to oil supply disruptions and/or rapid oil price increases.

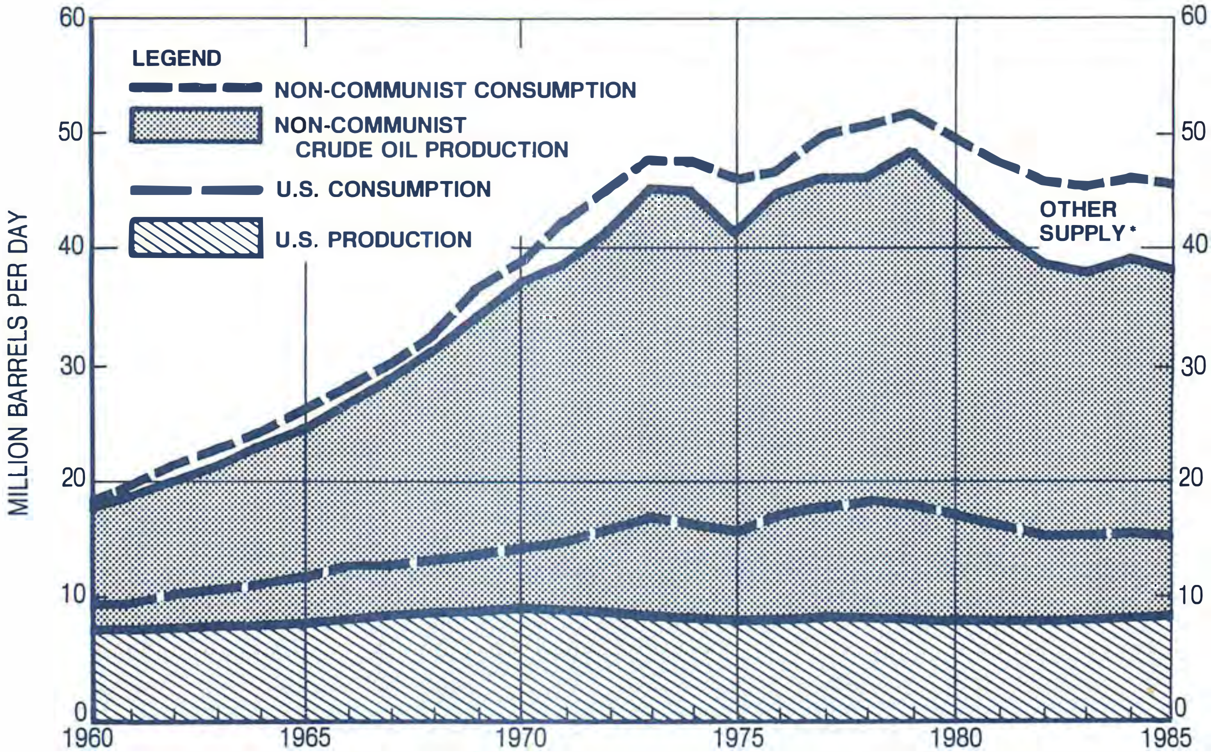
In addition, during the 1960s and early 1970s, OPEC was developing as a force that could exploit its position to either raise oil prices, as in the 1973 crisis, to support higher price levels, such as post-1973, and to sustain the spot oil price increases, such as those induced by the Iranian crisis. However, in the early 1980s, excess productive capacity challenged OPEC's resolve to maintain prices at 1981 levels.

Since 1981, oil prices have declined, with a collapse occurring in early 1986. The U.S. refiner acquisition cost of crude oil declined from a peak of over $37 per barrel in March 1981, to about $27 per barrel in December 1985, and to $12 per barrel in mid-1986. The price of West Texas Intermediate crude oil declined from $32 per barrel in November 1985 to as low as $10 per barrel in 1986. These price declines occurred because oil demand fell and non-OPEC supplies grew—both of these actions in response to higher prices—increasing the excess productive capacity of OPEC members.

When OPEC's production has been over 80 percent of its available capacity, as in 1973 and the late 1970s, OPEC has been able to push prices upward or maintain them at high levels. In the 1980s, OPEC's capacity utilization rate fell below 60 percent, and OPEC failed to maintain prices. In late 1985 and early 1986, certain of OPEC's members decided to regain market share, causing the price of oil to collapse.

The sharp price decrease of early 1986 has caused the oil industry to drastically reduce its exploration and development expenditures; production has declined; the work force has been cut substantially; and the industry is restructuring. The exploration and production support and service industry has been especially hard hit. Given the size of the petroleum industry in the overall U.S. economy, the reductions in the oil industry are having negative effects on the economy that initially offset the positive effects of the lower prices. The energy crises of the 1970s and the latest price decrease are making long-term energy planning difficult for producers, consumers, and governments.

Oil prices have been more volatile since 1973 than in the three previous decades. But, as shown in Figure 18, the recent yearly percentage changes in wellhead oil prices are rivaled by those that occurred in the 1900 to early 1930s



*Natural gas liquids, net imports from communist countries, refinery gain, inventory change, tar sands, shale, and synthetic fuels.

Figure 17. U.S. and Non-Communist World Oil Consumption vs. Production.

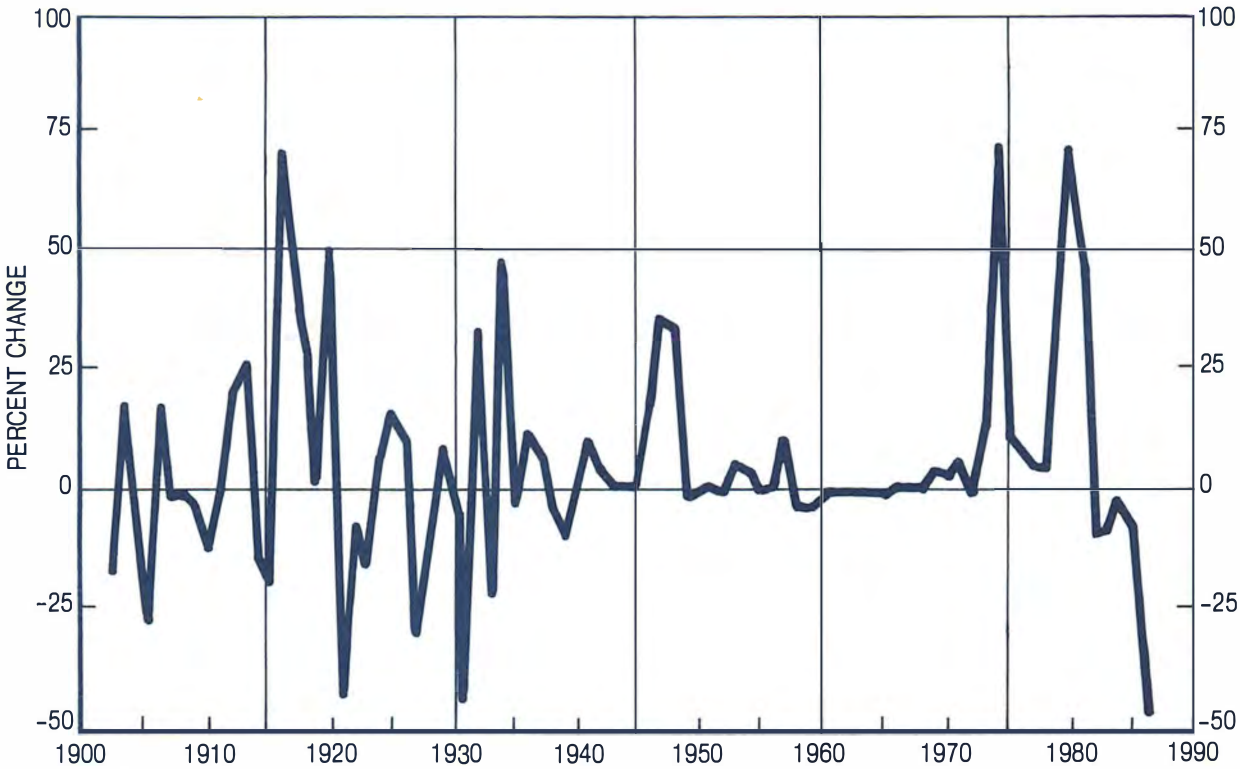
period. (Figure 31 in Chapter Five contains the actual wellhead oil price levels.) Furthermore, as shown in Figure 19, although gas prices were more stable than oil prices from 1930 to 1970, they too have displayed increased instability since 1970. Interstate wellhead gas prices were controlled by federal regulators, and price increases from 1970 to the early 1980s were allowed in order to increase gas supplies. Since then, gas prices have decreased in response to the excess gas deliverability that has developed.

Energy crises are not just restricted to oil. Supply curtailments and dislocations were already commonplace in the natural gas market when the 1973 oil embargo started. Because federal and state regulations held down the price of natural gas, demand grew rapidly from the 1940s through the early 1970s. However, interstate supply stagnated since reserve additions were often dedicated to the intrastate market due to higher unregulated prices, especially in the 1960s and the 1970s. Interstate gas supply shortages were developing by the late 1960s. In response to the shortages, the regulators did allow interstate gas prices to rise but not to the levels corresponding to the oil price increases after 1973. This maintained and increased the potential demand for gas and induced fuel switching from oil where possible, but offered little incentive to bring forth additional supply, exacerbating the gas supply shortage.

One means to offset an oil supply shortage and/or lessen the impact of higher oil prices would have been the flexibility to switch from oil to an alternative fuel, such as gas. Since inadequate gas supply existed in the United States in the 1970s, many companies were forced to maintain or install the capability to also burn oil. This aggravated the effect of the oil price shock on the U.S. economy and increased U.S. oil import dependence.

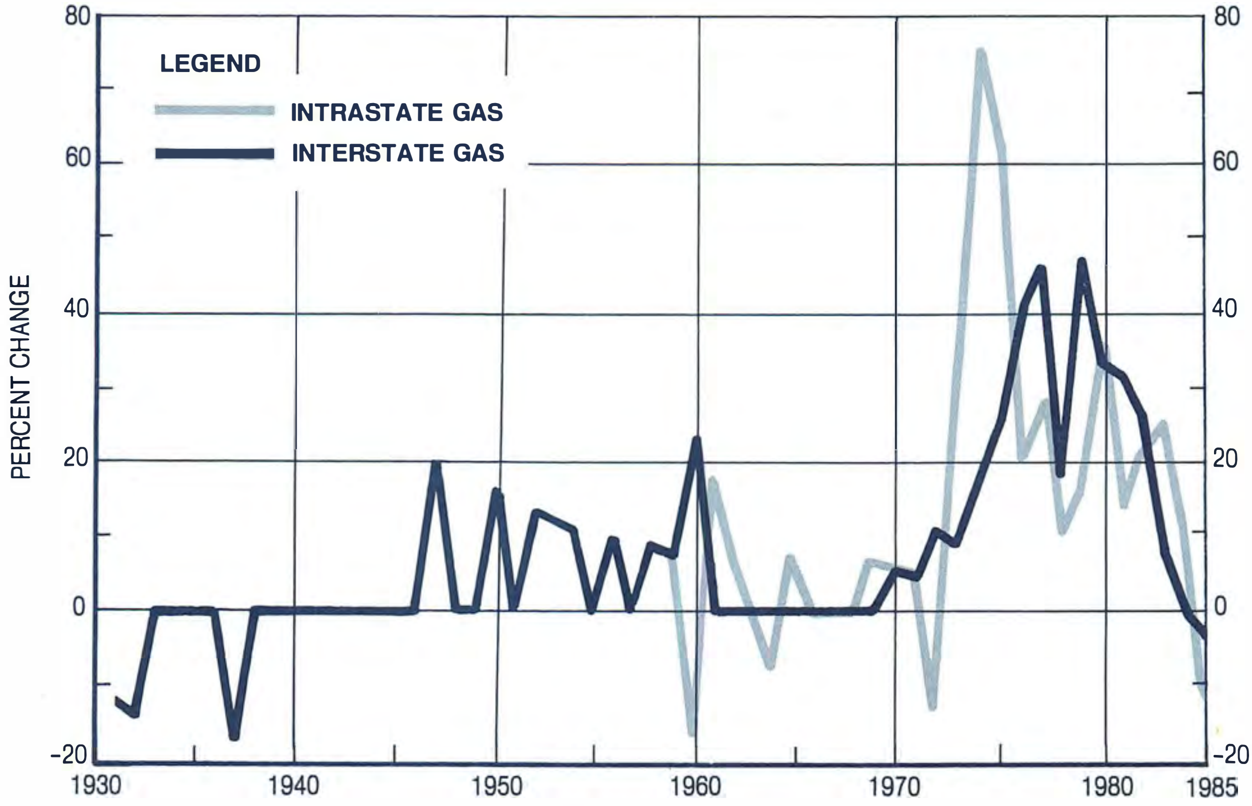
The increasing dependence of the United States on imports in the 1970s, especially from Middle East OPEC producers, seriously increased its vulnerability to oil price shocks. In addition, since the world oil market was highly integrated, the United States could not have isolated itself from an oil price shock even if it had not been dependent on Middle East sources. That is, other areas, especially Western Europe and Japan, would have then been even more dependent on the Middle East OPEC producers for their imports. A price shock originating from a cutback in Middle East supplies would have affected the United States as it rippled through to non-Middle East suppliers.

The United States should have paid attention to the warning signals that indicated a growing U.S. and world vulnerability to events in the oil market. Figures 20 through 24 summarize a set of warning signals for the United



SOURCE: *Salomon Brothers*

Figure 18. Percent Change in Annual Average Crude Oil Wellhead Prices (Nominal Dollars per Barrel).



SOURCE: Prices are taken directly from or calculated from data in the *Natural Gas Monthly* published by the Energy Information Administration of the Department of Energy.

Figure 19. Percent Change in Annual Average Natural Gas Wellhead Prices (Nominal Dollars per Thousand Cubic Feet).

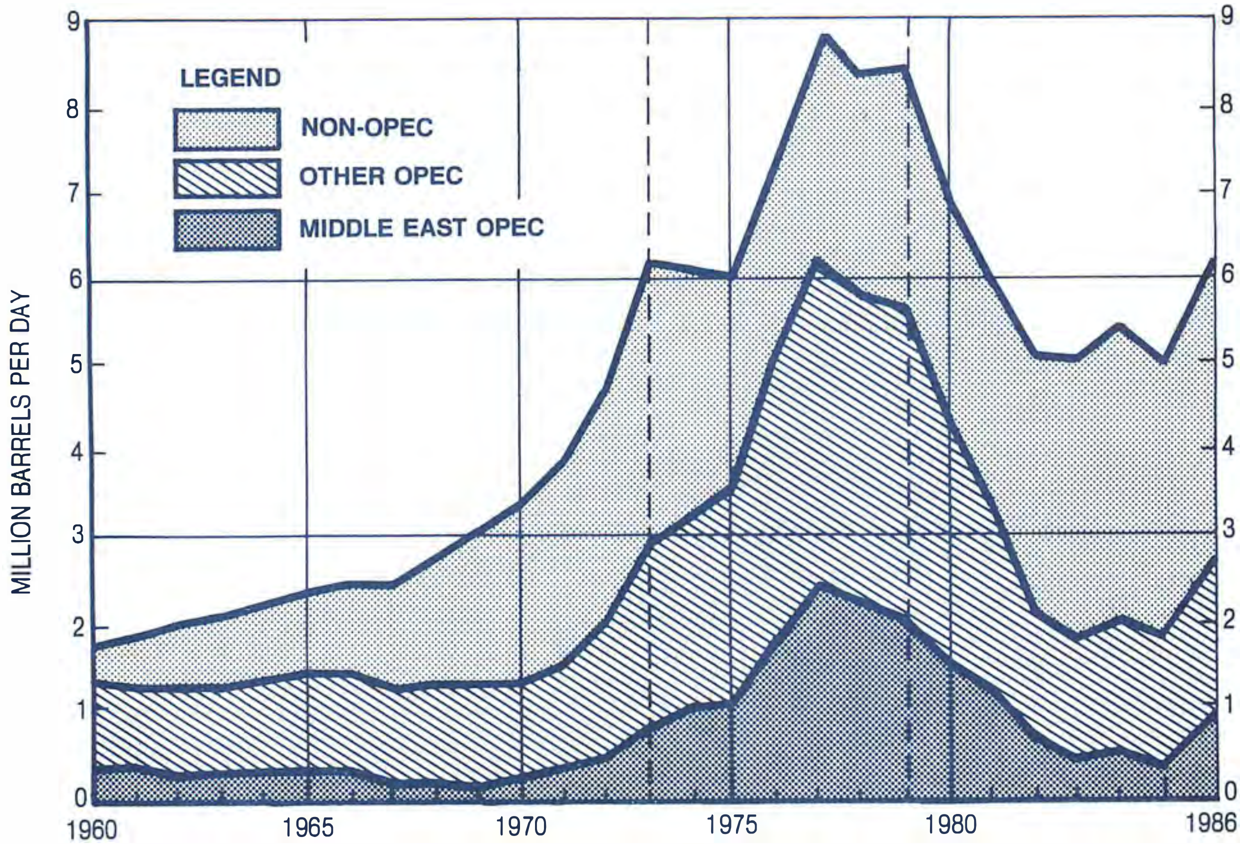


Figure 20. Gross U.S. Imports of Crude Oil and Refined Products by Source.

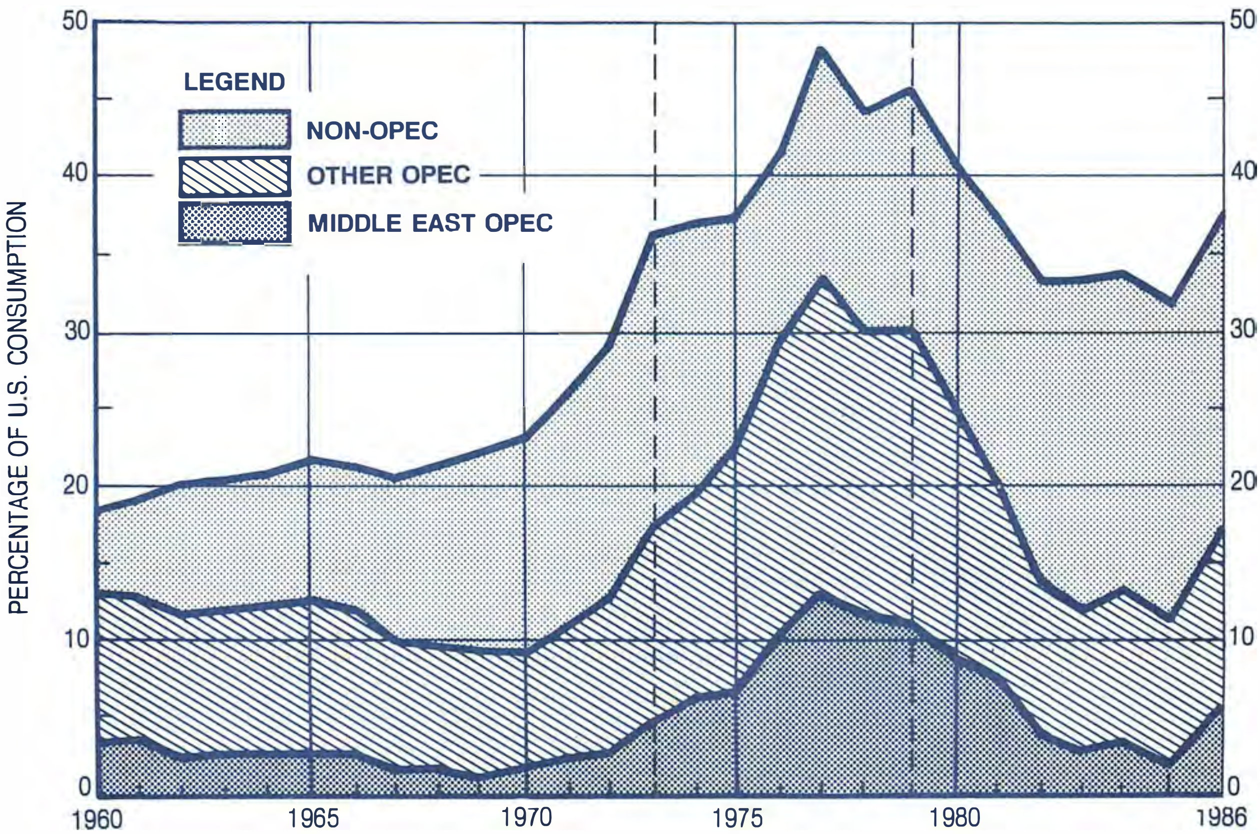


Figure 21. Gross U.S. Imports of Crude Oil and Refined Products by Source as a Percentage of Consumption.

States. Comparable charts could also be developed for other non-communist countries either individually or in total. The trends on these figures prior to the 1973 and 1979 energy crises represent the basic warning signals. These signals include:

- Low or declining levels of excess oil production capacity in the Middle East OPEC and other OPEC countries
- Increasing imports of crude oil and refined products, both in absolute terms (Figure 20) and as a percentage of total U.S. consumption (Figure 21), both in total and from insecure sources such as the Middle East OPEC and other OPEC countries
- Trends towards lower reserve-to-production ratios for crude oil and natural gas (Figure 22)
- Inability to replace domestic petroleum production with domestic petroleum reserve additions (Figure 23 for crude oil and Figure 24 for natural gas)
- Governmental policies that simultaneously encourage consumption and discourage domestic production (such as low regulated interstate wellhead gas prices or price controls on oil).

As outlined throughout this report, the recent decline in oil and gas prices will increase the vulnerability of the United States and the non-communist world to future energy price shocks. In order to determine if another crisis may be building, these signals of past vulnerability will need to be monitored closely in the future.

The remaining chapters in Section I discuss many of these historical issues in more detail.

Chapter Two reviews the historical actions and events in the oil and gas industry that led to the energy crises. This chapter describes the factors that increased U.S. vulnerability to the 1970s oil supply disruptions, along with the U.S. governmental policy responses to the crises. Since the U.S. natural gas crisis of the 1970s contributed to the severity of the oil crises, this chapter also reviews the factors and the governmental policies affecting natural gas. Finally, the government's energy policy responses to the crises are evaluated with regard to their effects on the crises.

Chapter Three discusses the effects of the energy crises on the U.S. economy, and analyzes the effect of the recent oil price decline on the economy.

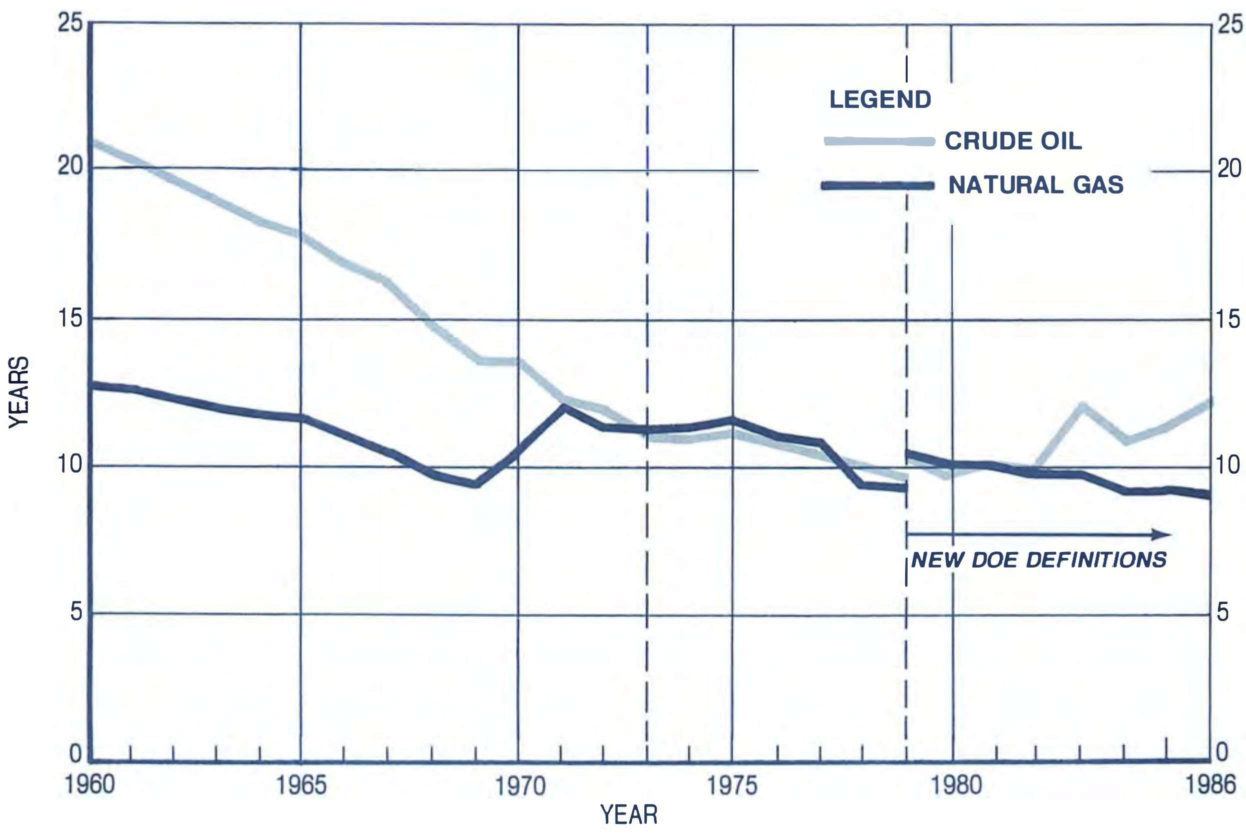


Figure 22. U.S. Reserves to Production Ratios of Oil and Natural Gas.

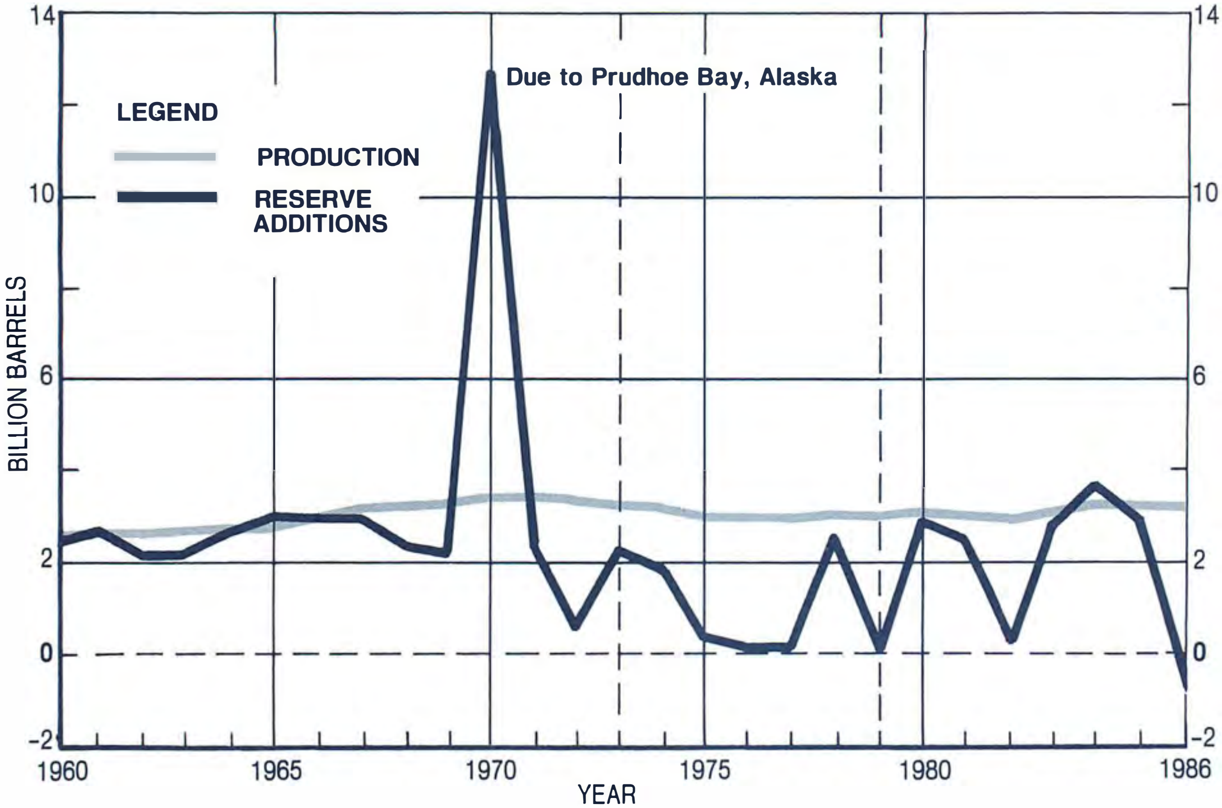


Figure 23. U.S. Crude Oil Production vs. Reserve Additions.

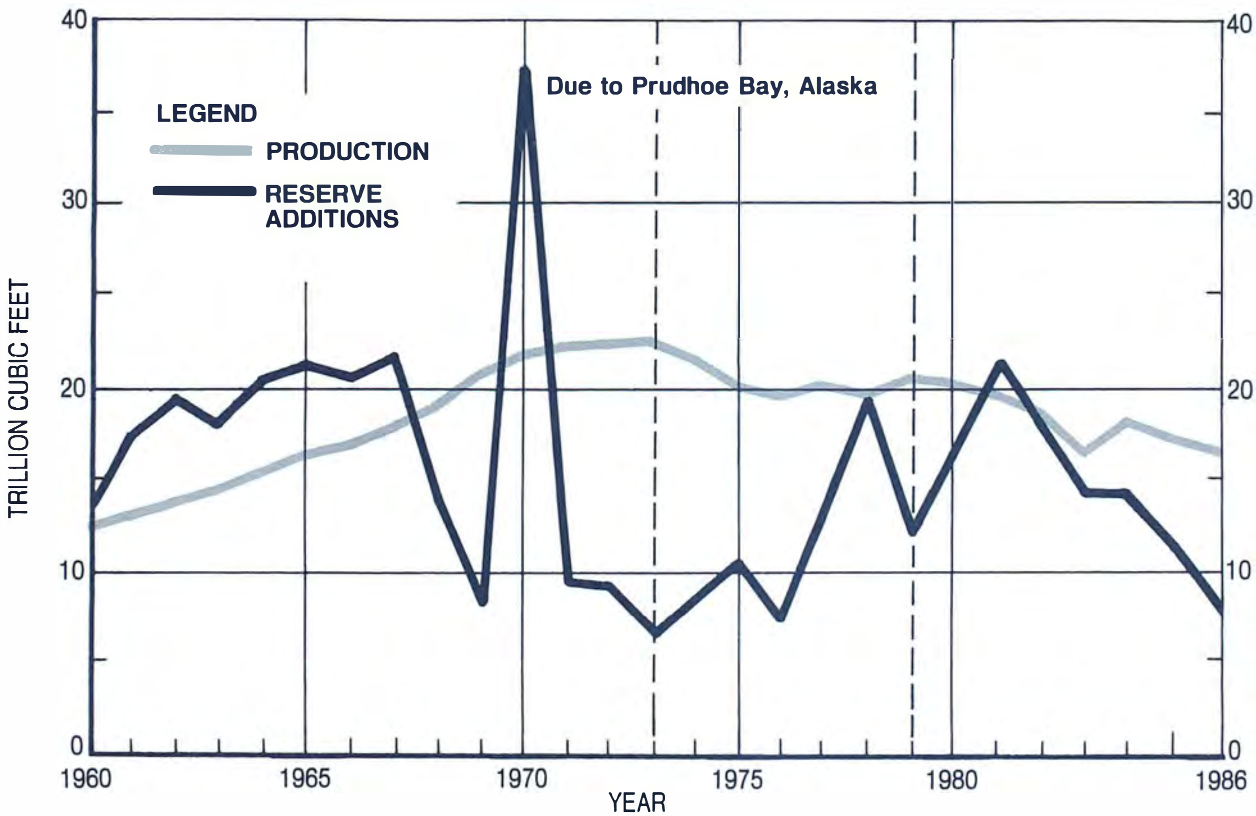


Figure 24. U.S. Natural Gas Production vs. Reserve Additions.

CHAPTER TWO

HISTORICAL ACTIONS AND EVENTS ASSOCIATED WITH THE ENERGY CRISES OF THE 1970s

INTRODUCTION

The purpose of this chapter is to identify those actions and events that contributed to the energy crises experienced by the United States during the decade of the 1970s. Three separate energy crisis periods have been analyzed: the Arab oil embargo of 1973–74; the natural gas curtailments of the mid-1970s; and the Iranian oil crisis of 1978–79. In each case, attempts will be made to identify and discuss the factors that precipitated or otherwise contributed to the development of the crisis, as well as the reactions of government, industry, and consumers to the crisis situation. It is hoped that by reviewing the events and decisions of the past, government and industry alike will be better prepared to avoid or mitigate the vulnerability to future supply disruptions.

SUMMARY AND OVERVIEW OF PRE-EMBARGO HISTORY (Up to 1973)

Pre-War Energy Policies

Prior to World War II, the federal government's role in energy was primarily directed at control of the public domain (pursuant to provisions of the Mineral Leasing Act of 1920), taxation, and the regulation of interstate commerce. However, there were other instances of government involvement—for example, the adoption in 1932 of a 21¢ per barrel tariff on imported crude oil and the passage of the Connally Hot Oil Act. The tariff was imposed at the request of the domestic industry in an effort to combat the combined effects of low demand brought about by the Depression and production from the new prolific East Texas discoveries. The tariff achieved the desired results, reducing imports almost immediately. The Texas Railroad Commission began effective implementation of prorationing in 1933, protected by a Presidential Executive Order under the National Industrial Recovery Act, which prohibited the shipment, interstate or abroad, of oil produced contrary to state laws. After the National Industrial Recovery Act was ruled unconstitutional in 1935, the Connally Act was passed, extending federal enforcement of state proration laws.

The Wartime Effort

In May of 1941, President Franklin Roosevelt created the Office of the Petroleum Coordinator of the National Defense. The war period was characterized by cooperation between government and business leaders.

The government's coordinator role was formalized in the Petroleum Administration for War. The industry's advisory function was provided by the Petroleum Industry War Council, which was composed of 66 oil industry executives selected by the coordinator. The recommendation of the council, in light of exceptional domestic fuel demands, was that the U.S. companies embark on an effort to secure access to the world's oil supplies.

In 1945, concerned over the need to maintain domestic productive capabilities, the War Council adopted the "Petroleum Policy for the United States," which remained the industry's official public policy on the import question for the next two decades. It stated that imports should be limited to the amount "absolutely necessary" to augment domestic production and that import quantities should not depress domestic output. By the end of the war, however, increasing demand forced the United States to look to foreign supplies to meet immediate energy needs.

The Post-War Era

In 1946, President Truman abolished the Petroleum Administration and the War Council. Shortly thereafter, the Oil and Gas Division was created within the Department of the Interior to serve as the point of communication between the government and the oil industry. At President Truman's suggestion, the National Petroleum Council was also created in that year to continue the advisory role previously performed by the War Council.

The post-war availability of cheap foreign oil, resulting from the increased international exploration and production activity begun several years earlier, eventually produced distortions in existing fuels markets. The availability of cheaper imports concurrently doomed the post-war efforts to develop synthetic fuels as well as attempts to renew reliance on domestic coal (see Figure 25).

As early as 1950, well-defined consumer and national security arguments were already being developed with respect to the issue of import reliance. Access to cheaper, foreign oil was endorsed by consumer advocates and those opposing a "drain America first" strategy. However, unrestricted reliance on foreign oil supplies was also recognized as undermining national security interests.

These opposing views particularly troubled the multinational oil companies that were eager for strategic as well as market reasons to establish their presence in the Middle East, and whose concessions were dependent on increasing output and export sales, most notably to the United States, the world's largest and fastest growing market.

While the debate continued, net import volumes steadily increased, from just over 300 thousand barrels per day (MB/D) in 1948 to 550 MB/D in 1950 and to over 1 million barrels per day (MMB/D) by 1956.

Despite disagreements within the producing industry between domestic independent producers and the multinationals, there existed a shared fear that unless the import trend were controlled, government would step in with more rigid policy remedies. This produced attempts to reduce imports on a "voluntary" basis. However, the outbreak of the Korean War and the associated resurgence in oil demand encouraged both increased domestic output and imports of foreign oil.

By 1953, the combination of a leveling of demand and increasing imports caused state pro-

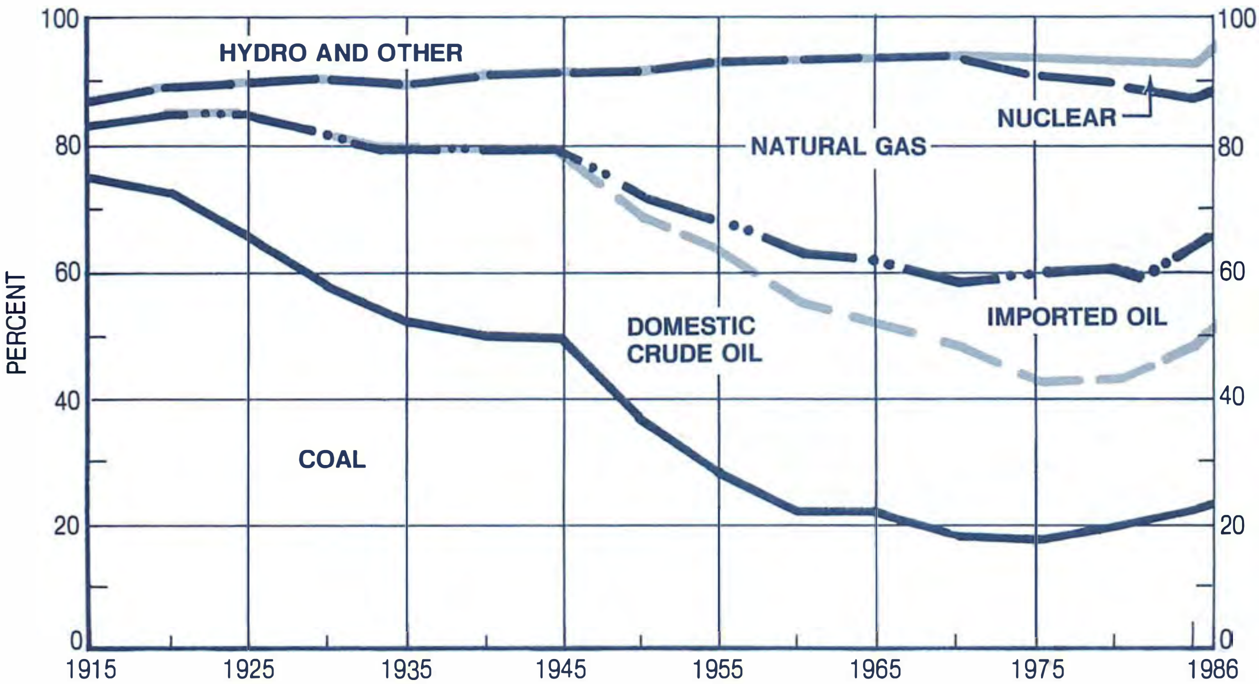


Figure 25. U.S. Consumption of Energy Fuels—1915–1986 (Percent on a BTU-equivalent Basis).

rationing authorities in Texas, Louisiana, and Oklahoma to restrict and stabilize output from domestic wells. In addition to crude oil, imports of residual fuel oil were also on the rise. Calls for "protectionism" were renewed by producing-state politicians and their constituents, but rejected by the newly elected Eisenhower administration.

By the mid-1950s, net oil imports had approached 1 MMB/D and accounted for over 11 percent of domestic demand. Some 2 MMB/D of domestic production was shut in.

In August 1956, a coalition of domestic producers and industry trade associations petitioned the Office of Defense Mobilization to review the imports issue pursuant to the national security provisions of the trade act of 1955.

In the fall of 1956, the Suez Canal was closed as a result of renewed fighting between Israel and Egypt. The conflict substantially reduced oil supplies to Europe for several months, but more importantly served to underscore the consequences of import reliance.

President Eisenhower created a special committee composed of several of his cabinet officers to investigate the imports question and to recommend a remedy. The committee's recommendation was that crude oil imports should be "voluntarily" restricted so as not to exceed 12 percent of domestic production.[1] Under the program, historical importers were allowed a pro-rata share based on their previous import volumes. New importers were also given the opportunity to gain access to cheaper foreign oil, but on a more limited basis.

After some limited initial success, the Voluntary Oil Import Program, since it had no teeth for enforcement, began to be abused. Several importers exceeded their allotments, and by mid-1958 the combination of increased imports and a recessionary economy forced additional U.S. wells to be shut in.

On March 10, 1959, under pressure to preserve domestic production, President Eisenhower signed an executive order establishing a mandatory governmental program for oil imports, a program that was to last, in various forms, for the next 14 years as a volume control program and 7 additional years as a fee program. Ironically, companies that had earlier complied with the government's request to voluntarily reduce import volumes were now penalized for their efforts. When mandatory quotas were established in 1959, the period of voluntary reductions was used as the base period for computing further import reductions.

[1] "Recommendations of the Special Committee to Investigate Crude Oil Imports." July 29, 1957.

The Mandatory Oil Import Program (1959–73)

The stated objective of the Mandatory Oil Import Program was to ensure the preservation of a healthy domestic petroleum industry and to promote national security. Under provisions of the program, crude oil import ceiling volumes were first pegged to a percentage of demand and later limited to 12 percent of domestic production. Refined petroleum product imports were also tied to historical (1957) volume levels. As a consequence, historical importers had their import purchase volumes scaled back; and new traders and importers were granted access to the program on a limited basis.

In the interests of "equity," the oil purchased using the quota tickets could be traded among interested parties. A sub-cabinet level appeals board was established to grant relief, exceptions, and allocation adjustments. Problems immediately developed, however, particularly in relation to: (1) the decision to tie quota levels to historical volumes, (2) the treatment of No. 6 oil, (3) the exchanges of quota ticket oil, especially by inland refiners, and (4) the sliding scale adjustments that allotted a disproportionately large volume of tickets to smaller refiners, whose facilities were less capable of making the higher quality refined products that consumers required.

By the mid-1960s, the allocation and equity questions were supplanted by liberalized exceptions as the principal source of problems for the quota program. Moreover, a resurgence of demand and the political efforts of the northeastern states to expand access to cheaper foreign oil resulted in increased reliance on oil imports, particularly from the Middle East.

U.S. VULNERABILITY TO OIL SUPPLY DISRUPTIONS PRIOR TO THE ARAB EMBARGO OF 1973–74

The Organization of Petroleum Exporting Countries was founded in 1960 by five oil producing nations (Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela) in response to member countries' general dissatisfaction over price and production policies established by the multinational oil companies extracting their national resources. OPEC lacked power in the early years, however, due to the presence of spare productive capacity in the United States and the member countries' reliance on the oil companies' expertise to produce their oil.

By the end of the decade, the combination of the growing demand for world oil and the resource potential of the Middle East shifted the market advantage to the OPEC producers. By 1970, the United States had become a major importer of both crude oil and refined petroleum products. The loss of domestic "surge" capacity and the growing inability of the United States to supply its allies in the event of a more localized disruption further shifted the advantage to the Middle East producers.

U.S. crude oil production peaked in 1970 at 9.6 MMB/D and began to decline, falling to 8.8 MMB/D in 1974. Net import reliance continued to grow, almost doubling from 3.2 MMB/D in 1970 to over 6 MMB/D in 1973, or 35 percent of total consumption. In particular, dependence on Middle East OPEC oil increased from less than 200 MB/D in 1970 to over 800 MB/D in 1973 (see Figures 26 and 27).

During the 1960s and early 1970s, increased demand for oil, beyond the capability of incremental new domestic supplies, was the result of a combination of factors. These factors included:

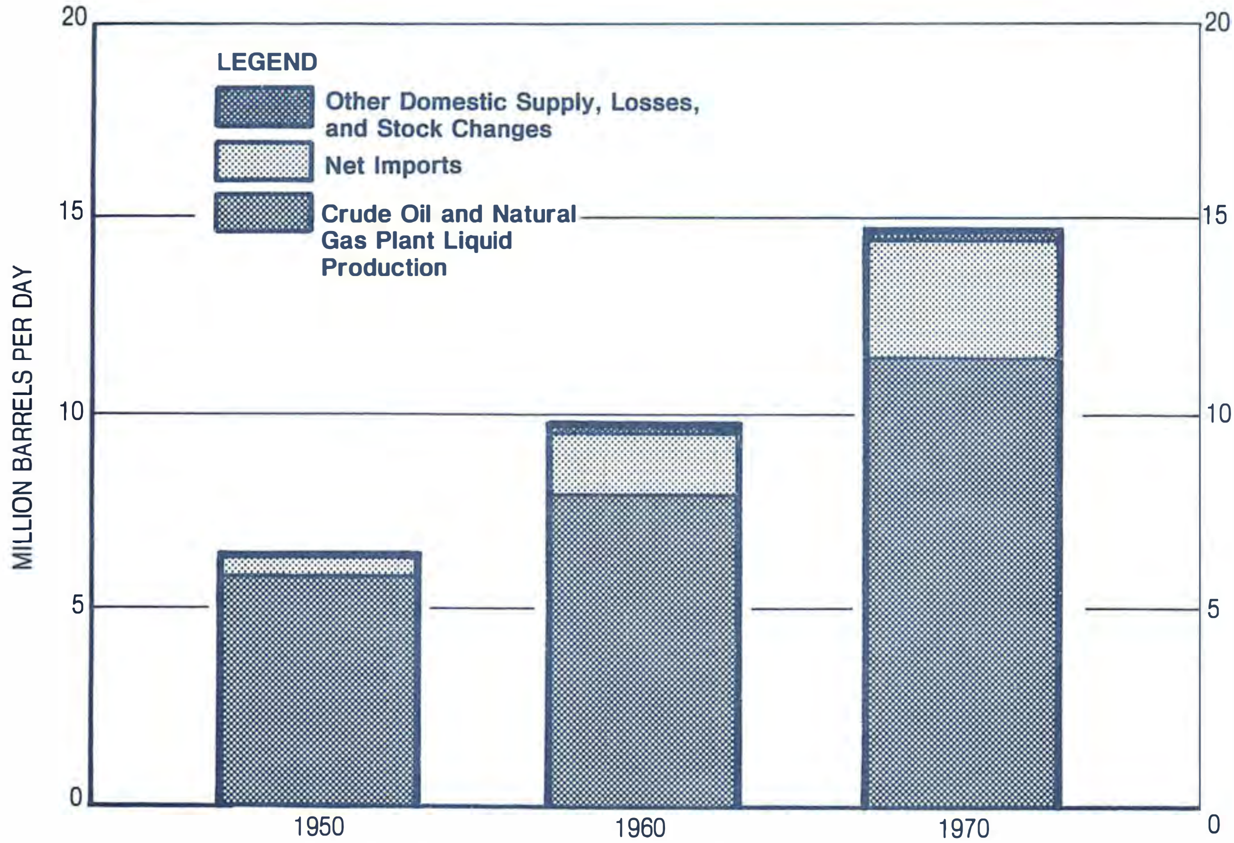
- Increased economic growth worldwide. In the late 1960s and early 1970s, economic "boom" conditions occurred simultaneously in the United States, Europe, and Japan. Growth rates in real GNP were at peak levels for the two years immediately preceding the embargo. Oil's share of worldwide energy consumption increased from 35 percent in 1960 to 46 percent in 1972.
- Reduced contribution of other fuels. Coal consumption, as a percentage of total energy use, declined; natural gas production, after initially growing, leveled off, at least in part due to price controls and uncertainty resulting from regulations and court challenges.
- The delay in the development and delivery of new oil supplies from the Outer Continental Shelf and Alaska, due to environmental and regulatory constraints.
- Increased gasoline demand stimulated by the expansion of the interstate highway system and more driving. Gasoline demand rose by 2.1 percent per year between 1960 and 1965; that growth rate more than doubled between 1965 and 1970.
- The adoption of price controls on domestic oil as part of the Nixon administration's attempts to control inflation. Price controls had the dual effect of limiting exploration activity as well as encouraging increased consumption (because of lower prices). The combination of increased demand for petroleum coupled with reduced output resulted in greater reliance on oil imports. As the exceptions to the Mandatory Oil Import Program were increased, the program became meaningless; it was formally abandoned in April 1973 and replaced with a system of license fees.

Now faced with rising oil import dependence, the United States was also constrained in locating secure sources of foreign oil supplies. In 1969, Nigeria was in the midst of a civil war; Algeria had nationalized its country's petroleum operations; a revolution in Libya had replaced a previously pro-Western government with Col. Qaddafi; the Trans-Arabian pipeline in Syria was damaged; and Canadian oil policy shifted towards restricting exports to the United States to only those volumes "surplus" to domestic needs. As a result, U.S. reliance on OPEC oil increased from 1.3 MMB/D in 1970 to just under 3 MMB/D by 1973, with about a third of that volume coming from the Middle East.

At about the same time, after negotiation of the Tehran and Tripoli agreements of 1971, OPEC prices were increased and concessions to the multinationals were eliminated. The British had withdrawn as a military presence in the Persian Gulf. The price of Saudi Arabian light crude oil increased from $1.80 per barrel in 1970 to $2.48 per barrel by 1972.

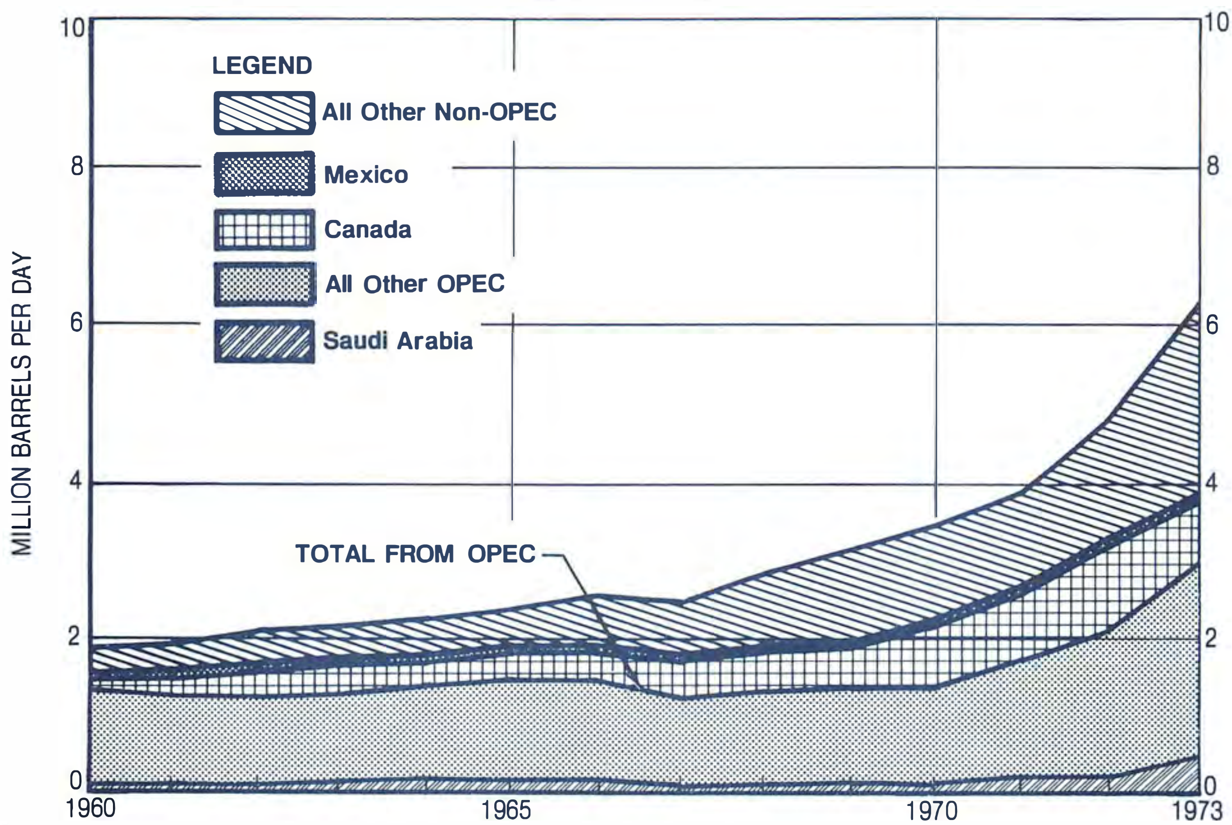
The Adoption of Oil Price Regulations Under the Economic Stabilization Act

In an attempt to curb the inflationary problems of 1970–71, the Nixon administration on August 15, 1971, imposed a wage and price freeze program that affected the entire nation. Phase I of the price control program was intended to remain in effect for only 90 days, until November 13, 1971. Phase I affected all companies, with prices frozen at August 1971 levels. The Cost of Living Council was given broad powers to administer the freeze program. Under the program, however, increased costs for imported products could, at least partially, be passed along to consumers. Consequently, under the program, domestic refiners were disadvantaged relative to their foreign competitors.



SOURCE: *Annual Energy Review 1985*, Energy Information Administration.

Figure 26. Petroleum Supply and Disposition, 1950, 1960, 1970.



SOURCE: *Annual Energy Review 1985*, Energy Information Administration.

Figure 27. U.S. Imports of Crude Oil and Petroleum Products by Country of Origin, 1960–1973.

The August freeze date imposed by Phase I controls caused particular price and supply problems for No. 2 fuel oil. Summer inventory fill discounts and high stocks depressed an already low seasonal heating oil price. The drawdown of high distillate stocks helped to avert shortages during the winter of 1971, but low prices gave no incentive to increase No. 2 fuel oil production or replenish inventories. The cold, wet fall of 1972, along with low prices, triggered increased demand for No. 2 oil and propane for heating and crop drying. Spot shortages appeared in the fall and winter of 1972–73.

Phase II of the price control program was implemented on November 15, 1971, and lasted until January 10, 1973. Under Phase II, prices were allowed to increase to cover "permissible" cost increases, but profit margins were strictly controlled.

Large firms, however, were guided by Term Limit Pricing arrangements, which allowed prices on specific products to increase so long as the weighted average increase of their total product slate did not exceed historical profit margin levels. Oil companies were not allowed to include gasoline, No. 2 oil, or residual fuel oil in Term Limit Pricing arrangements—yet collectively, these products accounted for over 70 percent of refinery yields.[2]

As a consequence of rising demand and price controls on domestic oil, import dependence continued to grow, as far as the Mandatory Oil Import Program would allow, and spot shortages of products began to develop.

On September 18, 1972, by presidential proclamation, additional imports were allowed into the East Coast as an advance to 1973 allocations. On January 17, 1973, import quotas for the East Coast were increased further. Quotas for the rest of the country were also increased.

On April 18, 1973, President Nixon issued a proclamation that suspended tariffs and quotas on imports of crude oil and refined products and shifted to a system of import license fees. On May 1, 1973, all volumetric controls on imports of oil were removed.

Phase III of the price control program began on January 11, 1973, and continued until June of that year. The goal of Phase III controls was to reduce the 1973 inflation rate to 2.5 percent by year end. The program was largely administered by the companies, and within a few months prices began to rise sharply. Congressional hearings were conducted early that spring to examine the reasons for the oil price increases. The results of the inquiry demonstrated that the price increases were largely cost justified. As indicated earlier, OPEC oil prices were on the rise during this period.

Notwithstanding the evidence justifying the rise in oil prices, congressional pressure to control inflation and restrain heating oil prices, in particular, resulted in the Cost of Living Council's issuance, on March 6, 1973, of Special Rule No. 1.

Special Rule No. 1 placed mandatory price controls on the sale of crude oil and refined products by firms with annual sales greater than $250 million—the 24 largest oil companies. The rationale was that by limiting the price increases of the larger companies, price fluctuations could be controlled on an industry-wide basis. This was not the case.

In fact, the regulations acted to disadvantage those larger, controlled companies, restricting their ability to compete for crude supplies on the world market and subsequently their ability to supply many smaller refiners and purchasers. As a consequence, historical supply patterns were disrupted, and shortages ensued. Faced with rising import prices and the loss of historical suppliers, these refiners and purchasers began to demand allocation relief.

At the same time, shortages of natural gas created increased demand for propane. Firms not regulated under Special Rule No. 1 bid up the price for propane, and some rural customers who were deprived of their historical sources were now forced to pay higher prices to secure supplies.

By May of 1973, it was apparent that relaxation of the import restrictions alone would not correct the growing supply problems, which were spreading and now threatened gasoline availability as the driving season approached. Congressional hearings were held in May of 1973 with witnesses calling for allocation relief. On May 17, Sen. Henry Jackson introduced the Emergency Fuels and Energy Allocation Act of 1973.

The legislation called for establishment of a mandatory oil allocation program. The administration resisted calls for this type of federal intervention, but recognized that the problem was growing. An amendment to the Economic Stabilization Act of 1970, giving the President discretionary authority to allocate oil supplies to meet essential needs, was offered by Sen. Thomas Eagleton and passed by Congress that spring.

[2]It should be noted that No. 2 oil and gasoline prices had been included in calculating the Consumer Price Index. Consequently, by excluding these products from price adjustments, the Consumer Price Index was artificially lowered.

In testimony before the Senate Banking Committee on May 10, the administration, in an attempt to diffuse congressional action for a mandatory allocation scheme, unveiled its proposal for the Voluntary Petroleum Allocation Program.

The voluntary program soon ran into trouble. The Ohio Turnpike Commission, for example, sued a major oil company for breach of contract relating to supply commitments for gasoline arrangements to service stations along the turnpike. An Ohio state court ruled in the commission's favor, noting that the company's participation in the voluntary program did not supersede prior contractual agreements.[3] Further, since the program was "voluntary," not all companies elected to participate. Shortages continued to develop and constituents continued to pressure Congress for mandatory allocation relief.

On June 13, 1973, Special Rule No. 1 was amended (Phase III 1/2), effectively freezing prices for all oil, imported and domestic alike. During the June 13–August 12 period, not even the increased cost of imports could be passed through. Import levels fell slightly. The reduction may have contributed to the product shortages experienced during the late summer and fall of 1973.

Phase IV of the price regulations took effect in September of 1973 and covered all segments of the industry. It established a May 15, 1973, base date for crude oil and product prices. Subsequent increases in price had to be "cost-based." Phase IV also established a two-tier price mechanism for crude oil with three categories of domestic oil—old, new, and released.[4]

Refiner product margins were also frozen at the May 15, 1973, levels under the Phase IV program, with further price increases pegged to "identifiable" cost increases.

GOVERNMENT RESPONSES TO THE OIL EMBARGO AND SHORTAGES (1973–75)

On October 6, 1973, the Arab/Israeli conflict resumed, with Egypt and Syria at war with Israel. On October 7, 11 Arab nations announced their intention to cut exports to any country that aided Israel. On October 10, the United States began to resupply Israel with weapons and spare parts; one week later, the Arab producers announced retaliation.

By the time the embargo became effective, President Nixon and most senior policy officials in the White House were already preoccupied with the Watergate affair. Consequently, many of the initiatives developed to deal with the embargo and its aftermath were mandated by the Congress in response to constituent pressure. In the spring of 1973, the administration had unsuccessfully attempted to diffuse congressional action on an allocation measure. The Voluntary Petroleum Allocation Program was specifically created to address the spot shortages problem without the need for a massive congressionally mandated allocation effort. On October 2, the administration announced the establishment of a mandatory allocation program for propane. A similar program was announced for heating oil two weeks later. Ironically, the allocation regulations were perceived by the government as a means to solve some of the problems created by price controls.

The Emergency Petroleum Allocation Act was already winding its way through Congress before the embargo decision was made. The House passed, by a vote of 337 to 72, its version of the legislation on October 17, the same day the embargo was announced. The resulting price and allocation regulations would continue, under the guise of consumer protection, to deter domestic exploration and production activity, increase demand and subsequent import reliance, and cause shortages and distortions in the marketplace that were disproportionate to the actual cutoff of Arab oil.

The production curtailments resulting from the embargo reduced Arab oil supplies worldwide by approximately 5 MMB/D (from 20.8 MMB/D to 15.7 MMB/D) between mid-October and the end of the year. These reductions were partially offset by increased output from other producers, including Indonesia, Canada, Venezuela, Nigeria, and Iran. The resulting net non-communist world oil shortfall

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[3]Ohio Turnpike Commission vs. Texaco, 1 En. Mgmt. Rep. (CCH) Para. 9701 (Court of Common Pleas of Ohio, Cuyahoga County, June 13, 1973). Texaco had restricted the gasoline available to its company-operated stations on the Ohio Turnpike, and instituted a limit on the sale of gasoline to 10 gallons per automobile. These stations were operated under a contract with the Ohio Turnpike Commission that required Texaco to service the needs of all customers on the turnpike.

[4]Old oil was that produced from a property in production in 1972; new oil was from properties developed after 1972 or production that exceeded 1972 base levels. Prices for old oil were set at May 15, 1973, levels plus 35 cents (i.e., approximately $4.25 per barrel). New oil was allowed to be sold at $5.12 per barrel, the prevailing market price. The category of "released oil" was intended to provide incentives for incremental production as producers were allowed to release one barrel of old oil from price controls for every incremental new barrel produced from an old oil property (above 1972 base level output).

was consequently about 4 MMB/D, or 7 percent of pre-embargo consumption.

Following the onset of the embargo and the enactment of mandatory allocation legislation, the principal objectives of both the Congress and the government were to "equitably" distribute available supplies to consumers and to constrain price increases.

On October 16, the day before the embargo was announced, the Arab OPEC members increased their crude oil price from $3.01 per barrel to $5.12 per barrel. By the end of the year, the price had quadrupled to almost $12 per barrel.

The principal means selected by the administration to constrain oil price increases were the Phase IV price controls. A final two-week price freeze was imposed between October 15 and 31, 1973. However, just as the period was coming to an end, gasoline shortages began to appear. The shortages only served to underscore the perceived political need for allocation regulations, and, in retrospect, also contributed to the decision incorporated in the Emergency Petroleum Allocation Act to extend price controls for the oil industry long after the freeze was lifted for all other sectors of the economy.

Exclusive of price and allocation controls, the government had few alternatives to cope with the ensuing shortages. A number of demand restraint measures, both voluntary and mandatory, were imposed between November 1973 and January 1974 in an effort to induce conservation. These initiatives included lower thermostat settings, fuel switching (from oil to coal, where possible), reduced highway speed limits, odd/even days and minimum-fill gasoline purchase restrictions, and the voluntary ban on Sunday gasoline sales.

Despite these efforts, however, total petroleum product demand during the fourth quarter of 1973 was higher than that of 1972; gasoline demand for the quarter averaged almost 3 percent higher than the comparable 1972 period. Gasoline sales did not decline until shortages and long lines became evident early in 1974.

On December 4, 1973, the Federal Energy Office (FEO) was established by executive order. A successor agency, the Federal Energy Administration (FEA) was created by legislation in May 1974 with the mandate to develop national energy policy objectives and "promote stability in energy prices to consumers."[5] Both FEO and FEA were given responsibility for implementing the price and allocation regulations.

On January 15, 1974, the initial set of crude oil regulations was published in the Federal Register. Over the course of the next several years, the regulations would be amended and expanded several hundred times through a combination of legislative amendments, regulatory proceedings, and/or the issuance of "interpretive" guidelines.

A selected number of the major regulatory programs established over the next seven years are briefly outlined below. The impacts that these programs had on U.S. import dependence and vulnerability to the Iranian disruption experienced five years after the embargo are outlined later in this chapter.

Crude Oil Allocation: The Buy-Sell Program

In the interest of "sharing" available crude oil supplies to more evenly distribute the effects of the embargo shortfall, the government established a buy-sell allocation program for crude oil. Under the program, refiners with excess supplies were required to sell oil to refiners who needed additional supplies.

Initially, the program was set up to ensure that all refineries would be able to operate at some national average percentage of total capacity. The unreliability of capacity data eventually led regulators to use historical base period data on actual crude oil runs as a means for determining allocations. Under both schemes, however, since sales of additional barrels were transacted at mandated "average prices," sellers were unable to recoup the full cost of the last barrel that they previously had acquired. Consequently, refiners and importers that were successful in securing additional oil on the world market were now likely to have that oil allocated away, possibly at prices below what they paid to secure it. Conversely, refiners that had elected not to contract for long-term crude oil supplies and who were either unwilling or unable to locate needed feedstocks were now "awarded" allotments through the allocation system.

To the extent that crude oil transfer sales went from larger, more efficient refiners to smaller, less efficient processing plants, fewer refined products were ultimately made available to consumers. Thus, by discouraging additional imports and allocating the remaining scarce supplies to less efficient refiners, the regulations worked to aggravate rather than mitigate the effects of the embargo shortfall.

[5]Federal Energy Administration Act of 1974, P.L. 93–275, May 1974.

The Entitlements Program

As indicated earlier, federal price controls on domestic crude oil were first imposed in 1971. In August 1973, the Cost of Living Council promulgated Phase IV price regulations establishing a tiered price system for domestic production: "old" oil was price controlled and "new" oil was free of price controls. (Later, new oil was once again placed under price controls.) This two-tiered pricing system was designed to provide adequate price incentives to stimulate new crude oil exploration and production while concurrently holding average domestic crude oil prices below world levels in order to insulate consumers from the effects of higher prices.

By the end of the 1973–74 embargo, the combination of domestic price controls and the fourfold increase in world oil prices had created a significant disparity between the price of domestic "old" oil and imported crude oil in the United States. This differential in crude oil costs accordingly resulted in a wide range of prices paid by consumers for refined petroleum products.

Once the government had decided to address the embargo shortfall through the use of price and allocation controls, rather than by reliance on the marketplace, a means for "equalizing" the multi-tiered crude oil costs of refiners had to be developed for both equity and political reasons. The mechanism selected was the Old Oil Allocation or Entitlements Program. The purpose of the entitlements program was to equalize U.S. refiners' crude oil acquisition costs, by distributing the benefits of access to lower priced domestic crude oil proportionately to all domestic refiners, through a system of monetary rather than physical transfers.

As a procedural matter, the FEA calculated and published, on a monthly basis, a national average ratio of old oil supplies to total crude oil runs. Refiners were then issued entitlements equal to the product of this ratio and their adjusted crude oil receipts. Each entitlement gave a refiner the right to receive into inventory and refine one barrel of domestic old oil. Cost equalization was achieved by requiring various refiners to purchase or sell entitlements, based on whether their access to controlled domestic oil supplies was higher or lower than the national average.

Refiners with greater than average access to price controlled domestic oil were required to purchase entitlements. Refiners who used a disproportionate amount of foreign or uncontrolled domestic crude oil were required to sell entitlements. The FEA initially set the value of an entitlement as the difference between the average cost of imported oil and the average cost of price controlled domestic oil, minus 21 cents. The 21 cents, equal to the fee imposed on imported crude oil, represented an incentive to encourage the refining of domestic oil and to discourage the importation of higher priced foreign oil.

Because the entitlements program was "funded" through intra-industry transfers, rather than by government appropriations, the scope of the program was often readily expanded to address a variety of new problems. For example, because the entitlements program subsidized crude oil imports but not product imports, Caribbean refiners who supplied the U.S. East Coast with residual fuel oil produced from uncontrolled foreign crude oil were unable to compete with domestic refiners. Consumers on the U.S. East Coast were, therefore, adversely affected. As a result, the entitlements regulations were modified to correct this problem. Later in the program, entitlements awards or exceptions were made to encourage the production of heavy California crude and tertiary oil production. The program was also used to subsidize selected synthetic fuel projects.

The Small-Refiner Bias

The entitlements program also included a provision known as the "small-refiner bias." The small-refiner bias was, in theory, compensation awarded to small refiners to offset their lack of economies of scale and relatively higher operating and capital costs. Modeled after the sliding scale that had been incorporated in the Mandatory Oil Import Program (1959–73), this portion of the entitlements program partially exempted small refiners (those with 175 MB/D capacity or less) from entitlements purchase requirements or awarded them additional entitlements to sell. The amount of additional entitlements was scaled in an inverse relation to refinery runs so that the greatest benefits were derived by refiners running 10 MB/D or less.

In the first two years after the small-refiner bias program was implemented, 24 new refineries of less than 30 MB/D capacity were built or reopened in the United States. During the seven years of U.S. price and allocation controls, more than 60 refineries of less than 30 MB/D capacity were built, over two-thirds of which were under 10 MB/D. The bulk of these refineries were built only to take advantage of the subsidies available to the operator rather than to contribute to supplies of refined product.

The small-refiner bias was not the only regulatory program to produce unintended results. As a number of the selected programs evolved over time and in the context of changing supply conditions, new initiatives were added in response to special interests or to achieve other specific, short-term objectives, many of which were beyond the scope of the original program intent. The tertiary incentive program, the distillate and resid entitlements programs, and the California heavy oil program, all of which were perceived to have had positive effects on either crude oil or heating oil supplies, are examples of this evolution.

Summary of Government Responses

Because of the degree of detail associated with many of the regulatory programs and the level of intrusion and interference that they created in the marketplace, modifications and expansions of the various regulations often resulted in new sets of winners and losers.

Despite the intent of protecting consumers and equitably distributing scarce supplies, the price and allocation controls discouraged needed investment in exploration, production, and refining ventures; encouraged rather than discouraged demand, by artificially restraining prices; subsidized the importation of and increased reliance on foreign oil; and encouraged imprudent and inefficient distribution and market behavior. The average price of old oil in 1974, before royalties and state taxes, was $6.87 per barrel, while imported oil averaged $12 per barrel.

Additionally, the suspicion and alienation shared in turn by both government and industry officials undermined the effective partnership approach to addressing supply and distribution problems that had proved to be so effective during the World War II and Korean War efforts. At its height, this political "conflict of interests" concern precluded the government's hiring of employees with any recent prior oil industry experience or affiliation.

A number of the Arab OPEC members lifted the embargo against the United States in March 1974, but Libya, Syria, and Iraq continued their curtailment policies until summer. However, the widespread belief that the U.S. oil industry had caused or at least contributed to the crisis prompted the Congress to extend both the price and allocation controls well beyond the "crisis period."

CONTINUED U.S. OIL IMPORT DEPENDENCE PRIOR TO THE IRANIAN CRISIS (1975–78)

Because of the lag time in developing and implementing regulations and programs to address the embargo crisis, the bureaucracy at both the federal and state levels was expanding just as supplies were coming back into balance. By the fall of 1974, FEA had been authorized to administer both the allocation and price regulations formerly administered by the Cost of Living Council. The industrialized nations of the world had formed a pact for sharing information and supplies through the International Energy Agency (IEA). The entitlements program was established to address the equity issues resulting from the disparity between uncontrolled world oil prices and those capped under domestic price controls. By now, the Cost of Living Council's wage and price controls had expired, except for those imposed on the oil industry.

The disruption caused by the embargo had ended and the administration favored the termination of the troublesome controls. In his January 1975 State of the Union Address, President Gerald Ford called for more favorable changes to the tax code for oil and gas producers and the elimination of controls in order to make the nation "invulnerable to future cutoffs of foreign oil . . . ."[6]

The Congress, however, bolstered by public opinion polls showing a general distrust of the oil industry, instead proposed and adopted several punitive pieces of legislation. The depletion allowance was eliminated for major oil companies and a number of divestiture bills were introduced in both houses of Congress.

The Emergency Petroleum Allocation Act, which was scheduled to expire on February 28, 1975, was extended through August. In July, President Ford unveiled a plan to phase out controls on oil over a 30-month period. He also proposed the adoption of a "windfall profits" tax to ensure that domestic producers would not derive the full benefits of higher prices that resulted from the embargo conditions and subsequent price adjustments by the OPEC members.

However, by year end, the passage of the Energy Policy and Conservation Act (EPCA) eliminated any chances for rapid decontrol. The legislation granted the President standby authority to impose rationing, to reduce demand through conservation initiatives (including the establishment of auto fuel efficiency standards), and to fulfill U.S. obligations under the IEA agreement. The measure also established the creation of the Strategic Petroleum Reserve

[6]"Address before a Joint Session of Congress Reporting on the State of the Union, January 15, 1975." Public Papers of the Presidents: Gerald Ford, 1975. Washington, DC: GPO, 1977, p. 42.

(SPR). The bill's oil pricing provisions reestablished price controls on new, released, and stripper well oil, categorized as "upper tier" oil, rolled back the price for domestic old "lower tier" oil, and extended the controls for another 40 months.

The statutory extension of price and allocation controls beyond the actual crisis period perpetuated existing supply and distribution problems. Further, by keeping prices artificially low, domestic exploration and production activity was impeded while consumption was encouraged.

At the same time, environmental regulations, such as the Mine Safety and Clean Air programs, skewed boiler demand to low sulfur residual fuel oil imports and natural gas rather than coal. Lower controlled gasoline prices prompted a resurgence of consumer demand for bigger cars. Environmental restrictions, offshoots of the 1969 Santa Barbara spill, resulted in delays in offshore exploration and production.

Between 1973 and 1977, domestic crude oil production declined from 9.2 MMB/D to 8.2 MMB/D (see Figure 28). Domestic gas production also declined by 12 percent. However, following the 1973–75 recession, consumption continued to grow and imports increasingly filled the gap. Between the time of the oil embargo and the election of President Carter, U.S. dependence on foreign oil had grown from 35 percent to 46 percent of consumption.

While campaigning for the presidency, Jimmy Carter had promised natural gas decontrol and replacement cost pricing for oil. However, following the natural gas curtailments of the winter of 1976–77, upon assuming the presidency in January 1977 he was confronted with the political reality that neither goal would be immediately achievable (see section entitled "Significant Factors Affecting the Development and Use of Natural Gas").

On April 20, 1977, in a nationally televised address before the House and Senate, President Carter unveiled the National Energy Plan. The goals of the plan were to reduce the annual growth rate in energy demand to below 2 percent and to cut oil imports to below 6 MMB/D. The objectives were to be met through a series of initiatives that included conservation, fuel switching, synfuels development, a new natural gas pricing regime, and the adoption of the Crude Oil Equalization Tax. Under the proposal, new oil would gradually rise to market levels and production from enhanced oil recovery (EOR) projects and stripper wells would be free of controls. Old oil would remain under price controls with increases pegged to inflation adjustments.

The House of Representatives, with the aid of some extraordinary procedural maneuvers that substantially altered traditional committee jurisdiction, passed the National Energy Act intact in less than six months. In the Senate, the plan stalled due to opposition over the Crude Oil Equalization Tax, the centerpiece of the oil price plan.

In October of 1977, a new cabinet level agency, the Department of Energy, was created and James Schlesinger was confirmed as the first Secretary of Energy.

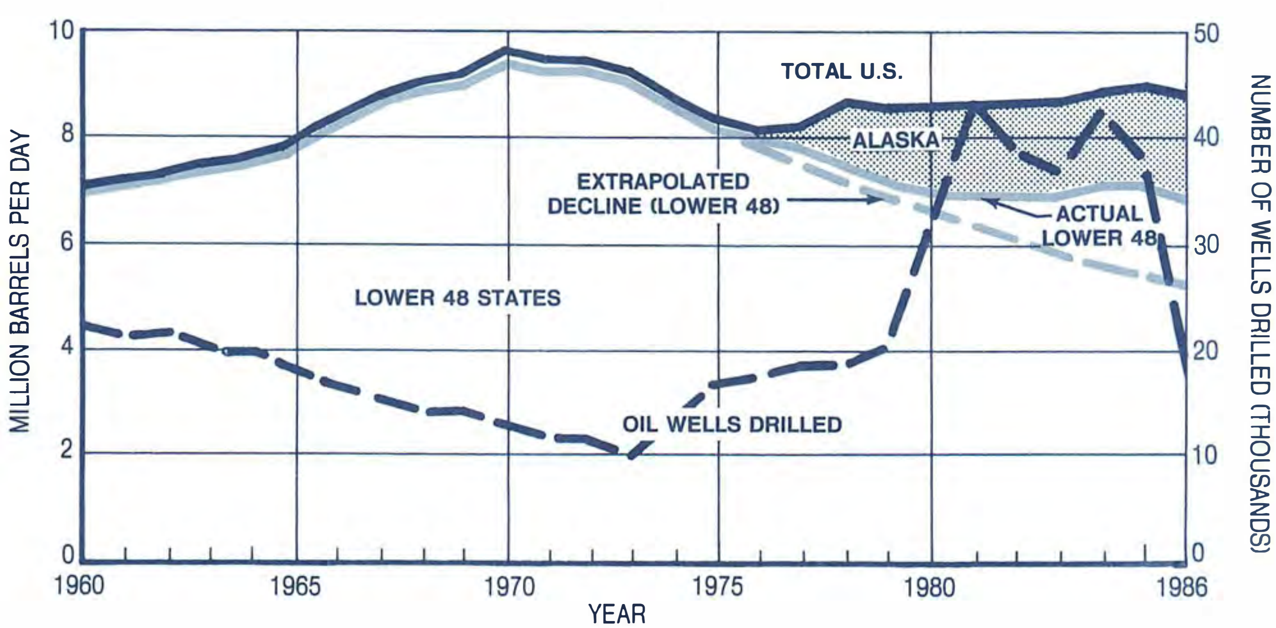

Figure 28. U.S. Crude Oil Production, Actual and Normal Decline, and Oil Wells Drilled.

In July 1978, while attending the Bonn Economic Summit, President Carter pledged that by the end of 1980, U.S. oil prices would be at world market levels. Later that summer, the administration began developing plans to decontrol domestic crude oil prices. The extension of price controls under EPCA was scheduled to expire the following June.

At the end of October 1978, Congress passed its "revised version" of the National Energy Plan, including as separate pieces of legislation the Natural Gas Policy Act and the Powerplant and Industrial Fuel Use Act. The Crude Oil Equalization Tax provisions were stripped from the package as were those provisions deregulating oil prices.

Within two weeks of the passage of the National Energy Act, the Iranian revolution and the mass exodus of that country's oil field operators resulted in a precipitous decline in Iran's oil output and exports. Between September 1978 and January 1979, Iranian production dropped from 5.6 MMB/D to almost nothing.

GOVERNMENT RESPONSES TO THE IRANIAN SHORTFALL

Prior to the curtailment of Iran's oil production, world oil prices had remained stable since the 1973–74 embargo. Between 1974 and September 1978, crude oil prices had risen less than the average rate of inflation in the industrialized countries. In September 1978, the price for Saudi light was $12.70 per barrel (U.S. landed cost of $14.03 per barrel), only about a dollar above OPEC's posted price in January 1974. Composite U.S. oil prices in the fall of 1978 were $4 per barrel below the Saudi price due to controls; U.S. stripper oil, now free of domestic price controls, was sold for $14.03 per barrel. Old oil averaged only $9 per barrel in 1978. U.S. import dependence in the fall of 1978, prior to the Iranian revolution, was about 8.5 MMB/D, or 45 percent of consumption.

Disruptions in the flow of Iranian oil began with strikes in the Abadan refinery and neighboring oil fields on October 20, 1978. As the strikes became more widespread, production continued to decline until December 26, 1978, when all oil exports were terminated. Oil production during January and February 1979 was not even sufficient to meet Iran's internal needs.

Prior to the cutbacks, the United States was the second largest importer (after Japan) of Iranian oil. For the first nine months of 1978, import levels approximated 750 MB/D, representing about 9 percent of total oil imports and 4 percent of total U.S. petroleum demand. At the time of the disruption, Iran was the world's fourth largest oil producer and the second largest exporter of crude oil.

Iran resumed exports of crude oil at about 2 MMB/D in March of 1979. By June, Iran's oil output was back to 75–80 percent of the predisruption levels and exports approached 3.5 MMB/D.

As indicated earlier, the loss of Iranian oil during the November 1978–June 1979 period was partially offset by increased production elsewhere in the world. Although the resulting loss of world oil supplies during the revolution was between 2 and 2.5 MMB/D, the U.S. share of the total supply shortfall approximated 200 to 400 MB/D at any given time.[7]

Ordinarily, a shortfall of this magnitude should have produced only minor disruptive effects, and certainly not a tripling of oil prices. In retrospect, however, the convergence of a variety of factors, including price and allocation controls, low pre-crisis inventory levels worldwide, the prevailing uncertainty regarding the duration and magnitude of the crisis, the curtailment of third party sales, and consumer behavior and panic buying (evidenced by tank topping, supply hoarding, and bidding up prices for spot cargos of oil), produced an array of consequences totally out of line with the size of the disruption.

Panic buying was not limited to U.S. consumers. In short order, major industrialized nations (e.g., Japan) that had been particularly dependent on Iranian oil supplies became active in the spot market, bidding up prices for crude oil and product cargos.

In December 1978, OPEC announced an official price increase of 60 cents per barrel. However, between October and the end of the year, Rotterdam spot market prices had already doubled from $10.50 per barrel to almost $22.50 per barrel.

In the United States, petroleum consumption was peaking at 18.9 MMB/D, yet total primary stocks of crude oil and refined products were 7 percent below 1977 levels. Crude oil inventories were less than 310 million barrels, close to the projected minimum operating level for primary stocks. Gasoline consumption for the year was at a record pace and, by the end of the summer driving season, motor gasoline stocks had been depleted to their lowest levels since the embargo.

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[7]U.S. General Accounting Office, *Report to the Congress by the U.S. Comptroller General on the Iranian Oil Cutoff.* Doc. #EMD 79–97, GAO, September 13, 1979.

As refineries pressed to maintain higher gasoline output levels as late as December, distillate stocks were necessarily drawn down to keep up with the seasonal incremental demand for home heating oil.

At the outset of the crisis, the Carter administration attempted to minimize the shortfall by encouraging a variety of conservation measures. The Department of Energy estimated that the combination of compliance with the 55 mile per hour speed limit, reduced discretionary driving, and lower thermostat settings could save up to 500 or 600 MB/D, thus making the shortage manageable. Fuel switching from oil to gas and electric power wheeling initiatives were recommended as means to save additional fuel, theoretically more than offsetting the loss of Iranian supplies.

Additionally, the administration proposed the adoption of several mandatory conservation measures, including a plan for reduced heating in commercial buildings and a ban on unnecessary outdoor lighting, including Christmas lights. A standby gasoline rationing program was also proposed. Of these measures, only the mandatory commercial thermostat setting proposal was adopted by Congress, as part of the Emergency Energy Conservation Act of 1979. Conservation programs were also developed by various state and local jurisdictions.

Finally, as required by EPCA and in response to prevailing congressional concerns relative to the inflationary effects of subsequent oil price increases, controls on crude oil and gasoline remained in place for the duration of the crisis. Earlier attempts at decontrolling motor gasoline had been rejected by Congress. Continued controls severely limited the government's ability to address the supply imbalances by using measures directed predominantly at the demand side of the equation.

In an abbreviated effort to restrain runaway world oil prices, the government also urged domestic refiners and importers not to bid up the prices for spot cargos of crude oil. The rationale for this action was twofold—to alleviate some price pressure on spot market sales by removing potential bidders from the process, and to allow other consuming nations the short-term benefits of the availability of incremental supplies in order to get their internal supply/demand balances somewhat under control.

The effort was short-lived, however. The spot market continued to be active, with Japanese and European traders continuing to bid up the price for oil. Some U.S. companies that felt obliged to secure foreign supplies to meet their customer demands also continued to be active in spot purchases. By May 1979, in the face of looming product shortages, the administration reversed its earlier policy decision and encouraged U.S. refiners to re-enter the spot market.

During the spring of 1979, the administration, in anticipation of the possibility of a protracted shortage, also urged refiners to use their inventories sparingly and to rebuild stocks whenever possible. The cumulative effects of these decisions and the various "quirks" of the allocation regulations were predominantly responsible for the gasoline shortages that developed over the next four months.

Data published by government sources after the Iranian crisis ended indicated that total oil supplies available through the first seven months of 1979 averaged only about 1 percent less than the volume of total products supplied during the same period of the previous year. However, as a consequence of the low pre-crisis stock levels and the consequent efforts of refiners and other consumers to rebuild oil inventories throughout the crisis period, supplies available to consumers were noticeably reduced. Ironically, the most obvious manifestations of the Iranian shortfall in the United States, i.e., gasoline shortages and oil price increases, occurred after the actual supply shortfall had ended.

Gasoline lines first appeared in California in May of 1979. For the next three months, the phenomenon was repeatedly observed in various locations throughout the nation, primarily in metropolitan areas. Surpluses continued to exist in rural, resort, and farm areas. The hidden culprits behind the gas lines, at least in part, were the allocation regulations—the use of outdated historical base periods as a means for distributing supplies, the identification and expansion of priority users, state set-aside programs—and "tank topping" by panicked consumers.

How Selected Allocation Regulations Contributed to Shortages and Gas Lines

It should be noted at the outset that the only major product shortages evidenced by the Iranian cutoff involved supplies of motor gasoline. Products that were uncontrolled were generally in adequate supply throughout the crisis period.

Crude Oil Allocation: The Buy-Sell Program

The allocation of crude oil among refiners contributed to the gasoline shortages in two principal ways. First, to the extent that oil was transferred from larger refiners with high gasoline productive capacity to smaller refiners with little gasoline-making capability, the result of the transfer was a net loss in terms of gasoline supplies. Further, the removal of incremental barrels from the distribution system of major gasoline refiners and marketers put additional pressure on the ability of the system to service regions in short supply.

The Use of Historical Base Periods

The adoption of an allocation mechanism to equitably distribute scarce supplies necessarily requires the use of some base period for computing allocation fractions for future months. The more current the base period, the more likely that it will reflect, on a pro-rata basis, recent changes in consumption patterns. However, recognizing that crisis consumption patterns will, by definition, not coincide with "normal" base period data, the formulation of allocation fractions will necessarily be inexact.

As in 1974, the government's program for allocating scarce supplies of motor gasoline in response to the Iranian shortfall centered around the use of a historical base period. Consequently, when gasoline supplies became tight during the early spring of 1979, the initial allocation volumes used were based on the volumes of gasoline purchased during the corresponding months of 1972, with some limited adjustments.

The use of this "outdated" base period caused predictable results. In some cases, suppliers were assigned to customers that they had not served since 1972. Further, the sales volume data often failed to reflect the growth adjustments that particular regions, states, and metropolitan areas had experienced since the embargo.

To redress this oversight, the Department of Energy updated the gasoline allocation base period from calendar year 1972 to a more current, pre-Iranian revolution base and added special provisions to allow for "unusual growth." Despite these attempts at updating, however, the program was never able to adjust to the problem of rapidly changing markets and consumption patterns.

Because of consumer fears of being unable to buy gasoline on any given day at any given location, many motorists altered summer vacation plans or remained at home. As a consequence, remote resort and low growth areas were often awash with gasoline while residential and high growth areas were faced with shortages.

State Set-Aside Allotments

In response to the Iranian shortfall, state governments, concerned with their ability to ensure that state police, hospitals, fire departments, and municipal, county, and state officials had enough fuel supplies, lobbied for and received special state set-aside volumes. Under the set-aside program, suppliers were required to withhold between 3 and 5 percent of their total supplies from their normal distribution channels in order to make those volumes available to "special need" consumers identified by the state.

The withholding served to further reduce the amount of available, allocatable supplies that otherwise could have been used to mitigate the effects of the shortfall on the general public. Further, to the extent that the set-aside volumes were not used by the state during any particular month, the supplies were then to be hurriedly redistributed into normal channels.

The Identification of Priority Users

In addition to the base period allocations and state set-aside requirements, suppliers were also required, in special cases, to supply selected "priority users" (e.g., farmers, hospitals, police, and fire fighters) with 100 percent of current needs.

As expected, the priority user classification became a favorite target for abuse. For example, Special Rule No. 9 allowed farmers to receive all the diesel fuel they needed in order to complete their spring planting. In response to this "preferential" treatment, the truckers went on strike, refusing to carry farm goods to market and closing down major portions of the interstate highway system to highlight their predicament. Shortly thereafter, Special Rule No. 9 was amended to include truckers among the class of priority users entitled to 100 percent of their diesel fuel needs.

The combination of special exemptions and the set-aside programs reduced the level of available allocation volumes to the general public, exaggerating the general shortage situation and fueling the tank-topping response of the average consumer.

The Impact of Tank-Topping

Prior to the advent of consumer panic, the average U.S. motorist drove with his gas tank between one-third and one-half full. With the coming of long lines and odd/even day rationing, consumption patterns began to be drastically altered so that "tank-topping" became the rule rather than the exception.

In 1978, there were some 150 million motor vehicles registered in the United States. If only half of the owners of those cars and trucks adopted the tank-topping practice, assuming a 14 gallon tank capacity, there would have been an additional 13 to 18 million barrels of fuel sitting in storage in personal vehicles at any given time and consequently unavailable for more general distribution.

Crude Oil Decontrol

Under provisions of EPCA, the nondiscretionary authority for continuing price controls on domestic oil was scheduled to expire in May of 1979. Prior to that time the administration had to choose whether to extend controls for an additional 30 months or seek deregulation on either an immediate or a more gradual phase-out basis.

Early on, in response to the shortfall, Secretary of Energy Schlesinger and some members of the Carter administration recognized that price and allocation controls were not only ineffective in correcting the Iranian supply problem but, in fact, were worsening the crisis. They believed that the time had come for U.S. consumers to recognize the true costs of energy. Attempts at convincing the public and the Congress that this was the case, however, caused substantial political damage.

During the previous summer, before the Iranian revolution took place, the Department of Energy was developing options for a phased deregulation plan. With the advent of the Iranian crisis, however, prospects for decontrol were not favorable.

On April 5, 1979, President Carter announced his program of phased decontrol and the creation of an Energy Trust Fund. Under the deregulation plan, beginning on June 1, controls would gradually be lifted over a 30-month period. The phased deregulation schedule was selected in the interests of minimizing the cost to consumers and the inflationary effects of immediate decontrol.

To prevent domestic oil companies from reaping "excessive, windfall profits" as a result of price deregulation, a special tax was proposed to capture 50 to 70 percent of the expected increase in revenues. The tax would then be used to subsidize the development of alternative energy sources, mass transit projects, and low income energy assistance credits.

The decontrol formula itself was relatively simple. As an incentive to encourage new exploration and production activity, newly discovered oil was to be decontrolled on June 1. Lower tier or old oil would be released to upper tier levels at the rate of 1.5 percent per month. Upper tier oil would be allowed to gradually rise to world price levels, also in monthly increments. To stimulate investments in EOR projects, the proposal allowed producers to release certain lower tier oil to help pay for the EOR effort. All controls were to be eliminated on October 1, 1981.

Between 1979 and 1985, the combination of higher oil prices and the targeted investments in new drilling and EOR projects resulted in record level rotary drilling rig activity (1981) and an increase in total domestic crude oil production from 8.6 MMB/D to 9.0 MMB/D. During the period, incremental production in the lower 48 states was more than sufficient to offset the historical decline normally associated with reservoir depletion and, in fact, may have contributed as much as an additional 1.5 to 2.0 MMB/D of daily U.S. oil production (see Figure 28).

In the spring of 1980, Congress enacted the Windfall Profit Tax, a measure that both congressional and industry officials privately conceded as the political "quid pro quo" for having achieved decontrol.[8] The tax effectively capped producer returns on investment, but more importantly set a precedent for Congress to tax revenues rather than income.

The Congress also adopted, as part of a more delayed energy response plan, the Energy Security Act, which established a fast track, government-sponsored synfuels development effort.

Later that year (1980), the Department of Energy released a response plan for reducing U.S. vulnerability to supply cutoffs in the future.[9] The report called for the adoption of a variety of supply and conservation initiatives, including: the return to a system of free-market pricing for both oil and gas, the expansion of purchases for the SPR, government assistance in developing alternative fuels, a revamping of the leasing system to allow better access to resources located on federal lands, improved energy-efficiency programs, and the diversification of oil import sources. It is significant to note that even in the face of the potentially volatile supply situation associated with the Iran/Iraq conflict, the administration refused to backtrack on its commitment to decontrol.

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[8]U.S. Congress, *Conference Report: Crude Oil Windfall Profits Tax Act of 1980*. House Report 96-817 (96th Cong., 2nd Sess.), March 7, 1980, pp. 92–115.

[9]U.S. Department of Energy, Office of Policy and Evaluation, *Reducing U.S. Oil Vulnerability, Energy Policy for the 1980s*. An analytical report to the Secretary of Energy, November 10, 1980.

On January 28, 1981, a newly inaugurated President Ronald Reagan, fulfilling a campaign pledge, by executive order terminated the remaining controls on domestic oil, accelerating the phased decontrol schedule established by President Carter almost two years earlier.

The Post-Decontrol Environment (1981–85)

In direct response to the substantial increases in world oil prices following the Iranian crisis and the elimination of domestic oil price controls, U.S. drilling activity reached record levels in 1981. As a function of this increased activity, domestic crude oil production rose by 400 MB/D between 1979 and 1985, from 8.6 MMB/D to 9.0 MMB/D. The majority of this net increase resulted from the combination of increased production in Alaska; the maintenance of production in the lower 48 states over and above the normal reservoir decline rates; and incremental new supplies from enhanced recovery and new production efforts.

Domestic consumption of oil and gas—similarly responding to price changes, increased efficiency, and conservation—declined over the same period by 15 percent. Net oil imports declined over the same period from 8.0 MMB/D to 4.2 MMB/D, a decrease of over 47 percent from 1979 levels.

Consistent with the reduced demand for oil products, increased competition, and the loss of special programs such as the small-refiner bias, the post-decontrol environment produced a substantial shutdown of domestic refining (distillation) capacity. Between January 1, 1981, and January 1, 1986, the U.S. refining industry experienced a net loss of 3.2 MMB/D of operating and distribution capacity, including the shutdown of 120 refineries.

In an apparent attempt to reduce U.S. vulnerability to another protracted oil supply disruption, domestic refiners and importers dramatically shifted their import sources. At the same time, the SPR was being more than quadrupled in size, from 91 million barrels in 1979 to 493 million barrels at the end of 1985.

In 1979, total crude oil and product imports from OPEC nations accounted for some 5.6 MMB/D, about 70 percent of total import volumes. Imports from Middle East OPEC represented 2.1 MMB/D of that total. By way of contrast, imports from Western Hemisphere nations (Mexico, Canada, and OPEC member Venezuela) accounted for 1.7 MMB/D, or less than 20 percent of the total.

By year-end 1985, imports from the Western sources made up some 44 percent (2.2 MMB/D) of U.S. oil imports. Imports from Saudi Arabia had declined by over 1 MMB/D during this period, and imports of total OPEC and Middle East OPEC oil registered only 1.8 MMB/D and 300 MB/D, respectively.

SIGNIFICANT FACTORS AFFECTING THE DEVELOPMENT AND USE OF NATURAL GAS

Growth of Natural Gas as an Energy Source

A brief background of the development of natural gas as a major source of energy in the United States is helpful to understand government actions that have occurred since the 1940s. Until the late 1940s, gas found in combination with oil reserves was often either flared or burned on site to generate energy to support oil production.

Prior to the 1930s, commercial development of gas usage was limited by the proximity of the user to the production site. Regional, small diameter pipelines often connected the early gas finds to municipal utilities in nearby towns. As the technology for piping gas long distance improved, these delivery systems were expanded as gas proved to be clean, safe, and inexpensive.

During World War II, demand for natural gas increased, as did the transmission systems necessary to deliver the fuel to market. By 1945, the total domestic gas pipeline system—including gathering, transmission, and local distribution lines—reached over 200,000 miles in length. Because of various regulatory restrictions and the fundamental differences between the businesses of producing and transporting gas for sale, integration became the exception rather than the rule in the gas industry, and three distinct segments evolved—gas production, transmission, and distribution.

In 1940, total gas consumption was 3 trillion cubic feet (TCF), representing 10 percent of all energy consumed. By 1950, gas consumption had doubled—to 6 TCF—and represented 18 percent of U.S. energy consumption. By 1960, gas consumption had more than doubled again—to 12 TCF—and gas had captured 28 percent of the energy market. In 1972, coincident with tight supplies of fuel oil and propane, gas use peaked at 22 TCF, which amounted to 32 percent of domestic energy consumption.

Early Regulation of Gas Transportation, Sales, and Wellhead Prices

The Natural Gas Act of 1938

In 1934 and 1935, a 96-volume report was released by the Federal Trade Commission contending that a small number of companies dominated the transportation of natural gas. As a result of this report and other perceived natural gas problems, Congress adopted the Natural Gas Act (NGA) of 1938.

The NGA gave the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission (FERC), the authority to regulate the interstate transportation and sales for resale of natural gas. The Act specifically excluded from the FPC's jurisdiction "the production or gathering of natural gas" and its "local distribution." Accordingly, the Act was initially interpreted by the FPC and the courts as precluding FPC jurisdiction over wellhead prices.

The Phillips Decision

In a test of the question of jurisdiction over producers, the FPC ruled in 1951 that Phillips Petroleum, a natural gas producer not involved in the interstate transportation of gas, was not a natural gas company as defined by the NGA. Therefore, the FPC ruled that it had no jurisdiction over Phillips or any other independent producer or gathering company.[10]

The FPC's decision in the *Phillips* case was appealed to the Supreme Court in the case of *Phillips Petroleum Company vs. Wisconsin.* The court held that the NGA required regulation of the price of natural gas at the wellhead, but did not provide the FPC any guidance as to how it should regulate wellhead prices pursuant to the NGA.

The Supreme Court found that the exemption in the NGA for those engaged in "production or gathering of natural gas" did not apply to Phillips, since the interstate sales in question took place after the gathering and/or production functions and constituted a "sale for resale" within the meaning of the NGA. The Supreme Court applied the production and gathering exemption only to the "physical process" of producing and gathering gas, and not the "sale for resale." In addition to forcing the FPC to begin a long series of decisions setting prices for interstate sales of gas at the wellhead, the decision for the first time created a "dual market" for natural gas—with price controlled gas flowing in interstate commerce, and market priced gas sold within producing states (the intrastate market).

In the *Panhandle Eastern Pipeline* case in 1954, the commission approved Panhandle's request to allow commodity (market based) prices for the gas that it produced. The commission pointed out the short-term irrationality of multiple prices for gas coming from different wells but going to the same consumers. From a long-term perspective, the commission concluded that an arbitrary, depressed price based on short-run cost would tend to accelerate consumption and fail to encourage future exploration. However, an appellate court overruled the FPC (the Supreme Court declined to review the case) and held that costs must remain the "point of departure" for federal rate regulation of pipelines (*City of Detroit vs. FPC*, 1955).

Early FPC Wellhead Pricing Decisions

Forced by the *Phillips* decision and constrained by the *City of Detroit* ruling, the FPC undertook the task of setting ceiling prices for natural gas at the wellhead. Until approximately 1960, the FPC itself did little to implement the regulation of independent producers, in the belief that Congress would override the *Phillips* decision. Efforts were made to modify the court's decisions through legislation in every session of Congress from 1954 through the mid-1970s. No legislative attempt was successful until the enactment of the Natural Gas Policy Act of 1978.

Company-by-Company Regulation

Initially, the FPC attempted to regulate the wellhead price of gas on an individual producer "cost-of-service" basis. Based on this standard, the FPC employed the cost-of-service methodology, traditionally used in utility rate regulation, for its wellhead price regulation. In general, the cost-of-service pricing methodology provides a rate of return based on net investment plus depreciation allowance and production costs, rather than the market value of the commodity or its replacement cost.

The sheer magnitude of this company-specific approach was both administratively unmanageable and impractical. By 1960, the

[10]Federal Power Commission, "In the Matter of Phillips Petroleum Co." Opinion 217, 10 FPC 246 (1951).

FPC case backlog approximated 3,000 cases.[11] Until the *CATCO*[12] decision by the Supreme Court in 1959, the FPC made no attempt to regulate the price of newly sold gas. After that decision, the FPC imposed price restrictions on the sale of new gas to "hold the line" on prices until geographical area ceiling rates could be established.

Area Regulation

Consequently, in 1960, the FPC discarded company-by-company regulation, and in its place began to regulate producers by determining "just and reasonable" rates on an area basis. Under the area-rate system, uniform wellhead price ceilings were set for all gas produced within a specific geographical producing area. Ceilings were based on average production costs and investment expenditures made by producers in that area.

The FPC chose the Permian Basin, located in portions of Texas and New Mexico, for its first area-rate proceeding. Proceedings in the *Permian* case lasted five years, and the commission's 1965 decision was not confirmed by the Supreme Court until 1968. Other area-rate proceedings took much longer. For example, the *Southern Louisiana* case began in 1961 and was not finally decided by the Supreme Court until 1974.

A distinguishing feature of the commission's *Permian Basin* order was the use of "vintaging," a two-tier pricing system for "old" and "new" gas. The commission believed that allowing higher incentive prices for new gas would encourage producers to engage in further exploration, while concurrently preventing windfall profits from the sale of old gas. While both ceiling prices were cost-based, "old" and "new" gas were priced substantially below the market value of the gas to the consumer, and market demand expanded rapidly. Interstate pipeline systems, aided by a guaranteed rate of return, were built and expanded to meet the demand, and consumption grew rapidly.

Natural Gas Shortages

Under the effects of FPC regulation, it took just 20 years of low prices and rapid demand growth to transform natural gas from an almost valueless by-product to a scarce commodity. Because of the relatively low price of natural gas, consumption grew almost fourfold between 1950 and 1970. But the same low prices failed to elicit sufficient exploration drilling, and the nation found itself moving quickly toward a shortage situation. During the 1960s, prices remained relatively flat, while the costs of new exploration and production rose. The watershed year was 1968—the first year when production exceeded reserve additions. Shortly thereafter, the warning signs began to emerge. A moratorium was placed on new gas hookups, and limited interruptions in service began to appear. In late 1973, domestic natural gas production began to decline. By 1974, service curtailments for industrial customers in interstate gas markets were widespread. Curtailment, measured in terms of contracted supply obligations that went unfulfilled, reached 16 percent nationally and was measurably higher in particular areas. By 1976, production had declined by 12 percent from its 1973 peak. Figure 29 compares natural gas production and reserve additions in the 1960–86 period.

At first, price differences between gas sold in the interstate and intrastate markets were minimal. Because the FPC would not allow more flexible contract terms, and because it insisted that wells once used to produce gas for interstate sale be perpetually dedicated to the interstate market, producers opted to sell new gas to the intrastate market. Once shortages began to occur, intrastate prices rose in an attempt to bring supply and demand back into balance. However, rigid, cost-based pricing by the FPC prevented this market mechanism from working in the interstate system, and shortages spread throughout most of the nation.

At the same time, environmental regulations and the relatively low price of gas stimulated increased demand for gas by residential and industrial customers in the interstate markets, further exacerbating the shortages.

Gas Curtailments

In 1968, although the average price of natural gas sold in the intrastate market was below that of comparable gas sold in the interstate system, the prices for newly contracted intrastate gas were 18 percent higher than newly contracted interstate gas. This differential widened in the early 1970s and peaked in 1975 when the price of new contracts for unregulated intrastate gas was nearly two-and-one-half times the price of gas sold in the interstate market.[13]

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[11] U.S. Congress, *Natural Gas Policy Act Amendments of 1983*. Senate Report 98-205 (98th Cong., 1st Sess.), July 29, 1983, p. 5.

[12] A partnership of Cities Service, Atlantic, Tidewater, and Continental.

[13] U.S. Congress, *Natural Gas Policy Act Amendments of 1983*. Senate Report 98-205 (98th Cong., 1st Sess.), July 29, 1983, p. 6.

Market and Outside Forces

The warning signs for the shortages became evident in 1968, when for the first time consumption in the interstate market exceeded new reserve additions and dedications. The oil embargo and subsequent OPEC price increase of 1973–74 increased the relative price differential between imported oil and natural gas. Demand for gas rapidly increased at the same time that easily producible and low cost domestic supplies were diminishing. In the absence of rapid price responses, the supply and demand of interstate natural gas was thrown completely out of balance. Because of cumbersome regulatory procedures, the FPC was unable to respond quickly enough to these changes. Moreover, the commission had to deal with vocal members of Congress who contended that the gas shortage was fictional rather than real, created artificially by producers to force the removal of price controls.

GOVERNMENT RESPONSES TO THE NATURAL GAS SHORTAGES AND CURTAILMENTS OF THE 1970s

During the 1970s, the FPC tried several methods to increase the flow of gas in the interstate market. In response to industry cash flow concerns and their impact on exploration and production expenditures, in 1970 the commission issued Order 410, which enabled producers to receive advance payments from interstate pipeline systems for committing gas supplies. These cash advances were included in the pipeline's rate base. The FPC also attempted to exempt small producers from federal regulation, but this action was overturned by the Supreme Court in 1974.

In spite of the substantial regulatory lag in the area-rate cases, no serious supply problems occurred during the 1960s, basically for two reasons. First, adequate gas supply existed to meet still developing demand. Until 1968, annual reserve additions exceeded production, and although the finding rate and reserve-to-production ratio were declining, interstate proved reserves and deliverability were still high because of the net additions to reserves made over the previous 20 to 30 years. Second, producer revenues, though declining, were still sufficient to finance continued exploration and production activity, but the activity was declining.

In 1974, the FPC altered its rate setting methodology by employing a single national ceiling price for the first time. This change was undertaken by the commission in explicit recognition of the fact that the wellhead price regulations were holding the price of interstate gas artificially low, thereby adversely affecting supply and creating availability problems in the interstate market.

In June 1974, the FPC issued Opinion 699, establishing a uniform price of 42 cents per thousand cubic feet (MCF) for new natural gas. This price applied to all gas in the lower 48 states, both onshore and offshore, from wells newly begun or reserves newly committed to the interstate market after December 31, 1972. Upon rehearing, almost two years later, the commission revised the price to 53 cents and extended its application to flowing gas upon expiration of existing contracts. The commission found perpetual vintage pricing an "anachronism" and decided to abolish it on a gradual basis as contracts expired. Opinion 699 also provided for biennial review to "determine if the rate was sufficient to bring forth the supply of gas." New gas would henceforth be priced at the new rates established by each review, so as not to create multiple vintages. Gas from wells drilled prior to 1973 continued to be regulated based on the historical cost of service.

On July 27, 1976, the FPC further addressed national rates in the first "biennial review," by issuing Opinion 770. In deriving the rates under Opinion 770, the FPC: (1) modified the cost-based rate method to include a component for federal income taxes (previously employed methodologies assumed that producers incurred no tax liability); (2) established a three-tier price system with the highest rate at $1.42 per MCF, escalating at 4 cents per year, for gas produced from wells commenced on or after January 1, 1975; (3) vintaged the gas from wells dedicated to interstate commerce during the 1973–74 biennium (reversing the position previously put forward some two years earlier in Opinion 699); and (4) relied on non-cost criteria to determine whether market factors (intrastate rates, alternative fuels, inflation, etc.) supported the cost-based rates.

While the new gas price in Opinion 770 was substantially above the previous rates set by the commission, the commission's reaction appeared to be too little too late. By early 1977, the newly elected administration became openly critical of the prevailing regulatory system. The Carter administration's proposed National Energy Plan stated that "producer claims that historic cost-based regulation is no longer appropriate for a premium fuel in short supply are fundamentally correct."

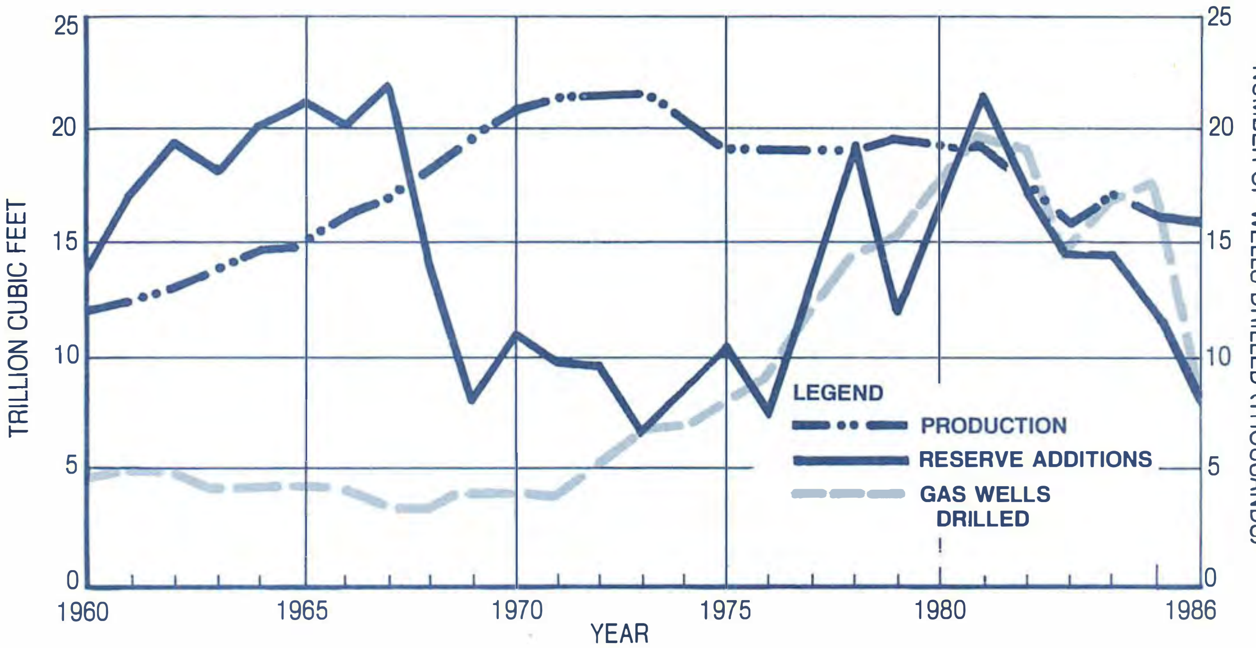

Figure 29. U.S. Natural Gas Production vs. Reserve Additions and Gas Wells Drilled (Lower 48 States).

When prices are not allowed to balance supply and demand, some other mechanism must be used to allocate the over-demanded commodity. With rigid FPC prices and limited supply, the pipelines began to curtail industrial customers in 1970. Although small at first, these curtailments grew rapidly, reaching 3.7 TCF by 1977. Curtailments meant higher fuel costs, plant closings, layoffs of workers, and eventual disruption of public services in the areas most affected. Sharp regional disparities developed as different pipeline systems had differing supply situations (such as access to offshore reserves, which were, by definition, dedicated to the interstate market).[14] During the unusually severe winter of 1976–77, interstate curtailments resulted in factory and school closings in several Midwestern, Northeastern, and Mid-Atlantic states.

The initial round of curtailments fell almost exclusively on "interruptible" customers, those industrial users whose contracts specified that their service could be temporarily interrupted during periods of peak demand. These customers were often electric utilities or large industrial users that maintained dual-fuel-burning capability in order to benefit from the "bargain rates" for interruptible service. This arrangement of interruptible service also benefited the pipeline companies by allowing them flexibility in managing seasonal load variations. However, in the face of more gas shortages, where expansive curtailments were no longer either temporary or limited to interruptible customers, the FPC was forced to intervene to devise some criteria for rationing the available supplies.

After initially approaching the problem on a case-by-case basis, the FPC in 1973 issued Order 643, an eight-step curtailment plan that gave residential and small commercial customers the highest priority classifications for receiving uninterrupted supplies. The pipelines tried to blunt the impact of the FPC order on their large industrial customers by contending that the commission had no authority to regulate direct industrial sales, which were not "sales for resale," and, therefore, not under the NGA pricing regulation. The pipelines' position was upheld in circuit court. However, the case was reversed by the Supreme Court in *FPC vs. Louisiana Power & Light Company* (1974), when it ruled that the FPC's curtailment jurisdiction was based on the transportation, rather than the pricing, provisions of the NGA. Had the circuit court's decision not been overturned, the large industrial users would not have been subject to the curtailments that occurred.

Congressional response to the gas shortages in the interstate market led to the enactment in January 1977 of the Emergency Natural Gas Act and the subsequent enactment in November 1978 of the Natural Gas Policy Act.

[14]Vietor, R. H. K., *Energy Policy in America Since 1945*. Cambridge University Press, 1984, p. 275.

Supplemental Sources

When demand for new gas began to outpace additions to domestic reserves, pipelines and suppliers looked to supplemental sources of gas to fill the demand gap. These included foreign sources, such as gas from Canada and Mexico, as well as liquefied natural gas (LNG) from North Africa, Indonesia, South America, Russia, Australia, Trinidad, and the Persian Gulf; and longer-term synthetic gas and coal gasification efforts.

Pipelines were able to absorb the high cost of supplemental sources by "rolling in" those costs with less expensive domestic gas. In general, LNG projects did not meet with much success because of both price and supply reliability problems. The original Border Gas Project from Mexico was scuttled because the price was too high relative to Canadian gas and other fuel costs, and the Alaskan Natural Gas Transportation System has not been built due to its huge capital requirement. Canadian gas remained a significant contributor, but the frequent export price adjustments caused serious consumer and policy concerns.

Of the synthetic gas projects, only the federally supported Great Plains Gasification Plant was constructed and commenced operation. When projected gas price increases envisioned at the time construction was initiated failed to materialize and the requested price guarantees and debt restructuring were denied, the operators terminated their participation in the project. The plant is currently owned and operated by the government.

The Political Debate—Competing Interests and Requisite Compromise

The political debate over the degree and form of federal intervention in natural gas markets evolved in three stages. From 1969 to 1973, Congress considered partial deregulation and structural reform of FPC procedures. From 1974 to 1977, momentum developed toward complete deregulation, but never fully took hold. Proposals were made for full deregulation as early as 1949; a deregulation bill passed Congress in 1956, but was vetoed by President Eisenhower. Finally, as part of the Carter energy plan, a compromise program emerged for commodity price regulation accompanied by gradual decontrol of new gas. Throughout the debate, the same issues predominated: distributive equity between producers and consumers, economic regionalism, the competitive versus monopolistic nature of energy markets, and the tensions between cost-based and commodity-based rate regulation.

Beginning in 1973, the energy crisis seemed to polarize the gas question between two fundamental alternatives: Congress could either deregulate the wellhead price of gas (or at least new gas) in the interstate market or else extend regulation to the intrastate markets, where market-based (commodity) pricing already prevailed. The growing gas demand and resulting depletion of interstate reserves militated for one or the other. The gas question also involved a basic disagreement between those who supported market-based prices, and those who contended that alleged monopolistic conditions required prices to be controlled by the government. Proponents of expanded regulations alleged that producers were "withholding" gas from the market to force removal of price controls. Investigations by the FPC, the Federal Trade Commission, and the Congress proved this theory to be factually unsupportable, but it continued to be put forward by advocates of price controls. As a result, most bills introduced between 1974 and 1977 were either deregulation measures or counterproposals for expanding the FPC's jurisdiction.

Throughout the area- and national-rate proceedings in the 1960s and 1970s, the commission relied on estimates of historical average costs, on either an historical (for "old" gas) or "current" basis (for "new" gas) to determine ceiling prices. The use of historical average cost estimates necessarily put the ceiling prices out of synch with actual costs. Because of the length of time required to develop a record, first through the hearing process and later through rulemaking procedures, the cost data were often out of date before the ceiling prices were ever decided upon. The averages were further distorted by the failure to include small producer data because of the administrative burden involved in collecting such data. The result of this approach was to render uneconomic the exploration and development of new gas supplies that cost more than the calculated "average." In addition, contracts with prices that were below the ceiling were enforced, while contracts with prices that were above the ceiling were reduced to the ceiling price level. Thus, while interstate ceiling prices increased substantially in the 1970s from the levels of the 1960s, they remained considerably below prices in the intrastate system, which were established and continually adjusted by market forces.

The Natural Gas Policy Act

After 18 months of deliberation and a contentious conference, Congress passed the

Natural Gas Policy Act in 1978 as part of the National Energy Plan. Under the Act, wellhead prices for certain categories of gas were to be decontrolled permanently in 1985 and in 1987, but other categories were to remain price controlled in perpetuity until produced and depleted. As a result, 40 to 50 percent of domestic gas remained under controls beyond the January 1, 1985, date and approximately 15 to 30 percent, absent further deregulation, will still remain under controls in 1990. In addition, in an attempt to resolve the disparity between the interstate and intrastate markets, the NGPA brought intrastate gas under federal regulation for the first time. The legislation also limited the FERC's authority to determine ceiling prices, except for certain powers to increase, but not decrease, the ceiling prices on pre-NGPA gas.

The NGPA's partial decontrol, phased over time, reflects judgments made in 1978 about U.S. energy, macroeconomic, and social policy. The Act was based on the premise that a soundly crafted price structure would concurrently stimulate domestic gas production and yet avoid unwanted consumer and macroeconomic impacts associated with generally higher prices.[15] However, the projected price structure chosen was based on then-current forecasts through 1985, which proved to be inaccurate. The NGPA did not provide a mechanism to permit the FERC to modify the ceiling prices when actual oil prices did not match the forecasted level.

The NGPA provided for:

- *Price Ceilings.* The NGPA set a series of maximum lawful prices for various categories of natural gas, including gas sold in both the interstate and intrastate markets. This eliminated the regulatory distinction that had previously existed between the two markets, with interstate rates set on the federal level and intrastate rates largely unregulated.
- *Deregulation of New Gas.* Price controls on new gas and certain intrastate gas were lifted as of January 1, 1985. Certain high cost gas was deregulated approximately one year after the NGPA's enactment. Gas from certain new onshore wells will be deregulated in July 1987. Old gas and some new gas from old leases will remain under price controls indefinitely.
- *Incremental Pricing.* The purpose of this provision was to protect residential consumers by first passing through some portion of increased gas prices to industrial users. It also was intended to discipline pipelines bidding for new gas. The concept never worked as planned and instead resulted in tying certain industrial gas prices to oil prices.

Despite unsuccessful attempts in Congress to modify the NGPA deregulation schedule, partial decontrol of natural gas was in fact accomplished on January 1, 1985, as scheduled. As a result, approximately half of the nation's gas supplies are free of controls today.

The Fuel Use Act

The Powerplant and Industrial Fuel Use Act was also enacted in 1978 as part of the National Energy Plan. It is important to remember that the Act was devised in reaction to the shortages and curtailments of the mid-1970s and predicated on the belief that the United States was running out of gas.

The Powerplant and Industrial Fuel Use Act prohibits the use of oil and gas as a primary fuel in any newly constructed utility power generation facility or in new industrial boilers with a fuel heat input rate of over 100 million British thermal units (BTU) per hour (unless exemptions are granted by the Department of Energy). The Act also limits the use of natural gas in existing powerplants to the proportion of total fuel used during 1974–76, and prohibits fuel switching from oil to gas.

The Post-NGPA Environment and Formation of the Gas Bubble

In reaction to higher oil prices and in anticipation of the removal of price controls, domestic oil and gas producers responded with record drilling in 1980 and 1981. For the first time in over a decade, reserve additions in 1981 exceeded annual consumption. Management of curtailments gave way to management of a surplus of deliverability. Market demand for natural gas fell as higher priced new gas supplies found their way into pipelines, and as fuel efficiency and conservation took hold on a national basis in reaction to the price increases arising from Opinion 770 and the NGPA. After 1981, this excess supply was compounded by decreases in the price of oil. As a consequence, reserve additions again began to fall as the "incentive" prices authorized by the NGPA became uncollectible in the marketplace, and revenues realized by producers declined.

It is interesting to note that in terms of its impact on increasing domestic supplies of

[15]U.S. Congress, *Natural Gas Policy Act Amendments of 1983.* Senate Report 98-205 (98th Cong., 1st Sess.), July 29, 1983, p. 10.

natural gas, the NGPA—like Opinions 770 and 770A—had precisely the desired effect. Through the use of incentive and market pricing and accompanied by rising oil prices, it stimulated new drilling activity and resulted in new gas production, which was previously thought to be limited. Two principal shortcomings were its lack of foresight with respect to demand elasticities for oil and gas and the pegging of gas prices to a fixed projection of rising oil prices.

Special Marketing Programs

In an attempt to address the problems associated with the gas bubble and maintain existing sales, the FERC authorized the use of special marketing programs (SMPs) in 1983. They were the first of a series of gas transportation programs that allowed lower priced spot market gas to be sold directly to distributors and industrial end-users rather than the traditional scheme in which the pipelines first bought and then resold the gas. SMPs were designed to regain lost direct and indirect customers of pipelines that were threatening to switch to an alternative fuel. Since most of the customers who can switch fuels are industrial users, SMPs were aimed primarily at them. On May 10, 1985, the District of Columbia court of appeals decided *Maryland People's Counsel vs. FERC* and found SMPs and certain other transportation programs flawed because they discriminated against local distribution companies and captive customers.

FERC Order 380

As a means of giving interstate pipeline customers greater flexibility in choosing between competing suppliers, the FERC implemented Order 380 in August 1984. The order removed gas costs from pipeline minimum bills. The effect was to greatly reduce the minimum costs of not purchasing gas from a pipeline supplier. For example, in 1984 this amounted to relieving customers of $2.75 per MCF of their $3 per MCF purchase obligation, leaving just a 25¢ per MCF obligation. No concomitant relief was given to pipelines on their contractual take-or-pay obligations to producers. The FERC argued lack of jurisdiction to modify gas purchase contracts, as contrasted to pipeline sales contracts.

FERC Order 436

In October 1985, the FERC issued Order 436 in an attempt to revamp the regulation of gas pipeline operations. The transportation program outlined in the order requires nondiscriminatory access to a pipeline's carriage service, and volumetric, downwardly flexible cost-of-service rates for firm-service and interruptible-service transportation.

Although the FERC had previously adopted programs aimed at allowing pipelines to transport gas for others (so-called "contract carriage") under certain circumstances, Order 436 was designed to allow broad, simplified, self-implementation of such programs. The FERC action followed inconclusive congressional consideration of mandatory contract carriage legislation. It also resulted from a belief by the commission that, in times of surplus, end-users and local distributors should be able to receive the benefits of low cost supplies. The commission also believed that, in the interest of competition, producers similarly should be able to sell surplus low cost gas supplies to customers other than their traditional pipeline purchasers.

FERC Order 451

Shortly after issuing Order 436, the FERC began consideration of a rule proposed by DOE to fundamentally restructure the "old" gas pricing system. The DOE proposal would have eliminated vintage pricing and replaced the various ceiling prices with a single ceiling price—the ceiling price for old gas brought into production after 1974.

In May 1986, the FERC issued Order 451, modifying the DOE proposal. This rulemaking would eliminate the large number of vintages of old gas by establishing a single ceiling price for gas dedicated to interstate commerce prior to enactment of the NGPA and still-regulated categories of gas sold under rollover contracts. The rule also establishes procedures for renegotiations of contracts and allows pipelines with multi-vintage contracts to nominate high cost gas for renegotiation when a producer nominates lower cost old gas under the same or other existing supply contracts between the parties.

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Chapter Three

Impact of Historical Price Shocks

INTRODUCTION

The year 1973 was a major watershed for the U.S. economy, dividing the high growth period of the 1960s from the stagflation of the 1970s and early 1980s. Table 8 provides a few highlights. For example, more than twice as many people were out of work, on average, after 1973 as before. The sharp drop in real GNP growth per employee highlights the sharp productivity decline after 1973. Without the sharp rise in female labor force participation in the 1970s and the entry of baby boomers into the labor force, the decline in real GNP growth would have been even more severe than it was. Moreover, the fact that real consumption growth was one-third lower after 1973 than before takes on much greater significance considering that the post-war baby boomers were coming of age in the 1970s. Consumption growth should have increased, not decreased. Similarly, despite the demographics, car sales and housing starts did not grow sharply between the two periods.

TABLE 8

U.S. ECONOMY
BEFORE AND AFTER 1973

Indicator	Average Annual Growth Rates (%) 1960–1973	1973–1985
Real GNP	3.9	2.3
Real Consumption	4.1	2.7
Real Investment	5.5	1.8
Industrial Production	5.2	2.3
Consumer Price Index	2.3	7.6
Employment	2.0	1.9
GNP per Employee	1.9	0.3

Indicator	Annual Averages 1960–1973	1974–1985
Treasury Bill Rate (%)	4.4	8.6
AAA Corporate Rate (%)	5.8	10.7
Unemployment Rate (%)	4.9	7.5
Unemployed Workers (millions)	3.8	7.8
Trade Balance (billion dollars)	3.3	-39.4
Federal Deficit (billion dollars)	5.5	86.8

The year 1973 represented the same watershed for the rest of the industrialized world as well. Real GNP growth in the countries of the Organization for Economic Cooperation and Development (OECD), excluding the United States, averaged 5.6 percent per year from 1960 to 1973. From 1973 to 1985, the average was only 2.4 percent per year. Data for selected major industrial countries are shown in Table 9.

The slowdown in real GNP or GDP (gross domestic product) growth after 1973 was less pronounced in the United States than in other major industrial countries. However, as noted above, the slowing of growth in the United States was limited by the great expansion of the labor force.

What happened in 1973? Many things happened: Vietnam war spending was winding down; wage and price controls had been in effect since mid-1971; capacity was being strained in

TABLE 9

WORLD ECONOMY
BEFORE AND AFTER 1973

Country and Indicator	Average Annual Growth Rates (%) 1960–1973	1973–1985
Canada		
Real GNP	5.6	2.6
Real GNP per Capita	3.9	1.4
France		
Real GDP	5.6	2.1
Real GDP per Capita	4.9	1.2
Germany		
Real GNP	4.4	1.9
Real GNP per Capita	3.5	2.0
Italy		
Real GDP	4.7	2.8
Real GDP per Capita	4.0	2.4
Japan		
Real GNP	10.4	4.0
Real GNP per Capita	9.7	3.1
United Kingdom		
Real GDP	3.2	1.3
Real GDP per Capita	2.7	1.2
United States		
Real GNP	3.9	2.3
GNP per Capita	2.7	1.2

many industries; monetary policy turned to fighting inflation; and the Nixon administration was preoccupied with Watergate.

The most important event, however, was the Arab oil embargo announced in October 1973. This event was both dramatic and unprecedented. The newspapers of the day expressed early incredulity, which rapidly turned to great uncertainty as to the implications for the U.S. economy. The effect of the embargo and accompanying production cutbacks on oil prices was dramatic. From the third quarter of 1973 to the third quarter of 1975, average OPEC oil prices rose by over 300 percent, from about $2.60 per barrel to about $10.50 per barrel.

Before the impacts of the Arab oil embargo and the associated oil price shock were fully understood or even fully felt, world oil markets were subjected to a second major shock, again the result of political developments in the Middle East. Work stoppages in the oil fields of Iran, part of the revolution that ultimately drove the Shah from Iran in January 1979, caused a cessation of oil exports from Iran in December 1978. The disruption of Iranian oil production and exports and the reaction in world oil markets triggered another sharp rise in oil prices.

From the first quarter of 1979 to the first quarter of 1980, average OPEC oil prices increased by 153 percent, from about $14 per barrel to over $35 per barrel. While the percentage change had been greater in the previous price shock, the absolute change was far greater during the 1979–80 period, both in current and constant (inflation-adjusted) dollars.

IMPACTS OF 1973 AND 1979 OIL SHOCKS

The fourth quarter of 1973 and the first quarter of 1979 represented somewhat similar economic environments in the United States: business cycles were peaking in both cases; the economy was operating near full employment; inflation was accelerating; and interest rates were at high levels. In both periods, most economic forecasts for the next year projected a mild recession.

In neither case did these forecasts recognize political developments in the Middle East, the dramatic impact of these events on oil prices, or the serious implications for the U.S. economy. As it happened, the U.S. economy suffered its two worst post-war recessions following the oil price shocks.

Beyond these similarities, the oil price shocks of 1973 and 1979 affected the U.S. economy to different degrees and with substantially different timing. Without trying to assign quantitative economic impacts to the oil price shocks themselves, a chronology of economic events is as follows.

The fourth quarter of 1973 coincided with a business cycle peak. By the trough of the recession in the first quarter of 1975, real GNP had declined by 4.3 percent. The unemployment rate rose from 4.8 percent to 8.9 percent by the second quarter of 1975, representing 3.9 million additional persons out of work. Industrial production had fallen 13.4 percent by the second quarter of 1975.

In 1979, on the other hand, real GNP continued to grow—by 1.6 percent—in the year following the oil price shock. There was a brief recession during 1980, due to credit controls and monetary tightening, but the full-blown recession did not start until the third quarter of 1981. This recession, the worst since the Great Depression, was more directly attributable to monetary policy than to the oil price shock. However, the tightening of monetary policy was in part a response to the inflationary impact of the price shock.

To suggest the magnitude of the impact on the U.S. economy of the oil shocks of the 1970s, it is useful to compare what actually occurred with typical forecasts made in late 1973 and early 1979. One major forecasting firm,[1] for example, expected real GNP to grow by 2.1 percent from the end of 1973 to the end of 1974 and by 15.3 percent through the end of 1976. The actual results were −2.4 percent and +3.4 percent, respectively. The level of consumer prices, at the same time, was expected to rise by 3.1 percent over the next year and by 12.0 percent over the next three years. The actual results were 12.1 percent and 29.3 percent, respectively.

Forecasts of a mild recession were common in early 1979. As of the first quarter of 1979, the same forecasting firm predicted that real GNP would grow by 0.4 percent over the next year and by 12.7 percent over three years. The actual results were 1.6 percent and −0.4 percent, respectively; the recession was delayed. The level of consumer prices was expected to rise by 6.8 percent over one year and by 19.5 percent over three years; the actual results were 14.3 percent and 36.8 percent, respectively. The point of these numbers is not to blame one particular firm for poor forecasting, but to show the macroeconomic consequences of the 1970s oil shocks.

Modeling and Analytical Approaches

Contemporaneous analysis of the economic implications of the oil embargo of 1973 and subsequent quadrupling of imported oil prices left much to be desired. The severity of the impact was generally underestimated. By September 27, 1974, the date of President Ford's conference on inflation, it was increasingly apparent that the economy was in a recession, and that the peak of the business cycle had occurred in the fourth quarter of 1973.

To be fair, there was no comparable period in the previous two decades of U.S. economic history from which to infer the impacts of the embargo and subsequent price increase. Some analytical approaches that were used for these inferences are discussed in Appendix C.

[1]The forecasts cited were from Chase Econometric Associates, Inc. However, the forecasts of the other major econometrics firms at that time—Data Resources, Inc., and Wharton Econometric Forecasting Associates, Inc.—were similar.

Results of Econometric Studies of the 1970s

Many econometric studies have been made of the first (1973) oil shock;[2] fewer have been made of the second shock. These studies, however, were based in 1972 dollars rather than the current yardstick, 1982 dollars.[3] For this study, the current version of Wharton Econometric Forecasting Associates' Quarterly Model, which is based on 1982 dollars, was used to estimate the impact of both oil price shocks.[4] The results are summarized in Tables 10 and 11 and presented in more detail in Appendix C, Tables C-2 and C-3.

The results indicate that the cumulative real effects grow strongly for about two years and level out after about three years. While the impact on economic growth rates fades, the level of economic activity remains permanently below the level that would have occurred had there been no shock. Similarly, the impact on the inflation rate fades over time, while the increase in the price level is permanent.

In summary, the cost of the 1973 oil shock appears to have been about 2.7 percent of real GNP by 1976, 1.4 million jobs, and an increase in the inflation rate of about 3 percentage points for one year and an average of about 1 percentage point for two additional years.

The simulated impact of the 1979 oil price shock is substantially greater than the 1973 shock. The 3.6 percent reduction in real GNP attributable to the oil price shock (through the fourth quarter of 1981) compares with actual growth of 1.2 percent over the same period. In other words, robust growth of 4.8 percent could have been expected had there been no shock.

[2]The results of one such study are presented in Appendix C, Table C-1.

[3]The National Income and Product Accounts are now reported in 1982 dollars instead of 1972 dollars. Because of the large growth of the oil industry between those dates, the domestic energy industries have a bigger weight in real GNP as currently reported than previously. Since the impact of higher oil prices in the 1970s was favorable to the domestic energy-producing industries, one would expect the effect of rebasing the National Income and Product Accounts to be to lower the real cost to the economy and (for similar weighting reasons) to raise the inflation impact. These expectations appear to be borne out in the Wharton simulations.

[4]The model was used to simulate the U.S. economy in the absence of the price shocks. Differences between the hypothetical no-shock case and what actually happened measure the impact of the price changes. The simulations were conducted without changing economic policies (except when endogenous to the model), exchange rates, or other exogenous variables. Holding economic policies constant is discussed in Appendix C.

TABLE 10

ECONOMIC IMPACT OF 1973 OIL PRICE SHOCK
ACTUAL VERSUS HYPOTHETICAL NO-SHOCK CASE
(Wharton Model Results)

	Third Quarter 1974	Third Quarter 1975	Third Quarter 1976
Real GNP (Billion 1982 Dollars)	-11.1	-58.9	-79.7
Percentage Change	-0.4	-2.1	-2.7
Inflation* (Percentage Points)	2.6	0.8	0.8
Unemployment Rate (Percentage)	0.2	1.0	1.4
Nonresidential Fixed Investment			
(Billion 1982 Dollars)	0.6	-10.0	-19.4
Percentage Change	0.2	-3.4	-6.1
Industrial Production (Percentage Change)	0.4	-3.5	-3.3
Trade Balance (Billion Dollars)	-8.9	-7.8	-8.7

*Percentage change in Consumer Price Index from one year earlier.

TABLE 11

ECONOMIC IMPACT OF 1979 OIL PRICE SHOCK
ACTUAL VERSUS HYPOTHETICAL NO-SHOCK CASE
(Wharton Model Results)

	Fourth Quarter 1979	Fourth Quarter 1980	Fourth Quarter 1981
Real GNP (Billion 1982 Dollars)	-27.4	-93.3	118.2
Percentage Change	-0.9	-2.8	-3.6
Inflation* (Percentage Points)	2.5	2.6	1.8
Unemployment Rate (Percentage)	0.3	1.3	1.9
Nonresidential Fixed Investment			
(Billion 1982 Dollars)	-2.9	-16.7	-27.7
Percentage Change	-0.7	-4.3	-6.6
Industrial Production (Percentage Change)	0.9	-3.8	-5.3
Trade Balance (Billion Dollars)	-10.6	-6.5	-1.3

*Percentage change in Consumer Price Index from one year earlier.

About 2 million jobs were lost, and the inflation rate was increased by nearly 3 percent for two years.

At least two factors contributed to greater severity of the 1979 shock compared with 1973: the relative sizes of the price increase and the share of energy imports in GNP. As noted above, the post-1979 price increases were greater in absolute magnitude than the post-1973 price increases, albeit lower in percentage terms. In 1973, before the Arab oil embargo, imports of petroleum and products amounted to roughly one-half of one percent of nominal GNP; by the time of the Iranian revolution, this ratio had quadrupled. Thus, one might have expected the 1979 event to have mattered more than the earlier one.

Moreover, domestic oil was subject to strict price controls throughout the first shock, lowering the average impact on individual and industrial users, while price controls were lifted completely during the first quarter of 1981. Thus, not only was the ratio of energy imports to GNP higher in 1979 than in 1973, but the effective price increase was much greater as well.

The relative impacts of the two price shocks of the 1970s are reflected in the shares of consumer budgets (disposable income) spent on motor fuels, home heat, electricity, and natural gas. The share rose from under 6 percent prior to the Arab oil embargo to nearly 7 percent later in the 1970s and nearly 8.5 percent after the second price shock. Recent declines in energy prices have lowered the share to the 6 to 7 percent range.

Sectoral and Regional Impacts

Some academic work has been done on the sectoral impacts of oil price shocks. The effect on energy-intensive industries is obviously adverse. However, the effect on virtually all sectors of manufacturing is unfavorable to some extent.

Most studies do not provide detailed impact estimates by industry. It is often difficult to separate oil price impacts from underlying long-term trends. Nonetheless, comparing what happened in different industries after the oil price shocks is informative. Not only are the results not necessarily what might have been expected, but they differ between the post-1973 and post-1979 periods. Tables 12 and 13 illustrate these points.

First, the downturn in industrial production appears to have been much faster and more severe after the 1973 price shock than after the 1979 shock. This result is partly due to the fact that November 1973 represented a business cycle peak, while the major downturn after the second shock did not start until July 1981. In any event, the peak-to-trough decline in the industrial production index was 14.8 percent in the 1973–75 recession and 11.4 percent in the 1981–82 case.

Second, overall domestic oil and gas exploration and production activity did not respond quickly to the rapid rise in world oil prices after the 1973 OPEC embargo. After 1979, on the other hand, domestic exploration and production grew sharply, notwithstanding the recession. More detailed industrial production indexes for the oil and gas extraction industries are in Appendix C, Table C-4. Part of the lack of rapid response in the earlier period was, no doubt, due to the long-term real price decline that had pervaded the petroleum industry in the 1950s and 1960s. This long-term decline contributed to expectations that the price increase was only temporary, and to a lack of capability by the oil industry to respond quickly. Part of the delayed response after 1973 was also due to price controls, which kept the price of most domestically produced oil and gas below world-market levels and thereby muted price signals to producers.

Third, the industries with the greatest output declines after the oil price increases were not the chemical and petroleum refining industries, which are directly downstream from petroleum production. Rather, production of transportation equipment, especially automobiles, declined sharply following both price shocks, as did construction-related activity. The declines in transportation equipment production reflected the increased cost of driving, the unavailability of fuel-efficient domestic cars, and the existence of temporary petroleum product shortages, as well as the effects of two recessions. Increasing competition from imported cars, particularly for small, fuel-efficient vehicles, was also an important part of the explanation.

The decline in construction-related activity (nonmetallic mineral mining; stone, clay, and glass; lumber and wood products) may be a result of the oil price jumps on inflation and, thus, on interest rates. High interest rates tend to reduce the demand for housing and nonresidential structures.

The last point is consistent with the behavior of the fabricated metals industry, which was adversely impacted by the oil price shocks of the 1970s. Many of the items produced by this industry are investment goods, and investment in general is hurt by rising

TABLE 12

POST-1973 INDUSTRIAL PRODUCTION INDEXES, SELECTED INDUSTRIES
(Percentage Changes from November 1973)

Industry	After One Year	After Two Years	After Three Years
All Industries	-5.5	-8.8	-0.8
Crude Oil and Natural Gas Extraction	-2.8	-4.5	-4.4
Nonmetallic Minerals Mining	-5.5	-13.1	-5.5
Textiles	-19.2	0.2	-7.7
Lumber and Wood Products	-21.2	-10.7	0.0
Paper	-9.4	-7.8	-4.2
Chemicals	-1.3	-3.2	6.5
Petroleum Refining	-3.1	-4.9	4.5
Stone, Clay, and Glass	-6.8	-11.3	-0.9
Primary Metals	-9.7	-25.4	-19.7
Fabricated Metal Products	-6.9	-16.3	-5.6
Transportation Equipment	-11.0	-14.4	-5.9

TABLE 13

POST-1979 INDUSTRIAL PRODUCTION INDEXES, SELECTED INDUSTRIES
(Percentage Changes from February 1979)

Industry	After One Year	After Two Years	After Three Years
All Industries	0.5	0.3	-3.5
Crude Oil and Natural Gas Extraction	7.2	10.1	16.1
Nonmetallic Minerals Mining	0.9	9.5	-4.8
Textiles	5.9	-0.2	-9.6
Lumber and Wood Products	-1.5	-7.1	-21.6
Paper	3.5	4.7	3.6
Chemicals	-1.3	1.3	-5.2
Petroleum Refining	0.9	-7.9	-19.7
Stone, Clay, and Glass	-0.5	-7.5	-15.5
Primary Metals	-9.5	-9.7	-31.5
Fabricated Metal Products	-3.8	-9.0	-16.2
Transportation Equipment	-8.7	-15.7	-23.8

interest rates. Also, machine tools—an important item in automobile manufacturing—are produced by this industry. The sharp declines in primary metals production are also related to these factors.

Cities such as Houston, Tulsa, and Denver grew rapidly with the growth of the oil industry, presumably at the expense of the rest of the country. Among the losing regions, the hardest hit were New England and the Middle Atlantic states. These areas have relatively cold climates and rely heavily on oil heat, which in 1980 was much more expensive than natural gas. In decreasing order of impact, other losing regions included western New York and the upper Midwest, with severe winters and heavy reliance on natural gas; Florida and nearby areas, with high electricity prices and usage; the lower Midwest, with its milder climate but heavy reliance on natural gas; and the upper Northwest, with its mild climate and cheap electricity.[5] One study, however, found that most economic activities were not sensitive on a regional basis to changing energy prices.[6]

The extent of differential regional responses to the oil price shocks can be seen in terms of the behavior of payroll employment in the United States—in the leading oil and gas importing states and in the leading oil and gas exporting states. As shown in Table 14, the latter states have performed better than the former since 1960, and the relative performance improved after 1973. Note that Alaska and California are shown separately as special cases: Alaska as a recent major oil producing state and California as both a major producing and importing state.

Macroeconomic Impact of Government Policy Responses

Few understood the macroeconomic consequences of the first oil shock. The Federal Reserve Board tightened monetary policy sharply in the spring and summer of 1974, which contributed to the timing and perhaps the severity of the 1973–75 recession.

The contemporary policy dilemma was well summarized by a quotation from the December 12, 1973, *Wall Street Journal*:

> Policymakers are puzzled because the Arab oil boycott threatens to produce an entirely new kind of business slump. "We've never had a shortage-induced recession before," says a White House official. "How do you handle it? If you just pump money into the economy, all you do is push up prices, because the goods aren't out there to buy. It's a dilemma we really haven't thought through."

In 1979, monetary policy was more accommodative, thereby delaying the recession. The degree of accommodation in 1979 may well have been greater than intended. There were credit controls in early 1980 that contributed to the brief recession of that year, but the Federal Reserve Board did not pursue a period of sustained tight monetary policy until late 1980. The sharp tightening of monetary policy, a response to the double-digit inflation caused by the oil shock and previous excessive monetary growth, triggered the worst U.S. recession of the post-war era.

TABLE 14

REGIONAL NONFARM PAYROLL EMPLOYMENT

	Percentage Growth in Nonfarm Payroll Employment 1960–1973	1973–1984
Oil and Gas Importers		
New York	15.4	6.0
Illinois	26.4	3.7
Pennsylvania	21.3	3.1
Ohio	30.7	3.3
Florida	110.4	51.5
New Jersey	36.8	21.0
Average	29.3	11.2
Oil and Gas Exporters		
Texas	75.5	55.4
Louisiana	50.2	35.8
Oklahoma	47.6	39.1
Kansas	36.3	25.8
New Mexico	46.4	45.4
Wyoming	30.7	57.7
Average	60.5	46.9
Alaska	96.5	102.7
California	55.7	38.5
United States	41.7	23.0

[5]See Proctor, Mary, "The Impact of Regional Political Issues on Energy Price Increases." *In* Landsberg, H. H., ed., *High Energy Costs: Assessing the Burden*. Washington, DC: Resources for the Future, 1982, p. 332.

[6]Miernyk, William, "The Differential Effects of Rising Energy Prices on Regional Income and Employment." *In* Landsberg, H. H., ed., *High Energy Costs: Assessing the Burden*. Washington, DC: Resources for the Future, 1982.

IMPACT OF RECENT PRICE DECLINES

Symmetry of Response

It is tempting to argue that, however costly the jumps in oil prices were in the 1970s, an equal benefit will occur in the 1980s from the collapse of oil prices. Econometric model simulations implicitly assume (and show) such symmetry.

"Symmetry" in this sense implies an equal and opposite reaction to oil price changes of equal and opposite magnitude. In historical context, moreover, symmetry has to do with reversibility: if the oil price shocks of the 1970s knocked the U.S. economy off a high growth path, can the reversal of the price shocks in the mid-1980s restore that higher path?

It seems more reasonable, however, to argue against full symmetry and to treat the model results as suggesting upper bounds for favorable impacts. Certainly some factors such as investments in energy conservation (e.g., additional home insulation, more efficient automobiles and gas furnaces, and fuller industrial use of waste materials for process heat) are largely irreversible. Other factors, such as perceptions of energy cheapness versus scarcity, may eventually be reversed, but the adjustment lags may be longer now than during the 1970s.

The principal argument for asymmetry in response to changing oil prices is that adjustment to changing economic conditions is never costless. Regardless of whether prices jump or collapse, time and effort are needed to recognize and adapt to the changing environment. Thus, even if the response of a frictionless economy were symmetric with respect to oil price changes, the existence of adjustment costs represents an effective lowering of output in both responses.

One source of irreversibility has to do with capital obsolescence. Plant and equipment that became uneconomic to operate following the two oil price shocks of the 1970s are not, in general, available for reuse in a world of lower oil prices. However, further new equipment spending for energy conservation (e.g., advanced jet aircraft) is being deferred.

The petroleum sector is far larger now than it was during the oil shocks of the 1970s. If one views the overall impact of oil price changes as being composed of "winning" and "losing" sectors, the "winners" were relatively small in the 1970s but the "losers" are more important in the 1980s. Thus, the growth of the petroleum sector, itself a result of the price shocks of the 1970s, creates an asymmetry in response.

A similar point concerns the growth of the service sector relative to manufacturing. Since services are typically less energy-intensive than manufacturing, the energy-to-GNP ratio has fallen.

The debt situation, domestic as well as international, is another source of asymmetry. High and rising oil prices do not lead to default on loans made for petroleum development; lower prices do, as has been seen in the southwestern United States.

The great international lending boom of the late 1970s and early 1980s was financed by the recycling of OPEC receipts. Countries such as Brazil absorbed large quantities of these funds, in particular to meet their high and rising bills for imported oil. The financial community was thus able to accommodate the vast inflow of deposits. What would happen in the event of equally massive withdrawals of OPEC funds? These financial asymmetries have become widely apparent in the wake of the general commodity price collapse of the early 1980s.

Another source of asymmetry has to do with consumer behavior. In 1973, and again in 1979, there were physical shortages of gasoline in certain key markets, as well as sharp price increases. There is no symmetry to the fear of continued shortage in a world of declining oil prices and ample fuel supplies. One might expect, then, that consumers would have cut back more sharply on purchases of cars (in particular) in the 1970s, for fear of not being able to drive, than they would increase such purchases in the 1980s.

Policy actions create additional asymmetries. Motor fuel taxes were not cut in the 1970s to compensate buyers for higher material prices. However, many states, and the federal government, have raised these taxes since 1982. Thus, consumers do not see symmetry in relationship between crude oil prices and retail product prices. Quantitative energy policies work in a somewhat similar way: the existence of Corporate Average Fuel Economy (CAFE) standards for automobile fuel efficiency means that, even if lower oil prices were to induce consumers to buy "gas guzzlers," the production of such cars would be severely limited.

A final source of asymmetry concerns the timing of responses. In the 1970s, consumption and investment spending were cut relatively quickly, while the increase in petroleum industry activity took more time to accomplish, particularly following 1973. Since the beginning of 1986, exploration and production investment has been cut more sharply than consumer spending has been increased. In essence, the downside effects of oil price changes are felt first regardless of whether prices rise or fall, while the upside effects are delayed.

An implication of the above points is that economic adjustment reflects both long- and short-term factors. Short-term factors are nearly all costly, while the longer-term ones are mixed. Thus, one might expect to see short-term negative impacts from oil price declines with more positive later results.

Macroeconomic Impacts

In general, a decline in oil prices directly benefits consumers and energy-intensive industries. By paying less for energy, real disposable income increases, with positive resultant effects on other broad-based macroeconomic variables, particularly consumption. As shown in Table 15, growth in personal consumption expenditures has accelerated significantly since the decline in oil prices.

TABLE 15

CONSUMPTION EXPENDITURES BEFORE AND AFTER THE OIL PRICE DECLINE (Billions of 1982 Dollars)

	Fourth Quarter 1984	Fourth Quarter 1985	Fourth Quarter 1986
Personal Consumption Expenditures	**2,271.7**	**2,351.7**	**2,450.4**
Durable Goods	326.8	347.0	381.3
Nondurable Goods	830.5	847.2	876.2
Services	1,114.4	1,157.5	1,187.6

Lower oil prices also reduce the oil import bill, improving the current account balance, reducing the transfer of wealth from the United States to oil exporting countries, and leaving more income to be spent on goods and services other than oil. The U.S. net oil import bill fell from $45 billion in 1985 to about $34 billion in 1986, despite a large increase in oil import volumes. If oil import volumes had remained constant, the oil import bill would have fallen to about $22 billion.

The economic benefits from lower oil prices take time to permeate the economy. Such benefits are initially overshadowed by the deep decline in the energy sector. While a rapid fall in oil prices has an immediate impact on the income of energy-producing, energy-service, and energy-related financial sectors, the positive effects of lower energy prices are more diffuse and slower to impact overall economic activity.

As discussed in the previous section, such positive economic effects are generally the reverse of those precipitated by the oil price shocks in the 1970s. However, the benefits are neither proportional nor symmetric to the earlier detriments—due to evolving political and structural changes in the economy.

Both the magnitude and the duration of the positive economic effects are dependent on the shape of the downward-price trajectory. It is uncertain whether oil prices will remain highly volatile, fluctuate within a narrow range, or remain relatively constant. The lower the oil price and the longer the duration of a low price, the greater the presumed macroeconomic benefits. Of course, fear of a rapid return to higher prices might limit these benefits. Consumers and producers of goods and services are not likely to change spending habits or make substantial investments if the price collapse is perceived to be short-lived. Eventually, however, a sustained period of lower oil prices can be expected to result in an increase in the overall level of economic activity.

Regional and Sectoral Effects

Lower oil prices have immediate negative regional and sectoral impacts. The depressive impact of the price collapse appears to have rapidly permeated oil-dependent regions and oil-related businesses. With the major oil producing states of Texas, Louisiana, Alaska, and Oklahoma accounting for roughly 10 percent of U.S. employment and retail sales, the deep and rapid oil industry decline significantly diminishes the positive macroeconomic benefits.

- Total investment in nonresidential structures (oil wells are treated as structures in the National Income and Product Accounts) fell at a 30 percent annual rate during the second quarter of 1986.
- Employment in the petroleum and petroleum-service sector has declined. These employment cuts create unemployment in area retail, wholesale, and other services dependent upon consumer spending.

- Reduced state and local revenues in oil-producing regions are leading to state and local government spending cuts and employee layoffs.
- Exports of oil industry equipment have fallen off, negatively impacting a portion of the U.S. trade balance.
- Regional financial institutions with large petroleum-investment portfolios and those with substantial exposure to oil-exporting-country loans are putting liquidity pressure on the U.S. financial system.

Several energy-related industries have directly benefited by the oil price collapse. Petrochemical producers, refineries, and metals, paper, transportation, and other petroleum-using industries are experiencing significantly lower factor costs.

- Higher profits are the immediate (if not long-term) result of lower raw material and lower "heating" costs. Initial gains in profitability have been secured as petroleum-related input costs have fallen faster than product prices.
- If expectations of lower energy prices are longer-term, many of these industries are likely to expand or to delay plant closings.
- New capital investment would likely (1) enhance the competitiveness of these industries, (2) increase industry productivity, and (3) raise their energy consumption.
- State and local governments in oil consuming regions will benefit from increased tax revenues as well as reduced spending for transfer payments.

The initial impact on the total U.S. economy has balanced out as shown in the selected data on industrial impacts that are presented in Table 16.

Selected Studies of Impact of Lower Prices

Most studies of the macroeconomic impact of lower oil prices are based on simulations of existing econometric models. These models were estimated with data from a decade of rising oil prices, hence the simulations represent nonhistorical experience. In general, the model results are symmetric with the price increase results, although, for reasons discussed earlier, symmetry is not likely to occur in the real world.

A Stanford Energy Modeling Forum study (EMF7) looked at the impact of a 20 percent decrease in oil prices on the U.S. economy from 1982 levels.[7] Fourteen models were simulated, and the results were surprisingly similar across models. Virtually all adjustment occurred within two years, with the economy basically resuming its prior growth trends thereafter.

Real GNP, in the median case, was 1.2 percent higher in the second year, abating to 1.0 percent higher after four years. The price level was 0.9 percent lower in the third and fourth years. The unemployment rate was 0.5 percentage points lower in the second year (more than a half-million workers) and 0.4 percentage points lower in the fourth year. As discussed in the section on symmetry of response, however, these results should be interpreted as upper bounds for what one might expect.

The EMF7 results were based on 1972 dollars. As argued above, however, the shift to 1982 dollars is theoretically important, and one might expect more of a price response and less of a real output and employment response. Accordingly, several simulations were run with current versions of macroeconometric models.

Macroeconomic Performance Under NPC Price Trends

The two price cases used in the NPC survey (explained in Chapter Five) were run through the Data Resources, Inc. (DRI) model to evaluate impacts through the year 2000. Shorter-term impacts were investigated with the Wharton PC Mark 8 model and Washington University Macro Model. The results are summarized in Tables 17 and 18. More complete results are presented in Appendix C, Tables C-5, C-6, and C-7.

The Wharton model was simulated for the first quarter of 1986 through the first quarter of 1989; the Washington University model from the second quarter of 1986 through the fourth quarter of 1988. The 4 percent and 5 percent real appreciation of the two price scenarios was implemented only approximately for these model simulations, using whatever the underlying inflation rate was in the starting simulation. The minor variation from the strict NPC scenario definition results from the feedback of oil prices on the GNP deflator.

There is a relatively wide range of results. The DRI model, for example, shows the three-year real GNP differential impact reaching just under 1 percent; in the Wharton model, the

[7]Hickman, Bert G., and Huntington, H. G., "Macroeconomic Impact of Energy Shock : An Overview." Working Paper EMF 7.2, Energy Modeling Forum, Stanford University, Palo Alto, CA, 1984, pp. 41 ff.

TABLE 16

RECENT ECONOMIC INDICATORS

Unemployment (%)*	November 1985	November 1986
United States	6.7	6.6
Alaska	9.5	11.0
Louisiana	11.3	13.4
Oklahoma	7.1	7.6
Texas	6.5	8.8
New Jersey	5.6	4.1
New York	6.1	5.3
Ohio	9.0	7.3
Pennsylvania	7.6	6.0

*Not seasonally adjusted.
Source: U.S. Department of Labor, Bureau of Labor Statistics.

PERCENTAGE CHANGES FROM PREVIOUS YEAR

Industrial Production	December 1985	December 1986
Total	2.4	0.8
Oil and Gas Extraction	-4.7	-15.0
Petroleum Refining	5.1	2.7

Source: Board of Governors, Federal Reserve System.

Inflation (Consumer Prices)	December 1985	December 1986
All Items, All Urban Consumers	3.7	1.1
Household Fuels	0.7	-9.4
Fuel Oil	5.5	-33.4
Utility (Piped) Gas	-4.6	-5.8
Gasoline	3.0	-30.6

Source: U.S. Department of Labor, Bureau of Labor Statistics.

New Plant and Equipment Spending	Actual 1985	Planned 1986
All Industries	9.2	-1.7
Mining	-5.9	-29.2
Petroleum (Manufacturing)	4.6	-30.1

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

TABLE 17

U.S. ECONOMY UNDER LOWER AND UPPER PRICE TRENDS

	DRI Lower	DRI Upper
Average Annual Growth Rates, 1985–2000 (Percent)		
Real GNP	2.6	2.5
Consumer Price Index	4.5	5.0
Real Fixed Nonresidential Investment	3.4	3.3
Industrial Production	2.8	2.5
Average, 1986–2000		
Unemployment Rate (Percent)	6.7	6.7
Net Exports of Goods and Services (Billion Dollars)	-15.4	-42.5
Federal Budget Deficit (Billion Dollars)	120.1	140.5
Automobile Sales (Million Units)	11.7	11.7
Housing Starts (Million Units)	1.7	1.7

maximum difference of 1.5 percent is reached in six quarters before settling at 1 percent, while the Washington University model shows continued widening through the end of 1988, albeit only to the 1 percent range. As argued above, these results should be interpreted as representing upper bounds for the favorable impacts of lower oil prices on real output, particularly in the short run.

Because the DRI model generates business cycles and because changes in oil prices affect the timing of these cycles, it is misleading to compare specific years under the two simulated scenarios. Doing so could result in comparing a business cycle peak to a business cycle trough. It is best to infer from the DRI model results, detailed in Appendix C, Tables C-6 and C-7, that the long-run real GNP difference between the two price scenarios is approximately one-half of one percent.

The unemployment rate results mirror the real GNP impacts. The DRI model shows a maximum difference of about 0.3 percentage points (slightly more than 300,000 jobs), while the Wharton model shows twice the effect and the Washington University model shows a maximum of 0.5 percentage points (slightly more than 500,000 jobs) in the fourth quarter of 1988.

The inflation impacts are quite similar in the models. There is initially a significant differential in the inflation rates between the two price trends. Later, the difference settles into the 0.2 percentage point range. This persistent difference reflects the feedback from oil price paths to overall inflation.

The econometric model simulations suggest that differences in long-run economic growth rates under the two NPC price trends would be relatively small. This is consistent with the oil-price-to-GNP relationships in the responses to the NPC Oil & Gas Outlook Survey. The economic impacts of higher oil prices are more severe in the case of a sudden price shock than in the case of a higher, but gradually rising, long-term price trend.

TABLE 18

U.S. ECONOMY UNDER LOWER AND UPPER PRICE TRENDS

	Wharton		Washington University	
	Lower	Upper	Lower	Upper
Average Annual Growth Rates, 1985: 4 Qtr. to 1988: 4 Qtr. (Percent)				
Real GNP	3.4	3.1	3.0	2.7
Consumer Price Index	2.8	3.6	2.4	2.8
Average, 1986–1988				
Unemployment Rate (Percent)	6.3	6.8	6.9	7.1
Automobile Sales (Million Units)	10.4	10.4	7.5*	7.3*

*Domestic only.

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Section II

Factors Affecting U.S. Oil & Gas Outlook

Chapter Four

Introduction—Factors Affecting Oil & Gas Outlook

The Secretary of Energy requested that the NPC examine the factors affecting the nation's future supply of and demand for oil and gas. The NPC's approach to fulfilling this request has been first to identify the various factors, then to analyze how each of these factors operates to increase or decrease supply and demand. Where feasible, the effects of each factor on supply and demand were quantified.

The use of a factor approach for analyzing future consumption and supply of oil and gas reflected the NPC's concern about correctly projecting future supply and demand. Rather than forecasting specific supply/demand balances, the NPC felt that the analysis would be better served by examining the potential effects of the various factors. While not providing a definitive forecast of the future, this approach provides analyses and insights from which policymakers can draw guidance as the future unfolds.

For analytical purposes, the factors were organized into four general groupings: economic factors, physical factors, institutional factors, and international factors.

The prime economic factor affecting both supply and demand is price. Other economic factors affecting supply and demand include the levels of U.S. income and industrial production, demographics, financial factors, energy conservation incentives, industrial structural changes, and lifestyle changes. Other significant economic factors affecting demand are the availability and price of alternative fuels, near-term switchability, and long-term capital decisions associated with utilization of alternative fuels.

One key physical factor is the U.S. oil and gas resource base—the proved reserves and the amount of undiscovered oil and gas. Another key physical factor is the petroleum industry infrastructure that provides the capability to drill the exploratory and development wells to find and produce new reserves, and the surface facilities to produce the oil and gas and deliver it to market. Another physical factor affecting oil and gas supply and demand is technology advances.

Institutional factors include environmental policies and regulations affecting access to petroleum resources, both onshore and offshore, those affecting production and distribution, and those affecting consumption of petroleum products and alternative fuels. Institutional factors also include other government policies affecting supply and demand—government leasing policies, price controls, allocations, royalties, taxes, import fees and quotas, gas pipeline regulations, subsidization of alternative fuels, trade policies, conservation initiatives, fuel use restrictions, state prorationing, and international and diplomatic policies.

The international factors are, of course, the ones that U.S. policies can influence or affect the least. But they must be recognized as having significant capability to affect U.S. petroleum supply. Their potential effects have to be integrated into the analysis of the factors that can be influenced by U.S. policies and actions. The fact that oil is a fungible product must also be recognized—OPEC oil, U.S. oil, Mexican oil, North Sea oil, etc., except for quality differences reflected in price, are readily substitutable for each other. Oil is easily transported and is traded on a worldwide basis. Probably the most important international factor is the behavior of OPEC and its individual members in the world oil market. Other international factors analyzed include non-OPEC supply, world oil demand, and world politics.

CHAPTER FIVE

ECONOMIC FACTORS: SUPPLY/DEMAND RESPONSES TO MAJOR OIL PRICE CHANGES

INTRODUCTION

This chapter primarily addresses the effects of oil and gas prices on oil and gas supply and demand. A questionnaire prepared by the NPC requested detailed oil, gas, and energy outlooks for the United States and the non-communist world under two oil price scenarios provided by DOE. The upper price trend started at a composite U.S. refiner acquisition cost of crude oil of $18 per barrel in 1986, rising at 5 percent per year in real terms to $36 per barrel in the year 2000. The lower price trend starts at $12 per barrel in 1986, rising at 4 percent per year in real terms to $21 per barrel in 2000.

Fifty-two questionnaires were sent to selected oil and gas companies, gas and electric utility companies, agencies and associations, a major manufacturer, consulting companies, and financial institutions. Thirty-three responses were received, of which twenty-eight were in a usable form.

Another survey, conducted by the Independent Petroleum Association of America and the Society of Independent Professional Earth Scientists of their memberships, sought to determine how the recent oil price decline has impacted the near-term outlook for drilling. Respondents were asked to estimate their participation in wells from 1986 to 1990 based on three price scenarios for oil and gas: $13 per barrel and $1.30 per MCF, respectively; $20 per barrel and $2.40 per MCF; and $27 per barrel and $3.50 per MCF. The low and middle prices approximate the lower and upper price trends of the NPC Oil & Gas Outlook Survey. The results of these surveys are included in this chapter along with a discussion of how crude oil and natural gas prices have affected the supply of and the demand for these energy forms in the past.

Under the assumed price trends, the response to the NPC Oil & Gas Outlook Survey indicated production will continue to decline. The survey shows that the average annual replacement of reserves will decline. While the United States is already a net importer of both oil and natural gas, the level of dependence on oil imports will grow dramatically over the next 15 years, from 4.2 MMB/D in 1985 to 9.1 MMB/D under the survey's upper price trend and to 13.6 MMB/D under the lower price trend.

The survey results indicate that lower oil prices stimulate the economy and increase energy and oil consumption. In the upper price trend, total energy and oil consumption increase at average rates of 1.1 percent and 0.7 percent per year, respectively, from 1985 to 2000. In the lower price trend, the growth rates are 1.3 and 1.6 percent, respectively.

Most of the oil consumption increase occurs in the transportation, industrial, and electric utility sectors. With lower prices, there is less incentive to conserve energy. At low energy and oil prices, individual consumers, commercial establishments, and industries are all less inclined to invest in the most energy-efficient appliances, automobiles, and machinery.

This does not signal a return to the conditions of the 1950s and 1960s, when energy consumption and the economy grew at the same rate. Rather, it indicates a slowing in the rate of energy efficiency gains. The lagged response of capital stock replacement to the price shocks of the 1970s continues to be felt. Even if low prices continue for some years and future efficiency improvements are deferred, the energy-to-GNP ratio will decline, but at a somewhat slower rate.

Interfuel substitution also becomes a factor at low oil prices. Manufacturing plants and electric utilities must switch from gas to oil in the lower price trend due to shortfalls in gas supply at low prices. There is also the potential for oil to displace some coal in this scenario.

CRUDE OIL AND NATURAL GAS PRICE HISTORY

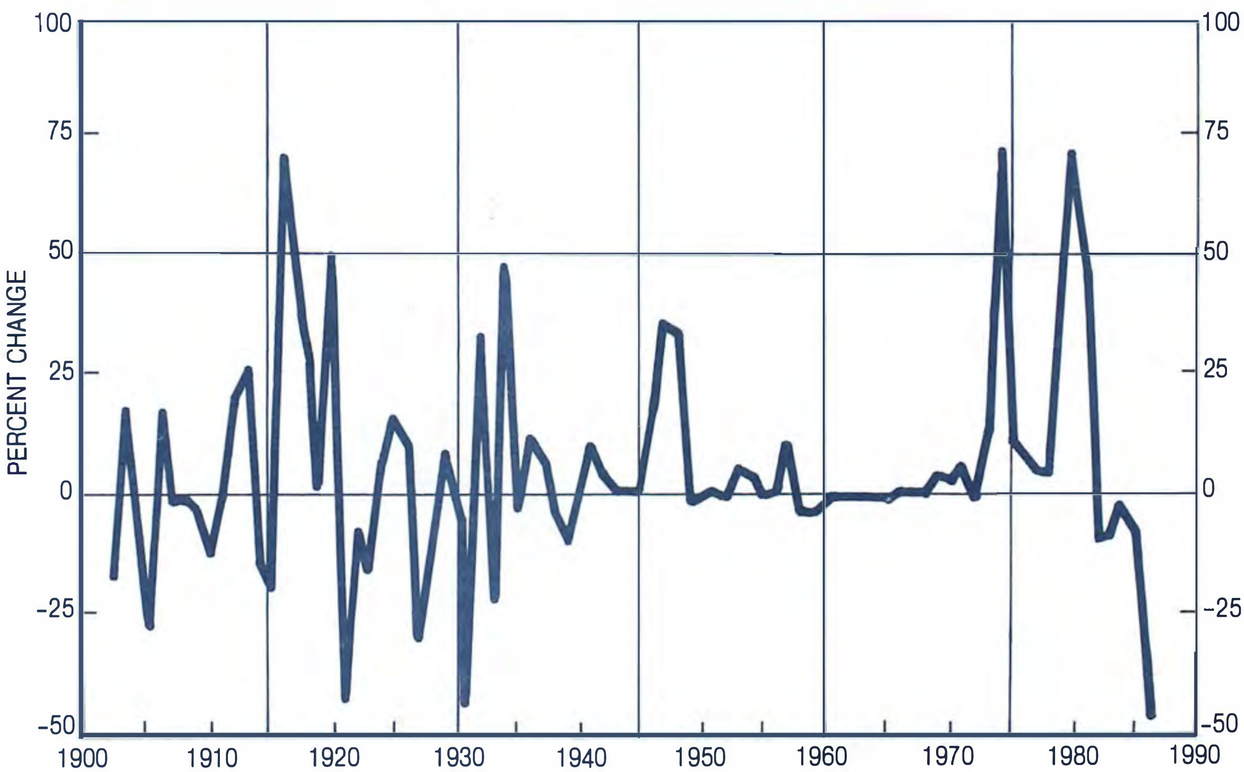
Crude Oil Prices in Retrospect

Since its inception in the mid-1800s, the U.S. oil industry has been through many periods of price volatility. As shown in Figure 30, the annual percentage changes in oil prices between 1900 and the early 1930s rival those the world has been through since the early 1970s.

In the years before 1933, prices were extremely volatile. A wave of price volatility swept through the industry after the Standard Oil Company (New Jersey), successor of the Standard Oil Trust, was ordered by a federal court in 1911 to divest most of its affiliated companies. The average nominal wellhead price in the United States increased from $0.61 per barrel in 1911 to $3.07 in 1920. By 1931, it had retreated to about $0.65 per barrel.

This extreme volatility in prices eventually led to prorationing, for purposes of conservation (prevention of waste) and protection of correlative rights, by the Oklahoma Corporation Commission in 1930 and the Texas Railroad Commission in 1933. The Texas law defined waste to include the production of crude oil in excess of transportation and market facilities or reasonable market demand. The Texas Railroad Commission and similar regulatory bodies in other major oil-producing states, and in conjunction with oil import quotas beginning in 1959, were able to maintain a relatively stable market until 1973. As shown in Figure 31, U.S. nominal wellhead prices rose gradually from $1 per barrel in 1934 to $3.89 per barrel in 1973—an average annual growth rate of 3.5 percent. However, oil prices in constant dollars remained relatively flat between 1934 and 1973 (see Figure 15 in the Report Summary). During those 40 years, the sharpest year-to-year price change never exceeded 10 percent, except immediately following World War II.

From 1934 to 1973, oil prices were also relatively stable outside the United States. Many giant fields (over 500 million barrels) were



SOURCE: *Salomon Brothers*

Figure 30. Percent Change in Annual Average Crude Oil Wellhead Prices (Nominal Dollars per Barrel).

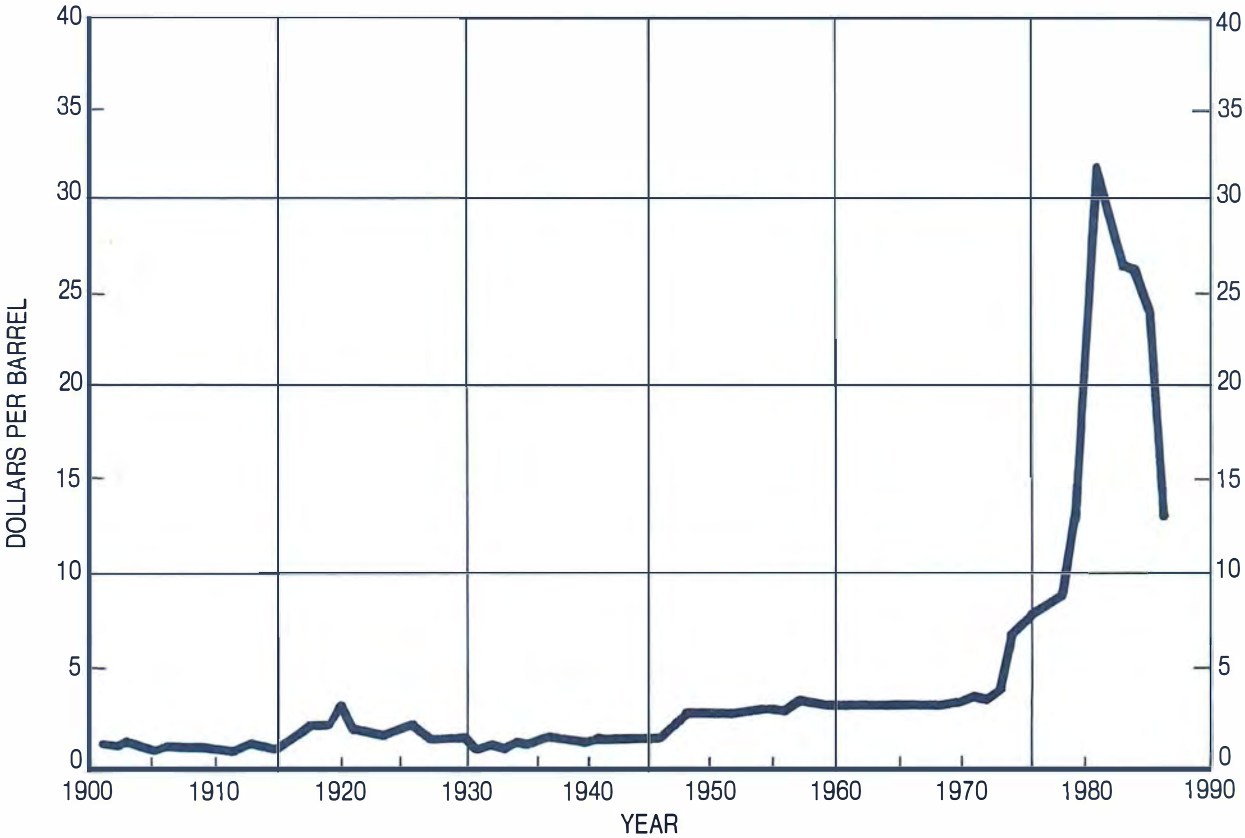


Figure 31. Annual Average U.S. Crude Oil Wellhead Prices (Nominal Dollars per Barrel).

discovered in the Middle East and North Africa during this period, providing adequate supplies to meet growing demand. Still, price volatility in the international market was often greater than that experienced in the United States. In the late 1950s, when oil prices were again under downward pressure, Venezuela and a number of major producing countries in the Middle East decided to coordinate their policies in order to prevent further price declines. Thus the Organization of Petroleum Exporting Countries was created in 1960.

OPEC's influence in world oil markets was minimal until the early 1970s, when the Tehran and Tripoli agreements and the Arab oil embargo marked a new watershed in the industry's history. The OPEC countries, first through negotiations with oil companies and then unilaterally, increased their posted oil prices from about $3 per barrel in 1973 to over $35 per barrel in 1981—an average annual increase of 36 percent. As discussed earlier, U.S. oil price controls held U.S. prices below world oil prices between 1973 and 1980.

The rapid price increases of the 1970s—particularly those in later years, which raised the price from about $13 per barrel in 1978 to over $35 per barrel in 1981—made a significant impact on the world oil industry in a number of ways. First, higher oil prices reduced economic growth and prompted conservation and substitution. These factors combined to cause a very sharp decline in non-communist world oil demand, which fell from a peak of 52 MMB/D in 1979 to about 46 MMB/D in 1985. Second, the high price provided an increased economic incentive to develop oil outside the OPEC countries. Thus, non-OPEC crude oil and condensate production increased rapidly—from about 15 MMB/D in 1973 to about 23 MMB/D in 1985. As a result of these two factors, a significant decline occurred in OPEC's production of crude oil—from over 31 MMB/D in 1977 to about 16 MMB/D in 1985. OPEC capacity by the end of 1985 was estimated to have been about 27 MMB/D. Thus, spare productive capacity in OPEC countries was about 11 MMB/D, primarily concentrated in the Middle East.

Acting on the premise that demand for oil would soon rebound and that the surge in non-OPEC production would plateau, OPEC, and particularly Saudi Arabia, initially reduced production to maintain oil prices. However, downward price pressure forced the organization to reduce its benchmark price from $34 per barrel in 1981 to $28 per barrel in 1985. Despite these price reductions, OPEC's share of the total market continued to decline.

In December 1985, OPEC decided to increase its market share. The world's oil markets could not absorb the increase in production and prices fell from about $27 per barrel in December 1985 to less than half that level by mid-year 1986. The price fell as low as $10 per barrel before stabilizing in the fall at about $15 per barrel. By year-end, following OPEC's decision to return to a fixed price system, the price had risen to about $18 per barrel.

The shift of the swing oil producer's role to Middle East OPEC has been a major factor affecting price instability since the mid-1970s. During the 1970s, when OPEC's capacity utilization level moved above 80 percent, its members were able to increase prices and maintain them at high levels. Subsequent to the second oil price shock, due to increases in non-OPEC energy supplies and the decline in world oil demand, OPEC's capacity utilization fell to such a low point that in late 1985 some members opted to regain their market share rather than hold the price at former levels.

The world has experienced short-term oil price instability within longer-term oil pricing cycles. A trend toward lower real prices, as occurred in the 1950s and 1960s, carries with it the seeds of its own destruction and can result in a sudden price spike. If oil prices remain low for a significant period, the demand for oil will grow and non-OPEC supplies will decline, increasing the reliance on OPEC, especially the Middle East countries—the incremental source of imported oil to the noncommunist world. Eventually, as OPEC excess productive capacity is reduced, even a relatively small supply disruption could send prices skyrocketing. Recent history has demonstrated that world oil supply and demand imbalances of as little as 5 percent can cause large increases or decreases in the price of oil. At the end of 1985, Saudi Arabia's production increase of only 2 MMB/D precipitated the present sharp oil price decline.

Factors Contributing to Oil Price Volatility

A number of factors contribute to oil price instability and volatility. First and foremost is the continuing effect of the international marketplace on oil prices. Its political, economic, financial, and psychological effects on oil prices contribute to the ongoing volatility. Second, demand responds very little to oil price changes in the short run. If prices increase, consumers can respond through conservation and/or substitution. However, these efforts are limited because time is required for technological innovations and capital stock turnover. Because of the limited responsiveness of oil demand to price, relatively small changes in oil supply can trigger large movements in prices. Demand also responds slowly when prices fall. Once new technology is embodied in the capital stock, the energy-efficient machinery and equipment are likely to remain in operation.

Third, supply responds to oil price changes in only a very limited way in the short run. Oil exploration, development, and production involve years of lead time. Thus, a sudden increase in oil prices—even a sharp one—can add very little to supply in the short term if no spare productive capacity is available. This enables producers to raise or maintain high prices when supply is tight. Conversely, a sudden decline in oil prices also has a minimal short-term impact on supply, since a very large portion of the cost of finding and producing oil occurs at the exploration and development stages. Once these costs have been committed, production is likely to continue as long as the wellhead price is above the operating cost. Thus, prices may have to fall substantially to force production to be shut in, even in economically marginal fields.

Fourth, because of seasonal variations in demand for oil and the industry's responsibility to supply a steady flow of products to the consumer, oil companies hold substantial inventories. In order to minimize the risk of huge financial losses or shortage of supply, the industry must react quickly to sudden changes in oil prices. A sudden increase in price usually results in an inventory accumulation by oil companies, distributors, and consumers, which in turn aggravates the situation. When sharp price declines are expected, they usually attempt to lower inventories to minimize loss. In so doing, they again may exacerbate the price change. In addition, oil prices may fluctuate due to changes in demand brought about by cyclical changes in the world economic activity.

Like other commodities, oil is subject to short-term volatility as well as to long-term cyclical fluctuations. Depending on their length and severity, these price variations not only affect the health of the oil industry, but also may cause costly dislocations in world and/or regional economies.

Coping with price instability is difficult in the capital-intensive oil and natural gas industry, with the long lead times required for investment. This price instability and the resulting uncertainty represent an added risk that raises the expected return needed to justify an investment.

Natural Gas Prices in Retrospect

Interstate wellhead natural gas prices have been regulated since 1954. Consequently, gas prices remained fairly stable until 1970, as shown in Figure 32. This price regulation, together with approximately $1 per MCF of pipeline transportation and industrial distribution charges, has held wellhead gas prices below the equivalent crude oil prices, as shown on Figure 33. The tradeoff for stable and artificially low gas prices has been an unreliable supply of gas in the interstate market, accentuated in the mid-1970s by severe supply curtailments. Factors affecting the development, use, and pricing of natural gas are discussed in Chapter Two.

The FPC initially attempted to regulate producer prices using a company by company approach; this proved impractical. Consequently, the FPC adopted the area-rate approach, resulting in the Permian Basin ceiling rate, which set rates based on finding and production costs. Rates for various other regions of the country were subsequently set.

The area-rate approach was used until the early 1970s, when the commission adopted a national-rate approach in response to an underlying trend of diminishing dedications of natural gas reserves to the interstate market. Not only were the uneconomically low interstate prices discouraging gas exploration, the non-regulated intrastate markets were increasingly bidding away new gas supplies from the interstate markets, as shown by the higher prices for new intrastate gas in Figure 32. The price inequity between the interstate and intrastate gas markets, together with the oil embargo of 1973, forced the FPC to raise prices for new interstate gas supplies from below $0.40 per MCF to levels as high as $1.42 per MCF for gas discovered after January 1, 1975.

In this period of rapidly rising oil prices, interstate gas prices remained artificially low, and the downward trend in new gas reserve additions and interstate dedications continued. Declining supplies meant that some demand was not being met, a problem that was exacerbated by unusually cold winters in 1976 and 1977. The result was severe curtailments of interstate gas pipeline supplies from 1973 to 1979. The response to these factors was the passage of the Natural Gas Policy Act in late

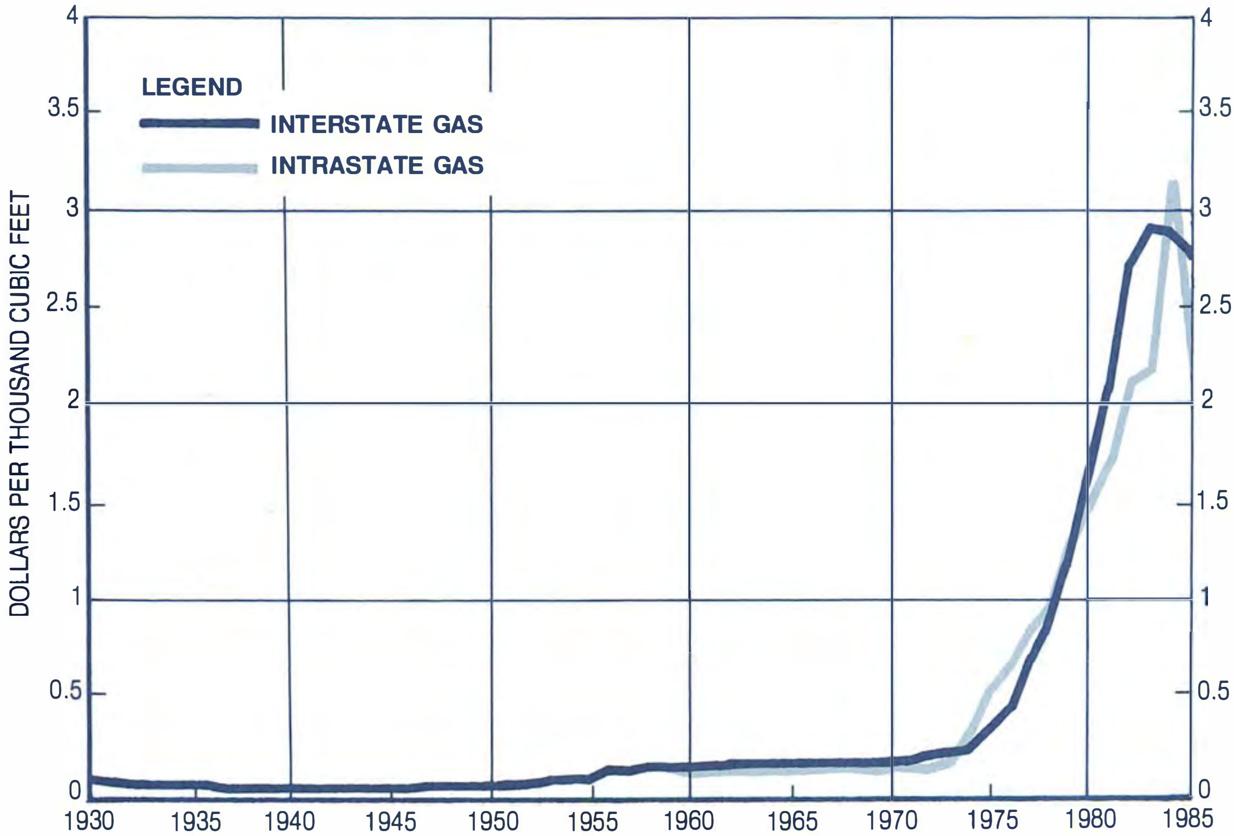


Figure 32. Annual Average Natural Gas Wellhead Prices (Nominal Dollars per Thousand Cubic Feet).

SOURCE: Prices are taken directly from or calculated from data in the *Natural Gas Monthly*, published by the Energy Information Administration of the Department of Energy.

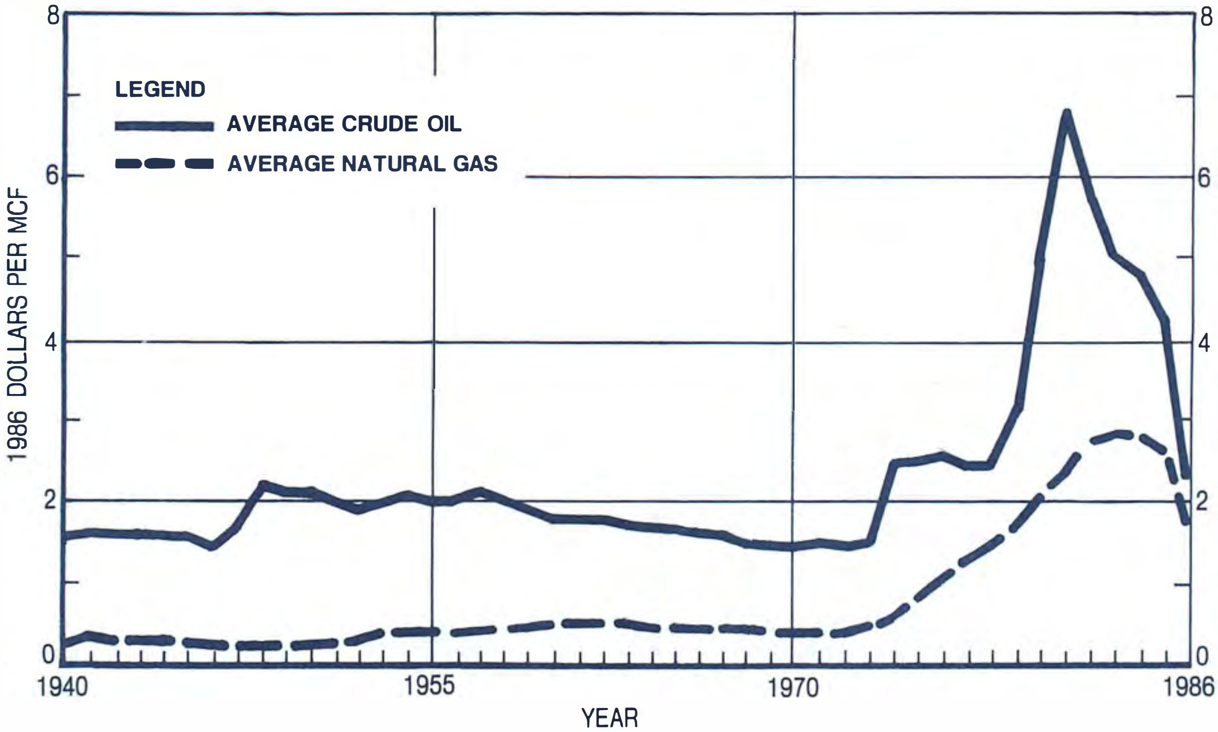


Figure 33. U.S. Natural Gas Wellhead Price vs. Equivalent Crude Oil Price (Constant Dollars per Thousand Cubic Feet).

1978. The NGPA established a schedule of ceiling prices for regulated gas corresponding to a classification system of multiple gas "vintages." Over 30 categories of gas were created, with differing prices, rates of escalation, dates—if any—for deregulation, plus additional non-price regulations. Regulated ceiling prices for most "new" gas (produced from wells drilled on or after February 19, 1977) were set such that they escalated monthly in real terms with the goal of reaching parity with the forecast equivalent oil price on January 1, 1985, the date when most new gas prices were scheduled to be decontrolled.

The result was a complex system of wellhead price controls and incentives that was designed to be a political tradeoff between allowing prices high enough to spur new production while giving consumers the benefit of low prices for gas that had already been discovered. The sending of incorrect pricing signals was inevitable in a system that provided for a broad range of prices at the wellhead and essentially one average market price on the consuming end for each pipeline.

For deep gas (below 15,000 feet), the only vintage that was deregulated in 1979, newly contracted prices in the $7 to $9 per MCF range were common. These high prices were possible because they applied to relatively small volumes of gas. When they were rolled in with large volumes of low priced regulated gas, the resulting average delivered price was still competitive with other pipeline supplies and fuel oil.

As gas prices rose, exploration for and production of high priced gas increased. From 1980, gas demand declined in response to price-induced conservation, two economic recessions, the shifting of the U.S. industrial structure away from gas-intensive industries, and fuel switching. Excess gas deliverability and declining demand for both oil and gas forced a decline in prices and heightened both interfuel competition and competition among gas suppliers (gas-to-gas competition).

The year 1983 was pivotal for the gas industry. The average wellhead price of interstate gas peaked at about $3 per MCF and has continued to fall since then. The price of residual fuel oil dropped to a level that put it in direct competition at the industrial burnertip with natural gas. To maintain market share in the fuel switchable industrial and power plant markets, the burnertip price of gas had to be competitive with the equivalent fuel oil price. By implication, the "netback" gas price at the wellhead had to be lower than the equivalent delivered price of oil by the amount of pipeline and local distribution company transportation charges.

Later in 1983, oil prices stabilized, but due to the excess deliverability of gas (the gas "bubble"), gas-to-gas competition caused gas prices to continue declining. The year marked the beginning of a major restructuring of the U.S. natural gas pipeline industry, a transition that is still unfolding.

The new competition for markets led to other problems that had not been anticipated by the industry. Historically, gas had been purchased and sold at the wellhead under long-term contracts that typically had provisions obligating the purchaser to take, or nevertheless pay for, a minimum amount of a producer's gas (take-or-pay provisions). In the years just prior to 1983, the contract price was frequently set at the highest price allowed by law. When rolled in with prices from older supply contracts, the resulting average price could still compete with fuel oil. When fuel oil prices began to decline in 1983 and gas sales began to be lost to fuel oil, pipelines at first attempted to minimize their take-or-pay obligations by maintaining high levels of purchases from the newer, higher priced take-or-pay contracts. As gas-to-gas competition intensified, pipelines had to increase takes of lower priced old gas in order to keep their rolled-in average prices at market-clearing levels. This, in turn, resulted in higher and higher volumes of high price take-or-pay gas that had to be paid for but not taken.

In April of 1983, FERC allowed pipelines and producers to initiate special marketing programs that temporarily released gas from dedication under long-term contracts. The programs allowed pipelines take-or-pay relief in exchange for providing producers with a means of selling their gas that was otherwise rendered unmarketable by the existing contracts.

To stimulate competition, FERC issued Order 380 in August 1984, which removed gas costs from pipeline "minimum bills" (the minimum amounts pipeline customers had to pay for gas service, regardless of the volume purchased). Many gas distributors in the Midwest and Northeast are supplied by two or more pipelines. Order 380 encouraged more competition in the natural gas end-use and distributor markets by effectively relieving pipeline customers of the long-term obligations to pay for the minimum contract quantities of gas from their suppliers. No concommitant relief was given to pipelines on their take-or-pay obligations to producers. However, some producers' take-or-pay contracts include limited make-up rights to pipeline purchasers.

On May 10, 1985, the District of Columbia Circuit Court of Appeals struck down special marketing programs. In response to the end of special marketing programs, FERC accelerated the movement to implement open access transportation in the industry by issuing Order 436 in October 1985. The order encouraged pipelines to voluntarily transport gas from any producer to any purchaser on a nondiscriminatory, first-come first-served basis, thus providing open access to pipeline transportation services and allowing producers and consumers to negotiate their own sales agreements, thereby stimulating competition. Consumers are allowed under the Order to completely phase out their contractual commitments to purchase gas from pipeline suppliers that elect to be nondiscriminatory transporters over a five-year period, while the pipelines' commitments and take-or-pay obligations with gas producers were left intact. The Interstate Natural Gas Association of America has estimated the pipeline industry's remaining take-or-pay liability to be $13.7 billion by the end of 1986. Some of the take-or-pay liability of the pipeline industry has been eliminated by negotiated settlements between pipelines and producers at less than the total liability.

Another recent FERC action is Order 451, which was designed to allow old gas prices to rise to the current market level. This order, issued in June 1986, permits with the buyer's concurrence the collection of a higher ceiling price for most vintages of old gas. Producers are allowed the right to renegotiate contracts for old gas with pipelines and seek a higher price, up to the new ceiling price. However, if a producer chooses to initiate contract renegotiations, the pipeline has the right to renegotiate all contracts with that producer that contain old gas, including mixed old gas and new higher priced gas contracts.

The combination of reduced gas demand, excess gas deliverability, and major regulatory changes are altering the complexion of the natural gas industry. While some industry analysts have labeled the regulatory changes as a move toward deregulation, increased competition is a more appropriate description. The industry continues to be tightly regulated with regard to pipeline operations and obligations to serve customers. Financial returns for pipelines will continue to be constrained, while the risks have increased significantly under the free-market ideology being advocated by FERC. The net result is a shifting of opportunities, risks, and roles among the producers, pipelines, distribution companies, independent gas marketers, and consumers.

SUPPLY RESPONSE TO PRICE CHANGES

Effect of Prices on Costs of Finding, Developing, and Producing Oil and Gas

Current and expected oil and gas prices determine exploration and development activity.

Figure 34 compares a standard measure of exploration and development activity, the Hughes rig count of active drilling rigs, to both the new oil price and the average U.S. oil and gas price in constant 1986 dollars. The basis for establishing the new oil price is discussed in Appendix D. It is the initial price that a producer of a newly completed oil well would receive during that year. The new oil price in Figure 34 is based on West Texas Sour crude oil, which sold at the industry average price prior to the commencement of a two-tier price system in 1973 and represented the same quality crude oil as the international benchmark crude oil, Saudi Light. The average oil and gas price fell only gradually from 1981 through 1985 as the previously discussed natural gas price increases under the NGPA of 1978 partially offset the decrease in oil price.

As shown on the chart, the Hughes rig count generally lagged the variations in the new oil price. This can be attributed to the time required to perceive a change in the future price environment, shortages of funds for investment due to oil and gas price controls, and constraints on the availability of drilling rigs.

The tremendous variation in rig count during the past 15 years has caused large variations in demand on the oil field service sectors, which has been reflected in the cost of oil field supplies and services. Table 19 shows the impact of these price variations on contract drilling rates and completed well costs. Costs and rates more than doubled between 1970 and the early 1980s. Subsequently, as activity declined, rates declined due to an extensive oversupply of drilling rigs on the market, and contract drilling rates have declined to levels that existed in the early 1970s. However, completed well costs have remained above 1970 levels. (Completed well costs represent the average cost to drill and complete oil wells, gas wells, and dry holes within the depth brackets reported in the Joint Association Survey of Drilling Costs for 1970 through 1985.)

The increase in contract drilling rates onshore in 1985 over 1970 was largely caused by a change in mix as older, cheaper, less efficient rigs were removed from the drilling fleet. This was offset by increases in observed rig productivity, as total completions per rig in the United States increased from 27 in 1970 to 36 in 1985, as discussed in Appendix D. This increase in observed "rig productivity" was caused by several factors, all of which tended to reduce completed well costs.

Offshore drilling moved to a different environment between 1970 and 1985, causing a tripling of completion costs in 1982 as compared to 1970, while contract drilling rates more than doubled over the same time period. Between 1981 and 1985, jackup contract drilling rates plummeted by a factor of three, while offshore completed well costs decreased by one-third. The wells completed per rig in offshore Louisiana decreased from 11 in 1970 to only 7 in 1984, as drilling moved into deeper water and

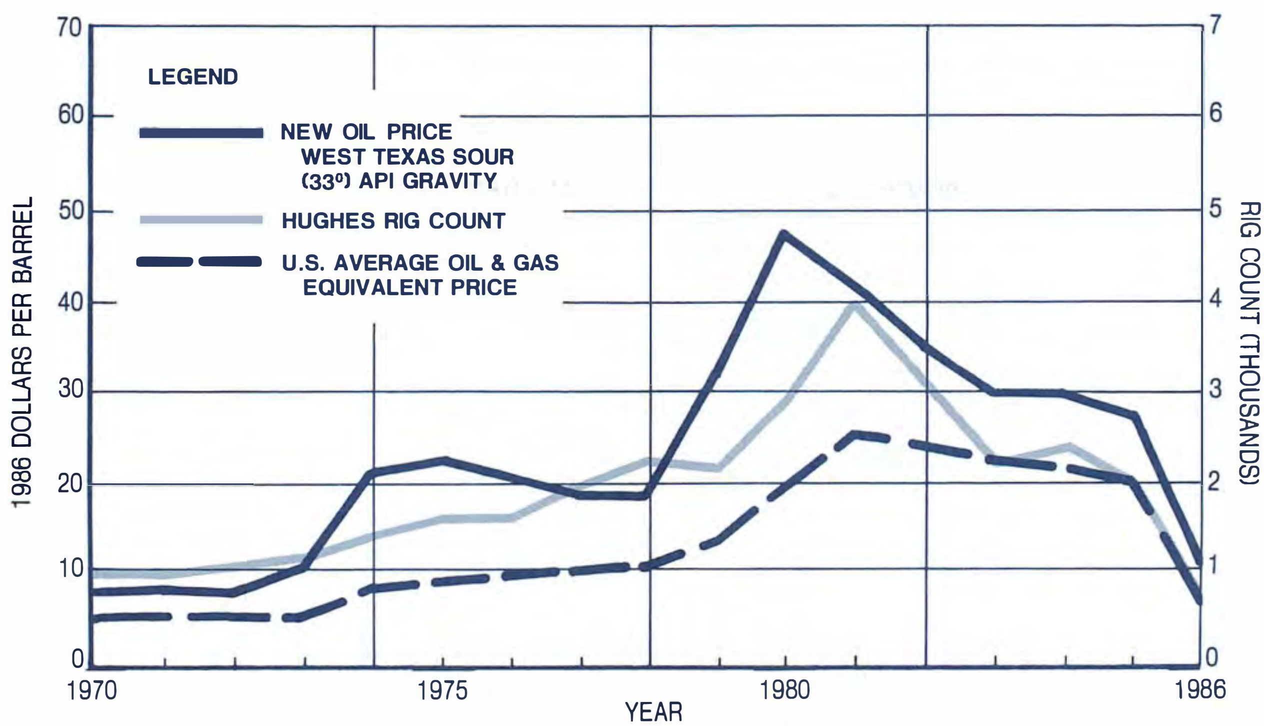


Figure 34. U.S. Wellhead Crude Oil and Natural Gas Price vs. Drilling Rig Activity Levels.

TABLE 19

IMPACT OF PRICE CHANGES ON CONTRACT DRILLING RATES AND COMPLETED WELL COSTS (1986 Dollars)

	Contract Drilling Rates (Dollars Per Day)		Completed Well Costs (Million Dollars)	
	Jackup Rig in 200 Ft. Water	10,000 Ft. Onshore Rig	10,000 Ft. to 12,500 Ft. La. Offshore	5,000 Ft. to 7,500 Ft. West Texas
1970	16,400	2,700	1.5	0.16
1975	28,300	4,800	2.1	0.29
1981	34,600	7,300	4.3	0.44
1982	37,800	5,700	4.5	0.42
1983	31,900	4,400	3.3	0.34
1984	22,900	4,300	3.3	0.29
1985	11,300	3,700	3.1	0.28
1986	9,000	3,600	N/A	N/A

as larger platforms were installed, requiring more directional drilling. Other factors that also reduced the cost per well and more than offset lower jackup contract drilling rates are: less erosion in offshore contract drilling rates for non-jackup rigs, increases in platform costs as drilling moved into deeper water, increases in required rig capabilities and casing requirements due to a shift to both deeper water and the capability of drilling deeper pay zones, and the incurrence of additional costs to comply with the Minerals Management Service, Environmental Protection Agency, and Coast Guard regulations.

The Effect of Prices on Drilling and Reserves

Proved reserves of oil and gas provide the inventory from which production of oil and gas is drawn. The total remaining reserves decrease by the amount of production unless they are replaced through reserve additions. Enhanced recovery methods and workovers can increase reserves and the production rate from a given amount of reserves.

As shown in Figure 35, oil and gas reserve additions correlate positively with well completions. As drilling remains depressed, the rate of new reserve additions will decline and production will eventually fall as a result. Even if the price goes back up, production in the lower 48 states will remain below the 1985 level because of the drilling decline. It has taken five years of drilling an average of over 80,000 wells annually to get production to remain steady. The current fall-off in drilling will undermine much of what has been gained since 1979.

As shown in Figure 36, production in the lower 48 states would have continued to decline after the mid-1970s without the additional drilling brought about by higher prices. The declining trend in wells drilled per year during the 1960s was reversed in the 1970s, yielding additional production volumes. In 1985, oil production from the lower 48 states would have been 1.7 MMB/D lower than was actually achieved without this reversal in the declining trend in wells drilled per year.

Using the responses to the NPC survey as indicators of future drilling activity through the year 2000, it is apparent that the U.S. domestic petroleum industry will not maintain existing oil and gas production levels if either of the two assumed price trends occur. The availability of adequate investment capital will prove to be a major constraint, and the industry will use existing reserves at a rate greater than they can be replaced.

There are two traditional financial measures of revenue reinvestment rates. The first measure expresses the expenditures spent for drilling and equipping wells as a percentage of total net wellhead revenue. As shown in Table D-13 in Appendix D, this measure has ranged

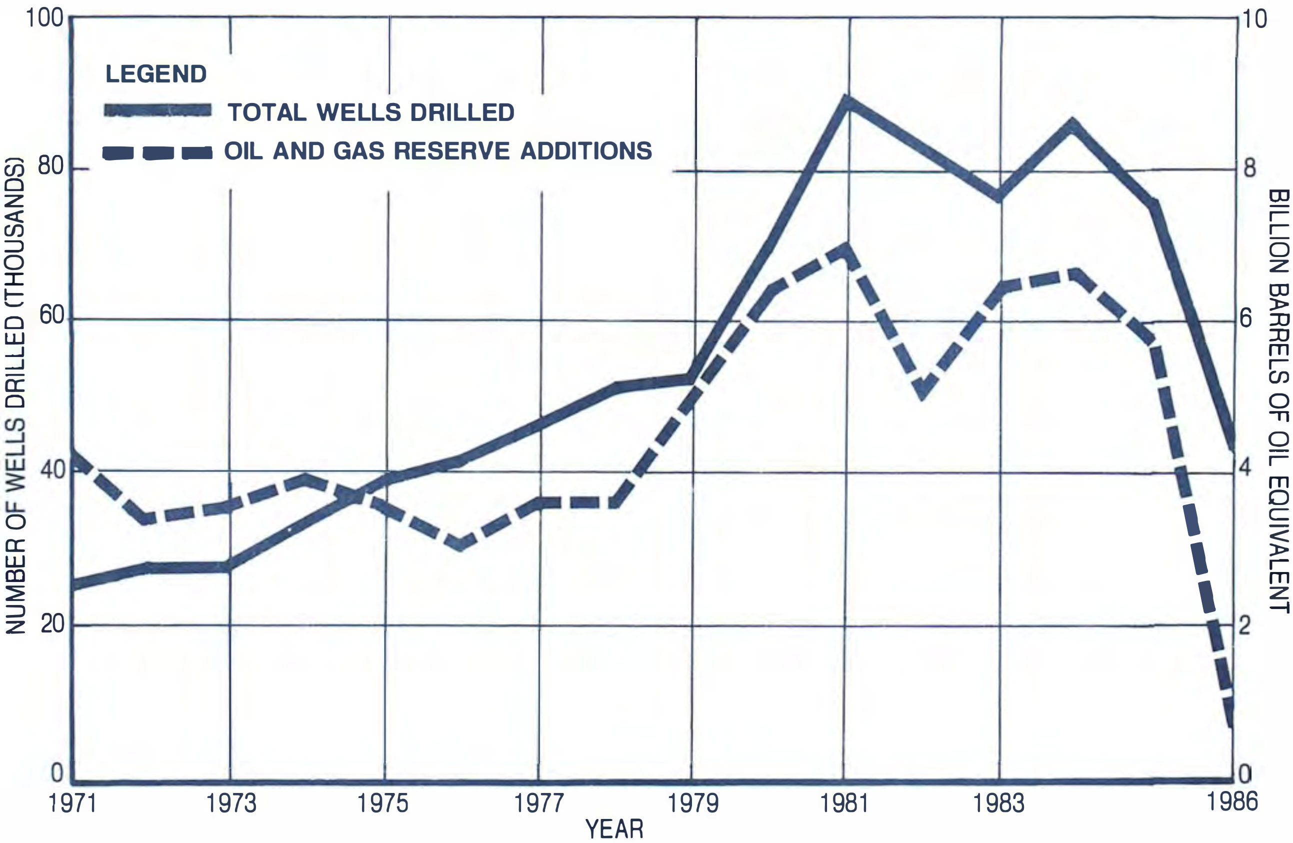


Figure 35. Oil and Gas Reserve Additions vs. Total Wells Drilled.

from 18 to 34 percent during 1970 through 1985, with the latter being achieved in 1982. It is estimated that this reinvestment ratio fell to 23 percent in 1986.

The second measure expresses the total expenditures spent in leasing, seismic, drilling, equipping, and producing oil and gas as a percentage of total net wellhead revenue. During the 1970–85 period, the petroleum industry has reinvested 64 to 97 percent in these efforts. However, in only one period has the 90 percent range been exceeded; this was in the 1981–82 period and was the result of the early 1980s expectation by the industry and investment community that the price of crude oil would rise to $50 to $75 per barrel.

Oil and natural gas prices have a two-fold impact on exploration and development (E&D) spending, and hence on drilling and reserve additions. Current prices are the primary determinant of the current cash flow of producers and hence their ability to fund capital expenditures. Further, longer-term price expectations heavily influence expected rates of return on potential drilling projects, and declines in the current prices received by the industry have generally been accompanied by a corresponding dampening in long-term price expectations as well.

Figure 37 shows the petroleum industry's U.S. expenditures to find, develop, and produce oil and gas. It does not include federal and state income taxes, dividends, and interest payments. Average wellhead crude oil prices are also shown for comparison in Figure 38.

The expenditure data in Figure 37 are discussed in Appendix D. These expenditures do not include property acquisition expenditures, as these were considered transfer payments within the industry.

The relationship between E&D expenditures (the lower two bands shown in Figure 37) and the average U.S. wellhead price of crude oil (shown in Figure 38), in general, is very close. Since 1978, however, capital spending has tended to be even more volatile than crude oil pricing. During the 1974–79 period, E&D spending increased more rapidly than prices. In the late 1970s, many in the industry anticipated price increases stemming from U.S. price decontrol and geared up for greater E&D spending. Then, in 1980 and 1981, crude oil prices rose even more sharply than E&D spending due to the impact of the Iranian revolution.

From 1981 to 1985, real E&D spending has declined by 44 percent while the real U.S. wellhead price of oil has declined by 36 percent. Many factors were responsible for E&D expenditures declining more sharply than crude oil prices between 1981 and 1985:

- *Sharp declines in drilling costs*—Drilling costs dropped far more sharply than crude oil prices.
- *Sharp declines in lease acquisition costs*—In 1985, total lease acquisition costs, both onshore and offshore, were down over 50 percent from 1984.
- *Financing constraints (external finance)*—For practically all independent producers and many majors, access to external finance has been seriously restricted. In 1981–82, commercial banks were willing to provide up to 70 percent of the funds required to develop a project. That proportion declined to less than 50 percent by 1985. Further, with declines in drilling funds and sharp declines in equity values, far less equity finance is available.
- *Financing constraints (internal cash flow)*—As internal cash availability has declined with declining prices and revenues, there has not been a corresponding decline in some uses of funds. In particular, outstanding interest and principal payments are due to creditors, and many producers are maintaining dividend payments. Consequently, E&D spending bears the greatest decline as total fund sources plummet.
- *Industry restructuring*—In an attempt to maintain shareholder value, some companies have increased debt at the expense of equity, often through debt-financed mergers and acquisitions. Producers with the highest percentage of debt-to-equity have generally cut capital spending the most.
- *Declines in reserve purchase prices*—As oil prices have declined, so too have reserve prices. With a growing number of independent producers in need of cash, distress sales of reserves have increased sharply. Consequently, producers are finding it cheaper to acquire reserves through acquisitions than through drilling.
- *Tax considerations*—Through the early 1980s, effective tax rates for oil found outside the United States have generally been considerably higher. This differential tax advantage in favor of U.S. production has served to offset the higher finding costs for U.S. oil. Over the past few years, however, several foreign governments have liberalized taxing regimes, while the United States is now moving to tighten tax provisions. Consequently, a greater percentage of E&D spending by multinational producers is now being devoted to areas outside the United States.

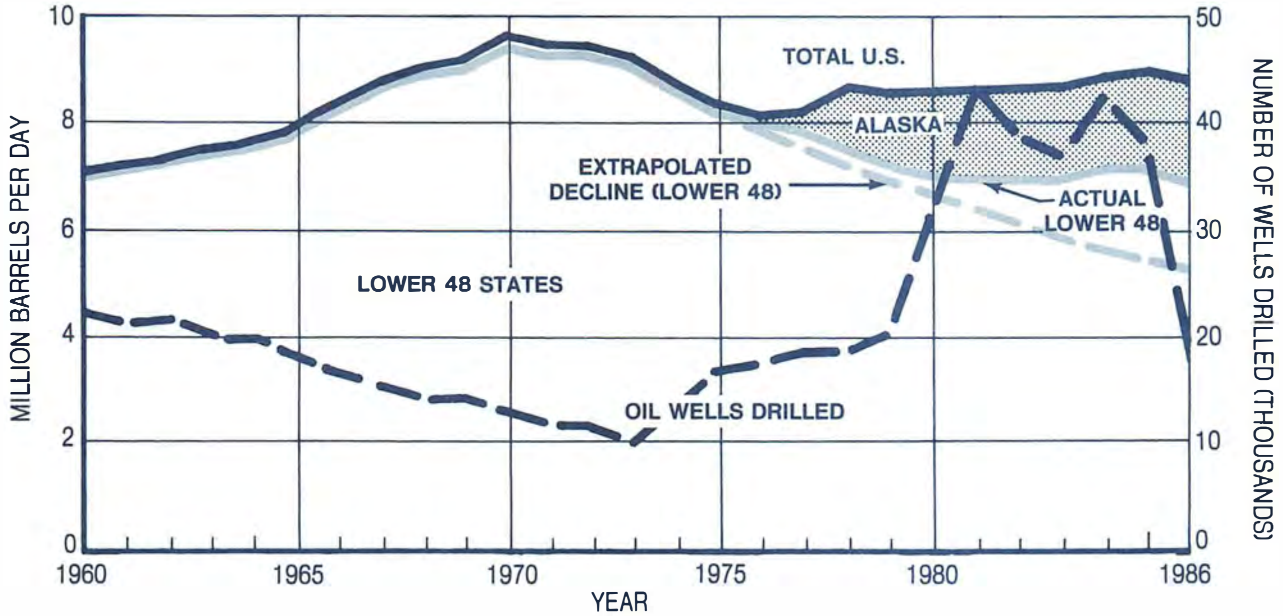


Figure 36. U.S. Crude Oil Production, Actual and Normal Decline, and Oil Wells Drilled.

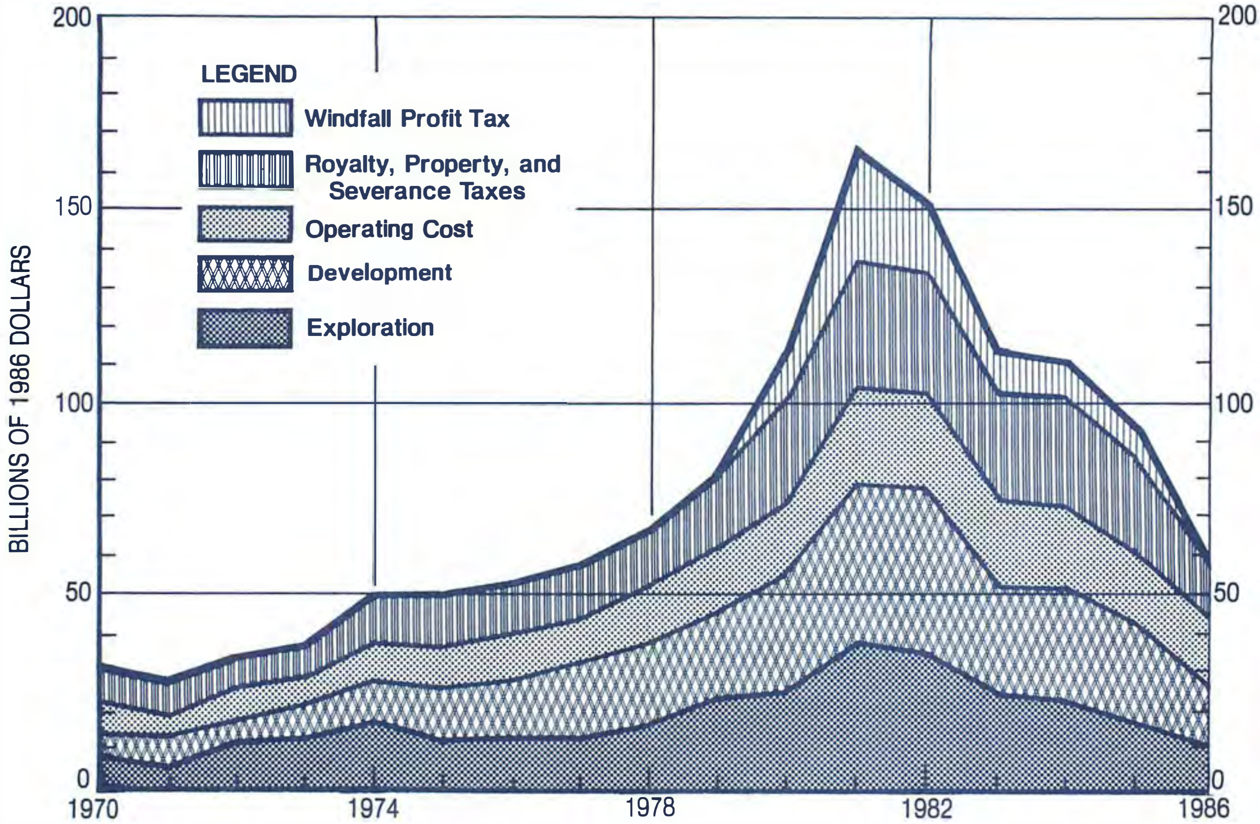


Figure 37. U.S. Exploration, Development, and Production Expenditures (Constant 1986 Dollars).

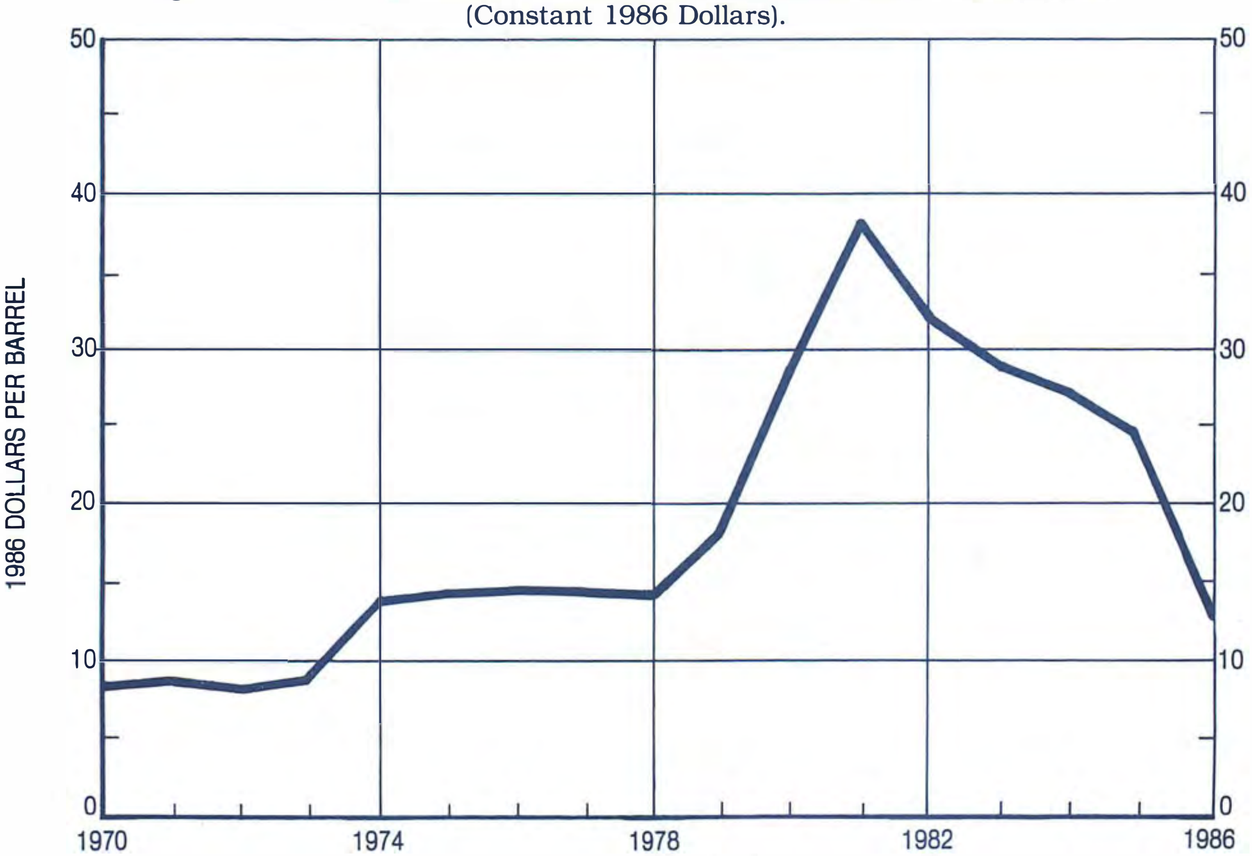


Figure 38. Annual Average U.S. Wellhead Oil Price (1986 Dollars per Barrel).

The Effect of Prices on Oil Production

The decisions to produce a well or invest so that oil and gas production can be initiated or maintained depend on actual and expected prices for the oil produced. For wells that are producing, it is an oversimplification to assume that they will either continue producing so long as revenues from the sale of the oil exceed the operating costs of the well, or be shut in if costs exceed revenue. In assessing the decision to shut in a producing well, some or all of the following factors will be included in addition to profitability:

- The physical characteristics of the reservoir
- The shutdown and startup costs associated with the well
- The anticipated level and path of future prices
- The regulatory and/or contractual requirements associated with the well
- The operator's need for short-term cash flow.

For example, wells may continue operating even though revenue from production does not cover operating or out-of-pocket costs if the operator expects future prices to be higher and the well's shutdown and startup costs are significant. Alternatively, if shutdown and startup costs are low, an operator may decide to stop producing a well even if current prices meet or exceed operating costs if he believes that selling the well's output later will maximize his income. Additionally, operating costs may differ among operators.

When investments are required to maintain or initiate production, the decision rests not on operating costs alone, but on the total costs of the well or field operation. Thus an investor will only make an investment to obtain production if he expects the present value of the net revenue stream, discounted at his cost of capital, to equal or exceed the required investment. Expectations of future prices and costs are critical to such investment decisions. Current or actual prices are involved since they are central to determining future price expectations.

Because decisions to continue production or to shut in a well are complex, precise forecasts of the rate of production under different price assumptions are difficult. Nonetheless, it is correct that production will decline when prices decrease since some wells are no longer profitable to operate. If prices remain at depressed levels for a period of time, production will further decrease as more wells become uneconomic, as fewer wells are drilled to offset the natural decline in production, and as a history of lower prices works to change perceptions of future prices. Conversely, higher prices will result in increased investment in oil production and thus production will increase, though the resulting increased production lags the price increase.

A brief examination of the domestic industry's history during the 1970s illustrates this responsiveness to price change. Domestic production of crude oil and lease condensate peaked in 1970, when the price of oil was $3.18, or $8.93 in 1986 dollars. Prices in 1986 dollars increased only 4 percent through 1973 and then increased about 60 percent in 1974 as a result of the Arab oil embargo. During this period, U.S. production fell from 9.6 MMB/D in 1970 to 9.2 MMB/D in 1973. Figure 37 shows that exploration and development investments in oil and gas production activities were increased in 1973 by 39 percent above their 1970 levels in 1986 dollars. This was primarily due to increased activity in the Outer Continental Shelf as more federal acreage was offered for leasing. The first price shock of 1973 was reinforced by the second shock that resulted from the revolution in Iran. Figure 38 shows that prices of domestic crude oil in 1981 were 330 percent higher than the 1973 prices in real terms. Simultaneously, exploration and development investment in 1986 dollars increased from around $20 billion in 1973 to over $79 billion in 1981, or by 295 percent.

The level of domestic crude oil production lagged the price and investment increase. Production continued to fall from its 1973 level to 8.1 MMB/D in 1976, when the production decline was halted and domestic production began a gradual increase rising to 8.9 MMB/D in 1985. This reversal of the production decline was a result of the combination of incremental production from increased E&D investment in the lower 48 states and the initiation of production from the Prudhoe Bay and Kuparuk River fields on the North Slope of Alaska. (See Figure 36.)

U.S. Gas Supply

Total U.S. gas supply peaked in 1972 at more than 22 TCF. The impacts of low regulated prices on U.S. gas production and the inability to expand Canadian exports because of the National Energy Board restraints led to a decline in U.S. gas supply to about 20 TCF by 1975. Supplies stabilized at this level through 1981, as increasing price ceilings led to increased exploration and development in the United States and increased availability of Canadian gas in U.S. markets. Since 1981, reduced activity in many large gas-using industries, a shift in the industrial structure toward less gas-intensive industries, fuel switching, and conservation resulted in only 17 TCF of gas supplies being required by U.S. gas customers in 1985. Despite this reduction in the consumption of gas, total supply availability remains in excess of 20 TCF.

Of the actual supply used in 1985, about 95 percent came from domestic production. Most of the remainder was supplied from Canadian imports, with small amounts from other sources, such as synthetic gas from coal or petroleum.

Most projections of future U.S. gas supplies that were prepared prior to the 1986 oil price drop expected total U.S. gas supplies from all sources to continue to maintain the 1985 level of about 18 TCF through the year 2000. The EIA Annual Energy Outlook 1985 (low imports case) forecast that total U.S. gas supply would increase to 18.5 TCF in 1995. Such projections, however, also recognized that, at wellhead prices competitive with alternative fuels, conventional production in the lower 48 states would decline over time and increasing amounts of supplementary supplies, primarily imports from Canada, and incremental production from unconventional gas sources, would be required.

Lagged Response in Exploration and Production to Changes in Price

Oil and gas exploration and production is a long lead time business. An offshore project can easily take up to 10 years to advance from preliminary geological and geophysical work to initial production. An EOR project can take a similar length of time to move from preliminary engineering, through a test program, drilling injection wells and injecting fluid, to the beginning of tertiary production. Frontier areas, such as deep water Gulf of Mexico, which are believed to contain much of the nation's future oil and gas reserves, may require 10 or more years before production can be obtained. In Alaska, where there is also great potential, production can require 15 years or more to come on stream.

Today's oil and gas production still benefits from the high oil and gas prices of the late 1970s and the first half of the 1980s. These prices encouraged borrowing and generated revenue that was plowed back into exploration and development. The drilling boom of the late 1970s and early 1980s was fed by the expectations of ever-rising oil and gas prices.

Conversely, decisions not to invest because of today's low prices have a negative impact that will not be visible for years to come. Furthermore, when prices begin to rise, investors may react slowly, waiting until they can evaluate the upward price trend as sustainable.

The oil and gas service sector has been hit especially hard. Many firms have declared or are on the verge of bankruptcy. Some firms have been forced to combine with others. Barring a quick rebound in oil field activity, many skilled people will be lost from the industry. When oil and gas prices rebound, the lessened competition and the shortage of experienced people will cause increased costs and unavoidable delays in resumption of drilling activity and new reserve additions. Resulting production may lag discoveries even more than in the past. The longer the current price slump lasts, the worse this problem becomes.

Financial institutions, which have historically supported the various components of the oil and gas industry, have also been stung by the rapid decline in oil and gas prices. These institutions now have increasing levels of nonperforming and underperforming loans, resulting in a retrenchment of their loan portfolios and an unwillingness, if not inability, to make available additional funding.

Capital for new project financing will again be made available when investors have rebuilt their confidence in the liquidity of the industry and perceive a sustainable higher price. Outside capital has traditionally come from a variety of sources. A particularly important channel for independent producer financing in the early 1980s was the private and public drilling and production funds. Registered funds invested a peak of $4.0 billion in drilling and production acquisition in 1981. Tax rates and the oil price outlook brought later figures down, and in 1986 the funds supplied $0.3 billion. To the extent the upstream oil sector cannot attract outside capital, it will be restricted to its depressed internal cash flow for investment in new exploration and development projects.

THE NPC OIL & GAS OUTLOOK SURVEY AND IPAA/SIPES DRILLING SURVEY

Oil & Gas Outlook Survey

Currently, considerable uncertainty exists over the likely future evolution of crude oil prices. Expected price weakness in the short-term results from the major supply overhang from OPEC producers (with production capacity close to 27 MMB/D). Saudi Arabia is playing a key role by foresaking its self-appointed balancing role in seeking to assure its longer-term markets.

In the longer term, the price uncertainties relate principally to the role that OPEC or individual OPEC countries will play in establishing prices and the likely future response of both oil supply and demand to different price levels.

As one tool for analyzing other factors affecting oil and gas supply and demand, a survey of future supply/demand outlooks was made using two oil price trends provided by the Department of Energy: an upper price trend starting at $18 per barrel and rising at 5 percent per year in real terms, and a lower price trend starting at $12 per barrel and rising at 4 percent per year in real terms.

Refiner Acquisition Cost of Crude Oil 1986 Dollars Per Barrel

	1986	1990	1995	2000
Upper Price Trend	18	22	28	36
Lower Price Trend	12	14	17	21

The survey respondents were requested to assume there would be no change in present laws (e.g., no early deregulation of natural gas, no early phaseout of the Windfall Profit Tax, continuation of current tax law), no changes in environmental regulations or leasing policies, no drastic changes in the world (such as major wars, revolutions, or the end of OPEC), no dramatic changes in exchange rates among the world's currencies, no worldwide banking or financial crises, no new major technological breakthroughs in either the production or consumption of energy, and that refining capacity would be adequate.

The oil price trends used in the NPC Oil & Gas Outlook Survey begin at low levels compared to the perspective that existed in 1985. These lower price trends imply renewed growth in demand and lower estimates of domestic production. There are many other price scenarios that could develop between today and the year 2000. These include a scenario where prices do not rise in real terms for several years, after which prices rise rapidly due to growing supply and demand pressures. Another possible scenario could include a strong price increase in response to a renewed effort by OPEC to control supply, resulting in a return to 1985 prices. If this were to occur, weaker demand and higher levels of domestic production would ensue.

Wellhead gas prices are expected to be capped through a netback from the burnertip in competition with low sulfur residual fuel oil prices so long as the gas bubble continues. Once the gas bubble ends, in order to balance U.S. natural gas supply and demand, burnertip gas prices will need to rise above the low sulfur residual fuel oil price (assuming low oil prices) to reduce potential demand, mostly through switching back to residual fuel oil.

The NPC survey was designed to elicit future supply and demand levels that are believed by the respondents to be likely if the price trends specified were to occur and all the assumptions specified were to prevail. It is recognized that future oil prices will not follow either of these trends. The price trends are not forecasts of future prices, but are intended to suggest a range of plausible prices, and more importantly, provide insight into the impact of lower prices on the oil and gas outlook. The results are included in Appendix D.

Drilling Survey

The IPAA/SIPES Drilling Survey was sent to the independent producers and petroleum technical specialists responsible for the investment and drilling decisions for the majority of the oil and gas wells drilled in the United States. Respondents were requested to estimate their level of participation in drilling activity for each of the next five years, assuming average oil and gas prices of $13 per barrel and $1.30 per MCF respectively; $20 per barrel and $2.40 per MCF; and $27 per barrel and $3.50 per MCF. The first two oil price assumptions approximate the 1986–90 prices of the lower and upper price trends, respectively, of the NPC survey. The $27 price assumption was selected as being representative of the price levels experienced by the industry prior to the recent severe price decline.

At an oil price of $13 per barrel, the 1,023 respondents expect their drilling to decline to 18 percent of the 1985 level in 1987, and to further decline to 15 percent in 1990. At a price of $20 per barrel, drilling would fall to half the 1985 level by 1987 and remain at that level through 1990. Finally, at $27 per barrel, drilling would increase about 7 percent by 1987, then increase steadily to about 124 percent of the 1985 level in 1990.

Similarly, in March 1986, the American Petroleum Institute surveyed 21 large integrated petroleum companies to investigate the effect of lower prices. Like the IPAA/SIPES Drilling Survey, the results of the API Crude Oil Price Effects Survey indicate that there would be a sustained decline in drilling activity under low price scenarios. The API survey indicates that well completions would be 31,100 in 1991 under a constant $15 per barrel scenario (1985 dollars), a decline of 60 percent; and 12,500 under the $10 per barrel scenario, an 80 percent decline. The API survey respondents projected relatively unchanged drilling activity (73,400 completions in 1991) if prices had stayed at the 1985 level of $28 per barrel.

The NPC survey responses also show a substantial decline in drilling activity during the next five to ten years compared to the record high of 1981–85. From an annual average of over 80,000 wells during that period, drilling declines 67 percent to a mean of 27,100 wells per year in 1986–90 in the lower price trend and declines 42 percent to 47,200 wells per year in the upper price trend. As real prices increase, drilling increases as well. (See Table 20 and Figure 39.)

TABLE 20

SURVEY RESPONSE
TOTAL ANNUAL WELLS DRILLED

	Mean Number of Wells Drilled Per Year			
	Actual			
1981-1985	82,000			
	Lower Price Trend		Upper Price Trend	
	Wells	Rigs*	Wells	Rigs*
1986-1990	27,100	874	47,200	1,523
1991-1995	38,400	1,239	56,300	1,816
1996-2000	41,500	1,339	66,200	2,135

*Based on 1981-85 average rotary rig productivity of 31 wells per rig (see Appendix D).

Reserve Additions

With the indicated decline in drilling, reserve additions also drop (Table 21). Compared with reserve additions averaging 2.72 billion barrels of oil and 15.9 TCF of gas per year from

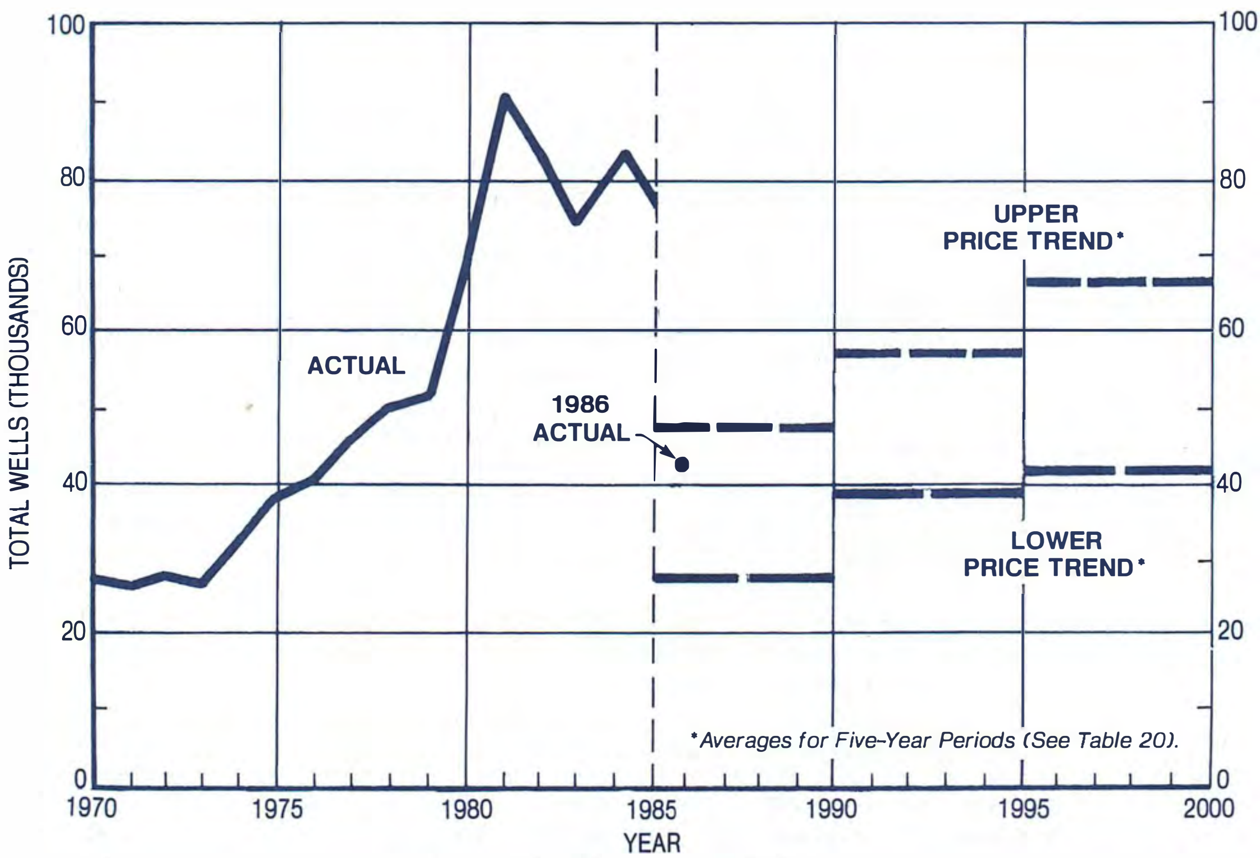


Figure 39. Total Wells Drilled (NPC Oil & Gas Outlook Survey).

TABLE 21

SURVEY RESPONSE—DOMESTIC RESERVES AND AVERAGE ANNUAL RESERVE ADDITIONS (AARA) 1985–2000

	Lower Price Trend		Upper Price Trend	
	Reserves	AARA	Reserves	AARA
Crude Oil and Condensate (Billion Barrels)				
Reserves, 12-31-85	29.9		29.9	
AARA 1986–90		1.33		2.01
Reserves, 12-31-1990	21.9		24.5	
AARA 1991-95		1.36		1.90
Reserves, 12-31-1995	16.8		20.4	
AARA, 1996–2000		1.36		1.90
Reserves, 12-31-2000	14.5		18.1	
Natural Gas, Wet (Trillion Cubic Feet)				
Reserves, 12-31-1985	202.2		202.2	
AARA 1986–90		7.8		11.8
Reserves, 12-31-1990	157.9		175.5	
AARA 1991-95		10.4		13.2
Reserves, 12-31-1995	134.5		159.0	
AARA 1996–2000		10.9		13.9
Reserves, 12-31-2000	121.6		151.0	

1981 to 1985, oil reserve additions decline 50 percent in 1986–90, to only 1.33 billion barrels of oil per year. Gas reserve additions also decline 50 percent, to 7.8 TCF of gas per year in the lower price trend. Likewise, reserve additions decline 25 percent, to 2.01 billion barrels of oil per year, and decline 25 percent, to 11.8 TCF of gas per year, in the upper price trend. Even with increasing real prices and increased drilling rates, crude oil reserve additions do not increase from these initial rates through 2000. On the other hand, reserve additions for natural gas do increase from the late 1980s to the 1990s (by 40 percent in the lower price trend and by 18 percent in the upper price trend).

The survey responses indicate a shift in emphasis from oil to gas under both price trends. Possible causes for this shift in emphasis are as follows:

- Oil exploration is more mature than gas exploration and has already experienced real price levels that are higher than those in both price trends.
- Natural gas development has been restricted in recent years and will be restricted during the 1985–90 time period by the gas bubble. The end of the gas bubble will cause an increase in natural gas exploration and development activity.

Despite the increase in drilling and the decline in domestic production, in neither price trend for either oil or gas are reserve additions during the late 1990s sufficient to replace production. Thus in both price trends for both oil and gas, reserves decline throughout the period, albeit at decreasing rates. From 1985 to 2000, crude oil reserves are shown to decline 52 percent in the lower price trend and 39 percent in the upper price trend. Excluding the 27 TCF of natural gas reserves in the North Slope of Alaska, which are included in the DOE reserve base but are not expected to contribute to domestic supply before the year 2000, natural gas reserves decline 46 percent in the lower price trend and 29 percent in the upper price trend. The decline in domestic reserve-to-production ratios for the two price trends surveyed are discussed in Appendix D.

U.S. Oil Supply

The NPC survey trends for domestic oil production and oil imports are shown in Table 22 and Figure 40. U.S. oil production falls in both price trends. Domestic liquids production falls

TABLE 22

SURVEY RESPONSE
U.S. OIL SUPPLY/DEMAND BALANCE
(Million Barrels Per Day)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Domestic Consumption	15.7	16.3	17.0	17.4
Domestic Crude Oil Production	9.0	8.0	7.0	6.4
NGL and Other Supply	2.5	2.1	2.1	1.9
Total Domestic Supply	11.5	10.1	9.1	8.3
Net Imports Needed to Meet Demand	4.2	6.2	7.9	9.1
Imports as a Percent of Consumption	27%	38%	47%	52%
Lower Price Trend				
Domestic Consumption	15.7	17.6	19.0	19.9
Domestic Crude Oil Production	9.0	7.1	5.7	4.5
NGL and Other Supply	2.5	2.1	1.9	1.8
Total Domestic Supply	11.5	9.2	7.6	6.3
Net Imports Needed to Meet Demand	4.2	8.4	11.4	13.6
Imports as a Percent of Consumption	27%	48%	60%	68%

29 percent between 1985 and 2000 for the upper price trend. Under the lower price trend, domestic liquids production decreases 48 percent.

In the upper price trend, crude oil production declines from 9.0 MMB/D in 1985, to 8.0 MMB/D in 1990, to 7.0 MMB/D in 1995, and to 6.4 MMB/D in 2000. In the lower price trend, crude oil production declines much more rapidly—to 7.1 MMB/D in 1990, 5.7 MMB/D in 1995, and only 4.5 MMB/D in 2000. According to the EIA Annual Energy Outlook 1985, for the low imports case (see Table 23), crude oil production falls to 8.4 MMB/D in 1990 and to 7.4 MMB/D in 1995.

U.S. net oil imports increase from 4.2 MMB/D in 1985 to 9.1 MMB/D by 2000 in the upper price trend, and to 13.6 MMB/D in the lower price trend.

The two price trends impact various types of domestic liquids production differently. A summary of domestic production of crude oil and condensate, by production category for the two price trends, is shown in Table 24.

Production from existing fields falls in both price trends, but the rate of decline is greater in the lower price trend (5.2 percent per year between 1985 and 2000) than it is in the upper price trend (3.5 percent per year). Production from existing wells decreases at about the same rates in both the upper and lower price trends. However, production resulting from new investment in existing fields increases much less rapidly in the lower price trend.

EOR production is both technically complex and costly. Hence, EOR production is generally considered marginal. The survey results reflect this fact. EOR production grows in the upper price trend from 550 MB/D in 1985 to 848 MB/D by 2000, or 13 percent of total domestic liquids production. With both lower price levels and price growth in the lower price trend, EOR production falls from the estimated level of 550 MB/D in 1985 to 382 MB/D in 2000. These results are reasonably consistent with the estimates of EOR production developed in the 1984 NPC study, *Enhanced Oil Recovery*.[1]

At the request of the DOE, Lewin and Associates, Inc., and the U.S. DOE Bartlesville Project Office re-estimated potential crude oil production from enhanced oil recovery based on

[1]Based on the methodology developed in the 1984 NPC study, *Enhanced Oil Recovery*, with updated projections made by Lewin and Associates, Inc.

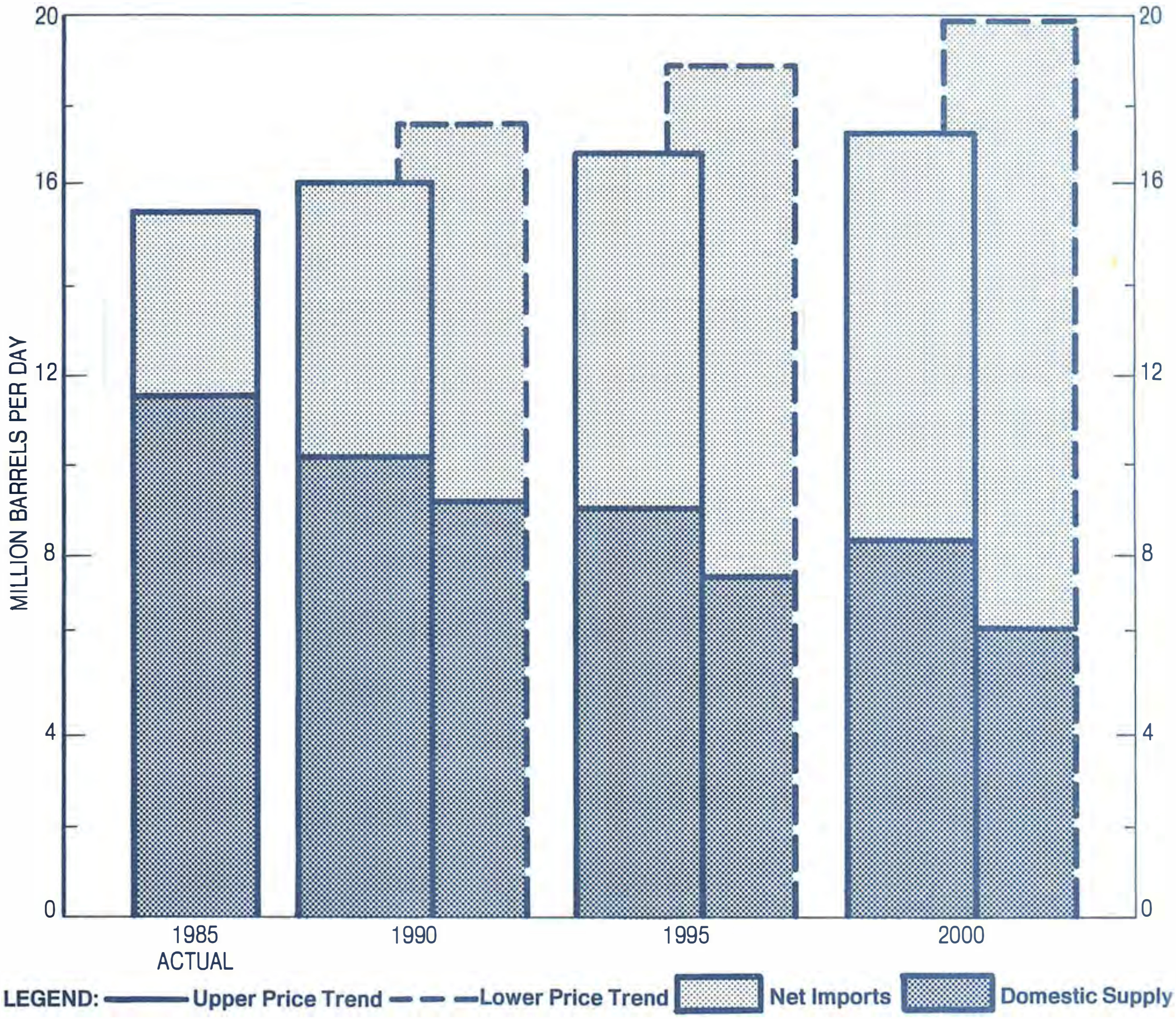


Figure 40. U.S. Oil Supply/Demand Balance.

the 1984 NPC *Enhanced Oil Recovery* study. A copy of the detailed study—including the methodological changes and assumptions used to make the study consistent with the upper and lower price trends—is available from the NPC. The results of this study are summarized in Table 25.

The survey and updated 1984 NPC study estimates for EOR production are similar for 1990 but diverge thereafter. Based on the 1984 NPC study methodology, EOR production could be about 30 percent higher in the year 2000 than the survey results indicate, regardless of the price trend analyzed. This difference may arise because the 1984 NPC study did not consider a number of potentially constraining factors such as cash flow and capital availability.

New discoveries are also price sensitive, and this is again reflected in the survey. Production from new discoveries is expected to grow in both price trends, but the volume of production is over twice as high at the higher price levels. The majority of production from new discoveries is expected to come from the onshore area of the lower 48 states, although new discovery production grows at about the same rate in both the onshore and offshore areas (see Appendix D). Synthetic liquids do not make a significant contribution to supply in either price case.

Production from stripper wells (wells producing less than 10 barrels per day) was reported separately in the survey because of its importance to much of the industry and country (see Appendix D). Stripper well production

TABLE 23

ENERGY INFORMATION ADMINISTRATION
U.S. OIL SUPPLY/DEMAND BALANCE
ANNUAL ENERGY OUTLOOK 1985
LOW IMPORTS CASE*
(Million Barrels Per Day)

	Actual 1985	1990	1995
Domestic Consumption	15.7	15.4	15.7
Domestic Crude Oil Production	9.0	8.4	7.4
NGL and Other Supply	2.5	2.3	2.2
Total Domestic Supply	11.5	10.7	9.6
Net Imports Needed to Meet Demand	4.2	4.7	6.1
Imports as a Percent of Consumption	27%	31%	39%

*Oil prices in 1985 dollars: 1986—$27, 1987—$27, 1988—$29, 1989—$31, 1990—$32, 1995—$37.

has historically been sensitive to price changes.[2] The survey indicates that stripper production remains at its 1985 share of total production (14 percent) in the upper price trend. In the lower price trend, stripper well production declines more rapidly than total production and its share of total production falls gradually from its 1985 level of 14 percent to approximately 10 percent by the year 2000.

If a stripper well is plugged, the associated reserves may be permanently lost. Total stripper well reserves (4.5 billion barrels) represent about 16 percent of total U.S. oil reserves and 23 percent of oil reserves in the lower 48 states. Lastly, stripper well activity represents over 70 percent (460,000 of 650,000 wells) of all the active oil wells in the United States.

U.S. net oil imports under the lower price trend could rise dramatically from about 27 percent of domestic consumption in 1985 to almost 50 percent in 1990, about 60 percent in 1995, and almost 70 percent in 2000. This represents greater oil import dependence than occurred in the United States in the late 1970s. In the upper price trend, import levels rise to over 35 percent in 1990, over 45 percent in 1995, and over 50 percent in 2000.

[2]U.S. General Accounting Office, *Energy R&D: Current and Potential Use of Enhanced Oil Recovery*. June 1986.

TABLE 24

SURVEY RESPONSE
U.S. CRUDE OIL AND CONDENSATE PRODUCTION BY TYPE
(Thousand Barrels Per Day)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Existing Fields	8,971	7,683	6,391	5,260
Developed Production	8,421	5,351	3,577	2,173
New Investment	—	1,727	2,104	2,239
Enhanced Oil Recovery	550*	605	710	848
New Discoveries	—	276	599	1,093
Total	**8,971**	**7,959**	**6,990**	**6,353**
Lower Price Trend				
Existing Fields	8,971	7,020	5,380	4,004
Developed Production	8,421	5,373	3,599	2,130
New Investment	—	1,182	1,387	1,492
Enhanced Oil Recovery	550*	465	394	382
New Discoveries	—	116	274	538
Total	**8,971**	**7,136**	**5,654**	**4,542**

*Estimated.

TABLE 25

POTENTIAL CRUDE OIL PRODUCTION FROM ENHANCED OIL RECOVERY*
(Thousand Barrels Per Day)

	1986	1990	1995	2000
Upper Price Trend				
Thermal	510	490	570	700
Miscible	70	140	260	370
Chemical	10	30	50	40
Total	**590**	**660**	**880**	**1,110**
Lower Price Trend				
Thermal	490	380	330	330
Miscible	60	70	100	130
Chemical	10	20	30	30
Total	**560**	**470**	**460**	**490**

*Based on the methodology developed in the 1984 NPC study, *Enhanced Oil Recovery*, with updated projections made by Lewin and Associates, Inc.

Even using a price path that rose from the 1985 level, net U.S. import dependency was expected to increase. According to the EIA Annual Energy Outlook 1985 low imports case, net imports were projected to increase to 31 percent in 1990 and 39 percent in 1995.

The NPC survey also indicates that, under the upper price trend, 30 percent of non-communist world demand will have to be supplied by Middle East OPEC in 1995 and 35 percent in 2000, up from 21 percent in 1985 (Table 26 and Figure 41). Under the lower price trend, this dependence rises to approximately 40 percent in 1995 and over 45 percent in 2000. Middle East OPEC possesses 63 percent of non-communist world proved crude oil reserves, and these countries could meet the higher export levels if they chose to do so. However, as OPEC production increases and surplus capacity declines, its members will have greater power to increase prices.

Under both price trends, U.S. gas consumption will be limited to available domestic supplies plus imports. Because gas imports are constrained, any shortfall in meeting the total demand for energy will almost certainly be filled by oil imports.

U.S. Gas Supply

The U.S. gas supply outlook from the NPC survey, on a dry basis, is shown in Table 27 and Figure 42. In both cases, under these two relatively low price trends, the supply/demand balance for natural gas will be limited by available supply—by 1990 in the lower price trend, and during the first half of the 1990s in the upper price trend.

For both price trends, U.S. gas production falls in the 1990s. With the higher price expectations of the upper price trend, by the year 2000 total production declines by 12 percent relative to the 1985 level of 16.4 TCF. In the lower price trend, the decline is 24 percent.

Increasing amounts of imports and other gas supplies will be required through the year 2000. These requirements are approximately the same in both trends, rising from 0.9 TCF in 1985 to about 2.6 TCF in 2000. Canada accounts for about 85 percent of these supplies. At the price levels included in the survey, Canadian imports are constrained by the availability of gas supplies and existing transmission capacity into the United States. Additional gas imports could be available at higher gas prices than assumed in the survey.

The probability of receiving substantial additional natural gas from Canada is low. This is due to:

- A reluctance to make the heavy investment in the necessary pipelines to bring the new natural gas from the frontier areas to market
- The probability that Canada, which is also interested in energy security and conservation, may not wish to export more natural gas than it does presently.

Gas imports from Mexico are not expected before the mid-1990s and account for only about 10 percent of total U.S. gas imports. It is expected that Mexico will continue to substitute gas internally for fuel oil and export the fuel oil where possible.

Table 28 contains a breakdown of wet gas production for existing fields and from new discoveries. These categories are further broken down between lower 48 states (onshore and offshore) and Alaska. Note that production decreases in the lower 48 states. Production in Alaska, which primarily serves consumption in Alaska along with some small LNG exports to Japan, is expected to remain constant. Alaskan production is from existing fields and will require relatively little new investment. No deliveries of Alaskan gas to the lower 48 states are expected through the year 2000. The level

TABLE 26

SURVEY RESPONSE
NON-COMMUNIST WORLD OIL SUPPLY/DEMAND BALANCE
(Million Barrels Per Day)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Total Consumption	46.5	48.2	50.5	52.5
Non-OPEC Crude Oil and NGL	25.2	24.7	23.9	22.5
Other Supply	4.1	2.9	2.6	2.5
OPEC Crude Oil & NGL Production	17.2	20.6	24.0	27.5
Total Supply	46.5	48.2	50.5	52.5
Memo: Middle East OPEC Crude Oil as a Percent of Total Supply	21%	25%	30%	35%
Lower Price Trend				
Total Consumption	46.5	51.0	54.7	58.0
Non-OPEC Crude Oil and NGL	25.2	22.4	20.4	18.6
Other Supply	4.1	2.8	2.5	2.4
OPEC Crude Oil & NGL Production	17.2	25.8	31.8	37.0
Total Supply	46.5	51.0	54.7	58.0
Memo: Middle East OPEC Crude Oil as a Percent of Total Supply	21%	32%	40%	46%

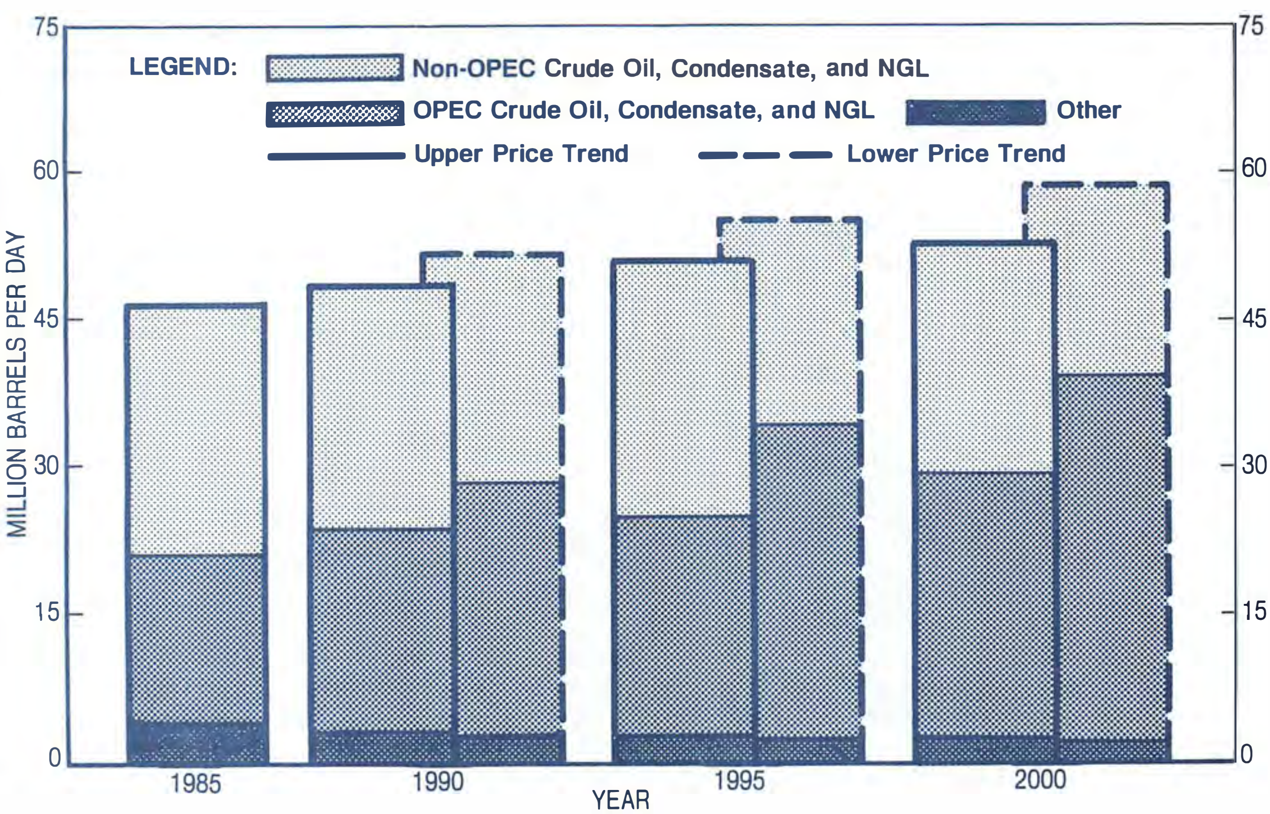


Figure 41. Non-Communist World Oil Supply/Demand Balance.

TABLE 27

SURVEY RESPONSE
U.S. NATURAL GAS SUPPLY/DEMAND BALANCE
(Trillion Cubic Feet Per Year)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Domestic Consumption	17.3	17.6	17.3	17.0
Domestic Production (Dry Gas)	16.4	16.4	15.2	14.5
Net Imports	0.9	1.3	2.2	2.6
Other Supply and Inventory Change	0.0	(0.1)	(0.1)	(0.1)
Total Supply	17.3	17.6	17.3	17.0
Memo: Unsatisfied Gas Demand*				
Replaced By Oil—TCF	—	—	<0.1	0.2
—MMB/D oil equivalent	—	—	<0.1	0.1
Lower Price Trend				
Domestic Consumption	17.3	17.0	15.5	15.0
Domestic Production (Dry Gas)	16.4	15.5	13.3	12.4
Net Imports	0.9	1.5	2.2	2.6
Other Supply and Inventory Change	0.0	0.0	0.0	0.0
Total Supply	17.3	17.0	15.5	15.0
Memo: Unsatisfied Gas Demand*				
Replaced By Oil—TCF	—	0.3	0.7	1.0
—MMB/D oil equivalent	—	0.1	0.3	0.5

*Reflects the amount by which natural gas supply (domestic production plus imports) fell short of natural gas demand after balancing the results of survey responses. At the price levels in the survey, imports are constrained by economics and transmission capacity. The resulting shortfall in gas supplies constrained natural gas consumption, and the unsatisfied demand was assumed to be filled by oil since oil and gas can be substituted in a large number of dual-fired boiler applications. Since some individual respondents could have converted unsatisfied gas demand to other forms of energy in their submittals, these unsatisfied gas demands could be understated.

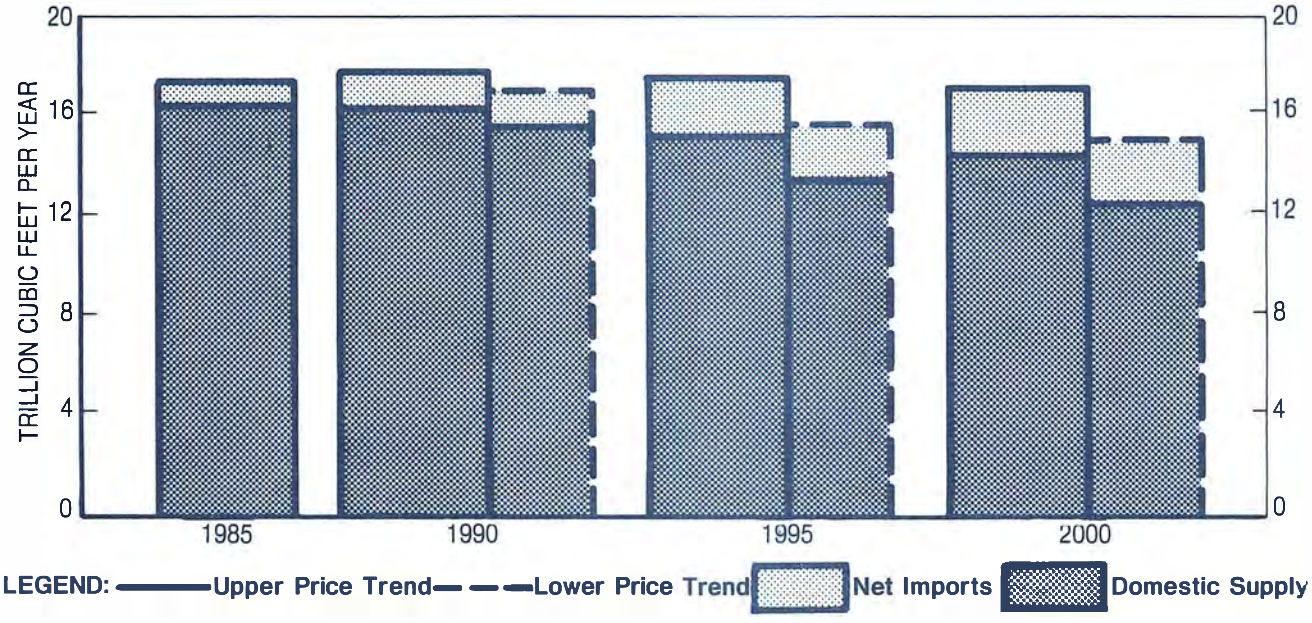


Figure 42. U.S. Natural Gas Supply/Demand Balance.

TABLE 28

SURVEY RESPONSE
LOWER 48 WET GAS PRODUCTION
(Billion Cubic Feet Per Year)

Source	Actual 1985	1990	1995	2000
Upper Price Trend				
Existing Fields	17,198	15,793	13,041	10,888
Lower 48	16,877	15,453	12,691	10,538
Onshore	12,245	10,581	8,469	7,040
Offshore	4,632	4,872	4,222	3,498
Alaska	321	340	350	350
New Fields		1,334	2,861	4,248
Lower 48		1,334	2,851	4,218
Onshore		716	1,455	2,367
Offshore		618	1,396	1,851
Alaska		0	10	30
Total	**17,198**	**17,127**	**15,902**	**15,136**
Lower Price Trend				
Existing Fields	17,198	15,225	11,914	10,090
Lower 48	16,877	14,885	11,564	9,740
Onshore	12,245	9,734	7,604	6,234
Offshore	4,632	5,151	3,960	3,506
Alaska	321	340	350	350
New Fields		962	2,060	2,921
Lower 48		962	2,050	2,891
Onshore		491	957	1,547
Offshore		471	1,093	1,344
Alaska		0	10	30
Total	**17,198**	**16,187**	**13,974**	**13,011**

of LNG imports into the United States is not expected to play a significant role in the future supply of energy for the United States under either price trend.

Gas production from existing fields in the lower price trend is expected to be between 4 and 7 percent lower through the year 2000 than in the upper price trend. Production from new fields, however, is reduced by over 30 percent in the lower price trend. The incremental investment to add production in an existing field involves both a lower capital requirement and lower risk and is therefore less sensitive to the expectation of lower oil prices. The high initial cost of exploration and the risk of investment in new fields makes these investments more sensitive to lower expected revenues.

The major effect of lower oil and gas prices is to onshore production. From 1985 to 2000, total onshore production declines by about 25 percent in the upper price trend and by over 35 percent in the lower price trend. Total offshore production increases by almost 1 TCF relative to 1985 in the upper price trend and remains about the same in the lower price trend.

Deep water offshore production requires much higher capital investments and longer lead time than onshore production. Most of the investment required for new fields that would impact supply through the early 1990s has already been made. The incremental costs to complete ongoing offshore ventures are relatively less significant; therefore, current commitments are likely to be completed even if price expectations diminish.

Onshore activity has a shorter decision lead time than deep water offshore ventures. As a result, changes in price can more quickly affect decisions about future onshore activity and have a significant impact on the outlook for onshore production in the near term.

The production outlook developed from the survey for the lower 48 states includes a small amount of gas supplies from tight sands or Devonian shale based only on existing technologies. In a 1980 study, the NPC assessed the future role that unconventional sources could play in the U.S. gas supply picture. The study reported that, with advanced technology, an additional 3.2 TCF per year could be obtained after 15 years at prices of no more than $2.50 per MCF in 1978 dollars ($3.50 per MCF in 1986 dollars). The study also indicated that more than 1 TCF per year of additional gas production could be obtained from Devonian shale and coal seams at these prices. Because large unconventional resources have already been discovered, production from these sources might play a role for natural gas supply similar to the EOR contribution to oil production.

Given the survey price trends, domestic gas production plus available gas imports will be insufficient by the 1990s to maintain gas consumption at historical levels. The gas bubble is expected to end by the late 1980s in the lower price trend and during the first half of the 1990s in the upper price trend. Once the gas bubble ends, in order to balance U.S. natural gas supply and demand, burnertip gas prices will need to rise above the low sulfur residual fuel oil price to reduce potential demand, resulting in fuel switching to residual fuel oil.

DEMAND RESPONSE TO PRICE CHANGES

NPC Survey Results: Effects on Consumption

It is expected that lower oil prices will eventually increase oil demand and stimulate the economy, thus increasing overall energy demand. This is reflected in responses to the NPC survey. Table 29 and Figure 43 show energy consumption by fuels and Table 30 shows energy consumption by sector. In the upper price trend, total energy and oil consumption increase at average rates of 1.1 percent and 0.7 percent per year, respectively, between 1985 and 2000. For the lower price trend, the rates of increase are 1.3 and 1.6 percent per year, respectively. The bulk of the oil consumption increase occurs in the transportation, industrial, and electric utility sectors.

In the lower trend, the oil consumption growth rate is more than double that in the upper trend, for two reasons. First, the transportation sector, which relies almost solely on oil, is stimulated by the low oil prices and the stronger economic activity. As a result, transportation growth in the lower trend is double that in the upper trend. It has been apparent in the past few years that lower fuel prices have resulted in more driving and the purchase of larger automobiles with better performance. A continuation of the trend is anticipated if prices remain low. While a return to the gas-guzzlers of the early 1970s is unlikely, some slowing in the rate of fuel efficiency improvement of the new car fleet can be expected, and average miles per vehicle will be higher than in the upper price trend. In addition, rail and truck traffic will respond to the stronger economy, resulting in a higher growth rate for diesel fuel.

TABLE 29

SURVEY RESPONSE
U.S. ENERGY CONSUMPTION BY FUELS
(Quadrillion BTU Per Year)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Petroleum Liquids	30.9	32.2	33.5	34.3
Natural Gas (Dry)	17.9	18.1	17.8	17.5
Coal	17.5	19.2	22.0	25.3
Nuclear, Hydro, Other	10.3	12.7	13.3	13.5
Total Primary Energy	**76.6**	**82.2**	**86.6**	**90.6**
Lower Price Trend				
Petroleum Liquids	30.9	34.8	37.5	39.4
Natural Gas (Dry)	17.9	17.5	16.0	15.4
Coal	17.5	19.3	22.4	25.3
Nuclear, Hydro, Other	10.3	12.6	13.2	13.4
Total Primary Energy	**76.6**	**84.2**	**89.1**	**93.5**

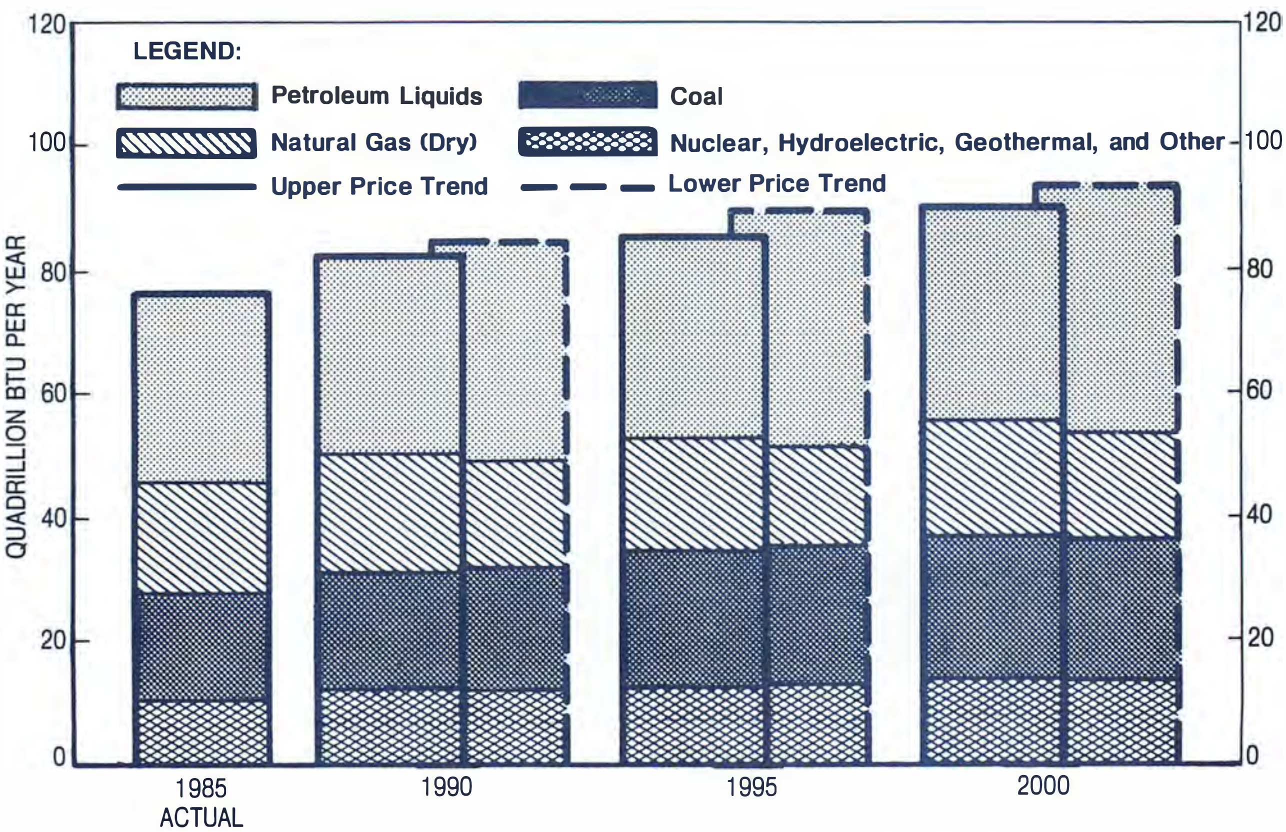


Figure 43. Total U.S. Energy Consumption by Fuels.

In the airline industry, the fare reductions following deregulation have generated much new traffic, and large increases in jet fuel consumption have occurred in recent years. From 1985 to 2000, air traffic is expected to grow with the economy. At the same time, aircraft fleet efficiencies will rise as new, more efficient aircraft are placed in service. Thus, on balance, aviation fuel growth will be moderate. In the lower price trend, however, with fuel costs declining as a percent of operating costs, there is less incentive to replace older aircraft with more fuel-efficient craft. Consequently, aviation fuels growth in the lower price trend could be expected to be somewhat higher than in the upper trend.

The second major impact on oil consumption in the lower trend is caused by fuel substitution in the electric generation and industrial sectors. Natural gas supplies in both trends are inadequate to meet the growth in demand. As a result, dual-fueled plants that normally burn gas would be forced to switch to their alternative fuel—largely fuel oil. In the upper trend, the shortfall occurs mostly after 1995. In the lower trend, the shortfall is greater and occurs by 1990. Most of the substitution takes place in the electric generation sector. Smaller volumes in the industrial sector also switch to oil.

In the residential/commercial sector, total energy growth is higher in the lower price trend in response to the stimulus of lower prices and higher economic expansion. This is in part due to a slackening in conservation efforts. Incentives to replace less energy efficient machinery and building stock are diminished when fuel prices are low. In addition, the higher economic growth of the lower trend can be expected to stimulate commercial activity and thus commercial energy consumption to a greater degree.

In the combined industrial/non-energy sector, the drastic restructuring in the energy-intensive industries appears to be levelling off, and there is the expectation that modest growth is likely in the future. Although substantial energy conservation has been effected in industry since 1973, industry is less sensitive to moderate price swings, and thus energy consumption does not display much variation between the two price trends. Furthermore, because industry is now less energy-intensive, there is greater disparity between industrial energy and GNP growth.

Energy Conservation

Energy conservation is mainly driven by higher prices. It is also influenced by legislation

TABLE 30

SURVEY RESPONSE
U.S. ENERGY CONSUMPTION BY SECTOR
(Quadrillion BTU Per Year)

	Actual 1985	1990	1995	2000
Upper Price Trend				
Residential/Commercial	15.9	16.7	17.3	17.8
Transportation	20.1	20.8	21.4	21.7
Industrial/Non-Energy	22.1	23.7	25.0	26.3
Electric Utility	18.5	21.0	22.9	24.8
Total Energy	**76.6**	**82.2**	**86.6**	**90.6**
Lower Price Trend				
Residential/Commercial	15.9	17.1	17.8	18.5
Transportation	20.1	21.6	22.5	23.5
Industrial/Non-Energy	22.1	24.1	25.4	26.6
Electric Utility	18.5	21.4	23.4	24.9
Total Energy	**76.6**	**84.2**	**89.1**	**93.5**

(e.g., CAFE standards, 55 mile per hour speed limit, building efficiency standards, energy tax credits) as well as by appeals to conserve, but the latter tend to lose effectiveness over time unless supported by higher prices. Conservation in response to market prices takes place over an extended period due to the time needed to replace existing equipment and facilities such as vehicles, machinery, and buildings. Additionally, conservation results from changes in product mix within the manufacturing sector as well as from shifts from energy-intensive manufacturing to services. Conversely, lower market prices for energy reduce the incentives to conserve and the resulting lower levels of conservation will increase demand over time, although existing energy-efficient capital stock will limit the size of this increase.

At present, the United States is still experiencing conservation resulting from the increases in energy prices that occurred in 1973–81. At the same time, the drop in energy prices in 1986 is beginning to stimulate consumption.

The best way to assess the overall trends in energy conservation is to relate energy consumption to changes in economic activity (real GNP) and to changes in real (inflation corrected) energy and oil prices. Table 31 summarizes these changes for key historical periods.

Energy consumption rose in tandem with real GNP at about 4 percent per year during the 1960–73 period, when real energy prices were declining. Thus, over the 1960–73 period, the economy grew 70 percent and energy consumption also grew 70 percent.

After the first oil shock in 1973, energy and oil prices rose sharply and, following the Iranian crisis of 1979, peaked in 1981. This had a pronounced impact on energy consumption during 1973–81 by reducing growth to zero. Economic activity also slowed to a growth of 2.1 percent per year.

TABLE 31

U.S. ENERGY CONSUMPTION, REAL GNP, AND OIL PRICES
(Annual Average Growth Rate, Percent)

	Energy Consumption	Real GNP	Real Oil Price
1960-1973	4.1	3.9	-1.3
1973-1981	0.0	2.1	20.0
1981-1985	0.0	2.5	-10.6
1985-1986	0.0	2.5	-47.2

During the 1981–85 period, energy consumption continued relatively flat, although energy and oil prices began to slide. Economic growth picked up slightly to 2.5 percent per year. However, conservation effects resulting from past increases in energy prices continued to offset any stimulus to higher consumption deriving from lower prices and higher economic growth during this period.

A major factor in halting energy consumption growth after 1973 was conservation induced by higher energy prices. While it may be true that energy consumption was held down somewhat during the early part of the period by appeals to conserve or by legislation, it can also be argued that the real impact of price controls was to reduce the incentives for the automobile driving public and other users to conserve. After 1979, market forces in the form of higher energy prices were primarily responsible for reductions in energy consumption. Overall, between 1973 and 1985, the United States achieved a 30 percent increase in real GNP while energy consumption remained essentially flat.

The slowdown in the growth rate of economic activity was also a factor in holding down energy consumption during the 1973–85 period, but to some extent this slowdown was also induced by higher energy prices. Further, the shift in the composition of GNP away from energy-intensive products and activities to less-intensive products and activities also decreased the nation's energy consumption.

The NPC survey results for energy growth for the 1985–2000 period, by sector, are shown in Table 32. Substantial growth in energy use is expected to occur in all sectors. The greatest increase, about 35 percent, is shown for the electric utility sector. The industrial sector (including feedstocks), which showed a substantial decline between 1973 and 1985 (due in part to the changing industrial mix), increases about by 20 percent. The residential/commercial and the transportation sectors show the greatest sensitivity between the price trends, with energy use increasing relatively modestly for the upper price trend, but rising at substantially higher rates for the lower price trend.

Overall, the survey results reflect a great deal less conservation than in the 1973–85 period, but more conservation than 1960–73. The most significant departure from recent experience is the rise in the industrial sector energy use. This appears to be due to the expectation that the severe decline in the energy-intensive industries from 1973 to 1985 has

TABLE 32

U.S. ENERGY GROWTH BY SECTOR
(Total Percentage Change)

			1985–2000	
	1960–73	1973–85	Lower Price Trend	Upper Price Trend
Industrial (including feedstocks)	+49	-21	+21	+19
Residential/Commercial	+58	-6	+16	+11
Transportation	+76	+8	+18	+9
Electric Utilities	+142	+33	+35	+34
Total Average Change	+70	0	+22	+18

largely run its course and modest growth is now the prospect.

Economic Impacts on Oil and Gas Demand

The energy intensity of the U.S. economy, on average, has been declining for over 50 years (see Figure 45 in Chapter Six)—this trend has persisted through periods of both falling and rising energy prices. As might be expected, this declining trend in energy intensity began a marked acceleration in the early 1970s, corresponding with the first major OPEC price increase. In 1973, total primary energy consumption (excluding biomass) was 74.3 quadrillion BTU and real GNP, measured in 1982 dollars, was $2,744 billion. This corresponded to 27.1 thousand BTU of primary energy consumed per dollar of real GNP. By 1985, real GNP had grown to $3,570 billion, a compound annual growth rate of 2.2 percent over the 12-year period, but total primary energy consumption (excluding biomass) was only 74.0 quadrillion BTU, slightly lower than in 1973. Primary energy consumption per dollar of real GNP was only 20.7 thousand BTU per dollar of real GNP, a 24 percent reduction from 1973. Energy conservation continued in 1986 despite the price decline, with primary energy consumption declining to 20.1 thousand BTU per dollar.

This general decline in energy intensity masks several important underlying trends. First, were it not for the fact that electricity consumption, with its three-to-one primary to end-use energy ratio, was far more resilient to rising prices and sluggish economic growth than other end-use energy consumption, the primary energy to real GNP ratio would have declined at a much faster rate. Second, the composition of the U.S. economy has shifted dramatically away from energy-intensive production over the same time period. This shift has been primarily driven by the combined effect of two distinct trends. First, the goods manufactured by the U.S. economy are less energy-intensive. For example, the typical new car of 1985 may have 1,000 fewer pounds of materials than the typical new car of 1973. This means a reduced demand for steel and many other materials. The second major trend is that a significant share of the increase in U.S. imports has come at the expense of energy-intensive U.S. based industries. Continuing the prior example, not only are there fewer pounds per car, but the entire car and much of its contents may have been manufactured overseas. Thus, while it is correct to attribute sizeable gains in substitution of other factors of production for more expensive energy, a significant component of the decline in energy per unit of GNP over the last decade is the result of compositional changes relating to the structure of the U.S. economy and the changing balance of trade.

The survey responses indicated an expected annual growth rate in real GNP of roughly 2.7 percent for the upper price trend over the 1985–2000 period. For the lower price trend, the survey mean for real GNP growth was not significantly different. The lack of survey difference between trends is deceptive in that respondents fell into two distinct groupings. One group considered low oil prices to be a stimulus to economic growth, while the other group regarded slow economic growth to be a reason for low oil prices.

Based on composite survey results, a gradual slowing of the average growth in the economy was indicated—from 2.9 percent for 1985–90, to 2.7 percent for 1990–95, to 2.6 percent for 1995 to 2000. While short-term economic growth prospects are principally concerned with the demand-side effects, long-term forecasts are typically supply-side limited. The slowing indicated by the survey appears consistent with expected demographic and productivity trends.

Real economic growth expected by the survey is somewhat stronger than the growth of the 1973–85 period, a period dominated by the "aftershock" effects of two major OPEC price increases. The 2.7 percent average growth projected for the next 15 years is quite low compared with the 3.9 percent growth for the 15 years preceding the first OPEC price shock. This is because the earlier period was characterized not only by lower energy prices, but also by rapid labor-force growth fueled by increased female participation as well as baby-boom entrants in the latter half of the 1960s.

Expected growth in real GNP over the next 15 years can be viewed as the joint contribution of two growth components:

- Growth that stems from increasing the level of utilization of the economy
- Growth that results from increasing the capacity of the economy.

The latter issue is conventionally answered by calculating the expected rate of growth of potential output: the output that would be produced at a relatively low but stable unemployment rate, and at a relatively high but stable rate of capacity utilization. The rate of growth of potential output is determined by the rate of growth of factors of production (principally labor and capital) and the rate of change in the productivity of these factors.

Over the 1985–2000 period, growth in potential GNP is likely to be substantially lower than the 3 to 4 percent range that was typical of the late 1960s and early 1970s. The strong historical growth in potential GNP was mirrored by the performance of actual GNP and similarly, a more modest outlook for future growth in potential GNP acts to limit prospects for real GNP growth.

The strong historical growth was the result of an unusually strong growth in the labor force as the post-war babies reached adulthood and entered the workforce. A further stimulus to workforce growth during this period was an unprecedented growth of female participation in the workforce. The first factor will not be present over the next 15 years and growth in female participation is likely to continue, but at a much slower rate. The net effect is that workforce growth for the 1985–2000 period is likely to be roughly 1 percent lower than for the 1970–85 period.

Since employment growth is strongly influenced by demographic changes, there is usually a reasonable consensus across various forecasts. Growth in labor productivity, a second key determinant of GNP growth, is much more uncertain. It is difficult to estimate, and opinions vary widely. The survey's expected real GNP growth of 2.7 percent implies that real GNP per member of the workforce grows at roughly 1.5 percent for the forecast period—somewhat stronger than the usually sluggish performance of the mid-1970s to the mid-1980s, but well below the growth of the 1950s and 1960s.

The upper price trend shows primary energy consumption growth of 1.1 percent and the lower price trend shows 1.3 percent growth from 1985 to 2000. Mean growth for oil and gas consumption was 0.4 percent for the upper price trend and 0.8 percent for the lower price trend. The lower energy growth rates, as compared with survey expectations of real GNP growth, reflect the lagged effects on capital stock induced by the energy price shocks of the 1970s. Higher energy prices led to redesign of capital stock to accommodate higher energy costs. Since capital stock replacement cycles range upward to 30 years or more, capital stock additions will continue to be more energy efficient than the stock being replaced for many years. This process continues despite the fact that energy prices have declined.

Projected energy-to-GNP growth ratios of less than one probably also reflect the assumption of continued structural shifts toward a less energy-intensive mix of outputs for the economy. Only six industries accounted for over 60 percent of all industrial energy purchases in 1980. These were chemicals; primary metals; refining; stone, clay, and glass; food products; and paper products. Annual output growth for these six industries for 1974–84 is shown in Table 33. Because of no growth in refining and the substantial decline in primary metals, the composite energy-weighted average output growth for these six industries was only 1.3 percent for the 1974–84 period—or only one-half of overall economic growth.

Given the dominance of these industries in terms of industrial energy consumption and given the energy conservation efforts of industry as a whole, it is not surprising that total primary energy and electricity consumed by industry

TABLE 33

KEY ENERGY CONSUMING INDUSTRIES

	Real Output Growth 1974–84 (Percentage Change Per Year)	1980 Purchased Energy (Quadrillion BTU)
Chemicals	3.7	2.72
Primary metals	-2.5	2.28
Refining	0.0	1.18
Stone, clay, and glass	1.8	1.12
Food	2.8	0.95
Paper	2.7	1.28
Six Industries Composite*	**1.3**	**9.53**
Real GNP	2.5	

*Note: Weighted by 1980 Purchased Energy.

declined at an annual rate of 1.7 percent during the 1974–84 period, and that industrial oil and gas consumption declined at a 2.0 percent annual rate.

Two key economic determinants of future oil and gas demands will be the level of real GNP growth and the share of services versus energy-intensive manufacturing in the U.S. economy. The growth and composition of the U.S. economy will be influenced by many factors, including the price of oil and gas that prevails. In general, survey respondents tended to associate lower oil prices with stronger economic growth, and higher prices with weaker growth. However, some survey respondents chose to reverse this causality. This group viewed a weaker economic outlook as depressing oil and gas demands, thereby resulting in lower prices for oil and gas. In fact, some of the companies responding to the survey did not submit estimates for the late 1990s because they could not reconcile the assumptions necessary for concurrent, long-term low prices and low demand.

Many industries that suffered sharp retrenchments as a result of high oil costs and/or a very strong dollar, such as refining and chemicals, are currently showing signs of stabilization or even renewed growth. The steel and aluminum industries might be expected to continue to be pressured from imports, but the extreme declines of the last 10 years may not continue.

Stone, clay, and glass have been generally less susceptible to imports because of the large transportation component in delivered finished goods. This industry is closely tied to the cost of energy and to the level of interest rates. Both factors could provide a reasonably solid growth path, particularly under the lower oil price trend. Chemicals are strongly tied to the cost of energy in that oil and gas serve as raw materials as well as fuels. Lower oil prices could generate strong growth through lower priced chemicals penetrating markets that had been ruled out previously because of high costs.

Total U.S. primary energy consumption declined slightly over the 1973–85 period—a period in which real GNP growth was averaging 2.2 percent per year. As shown in Table 34, the decline in industrial energy consumption was by far the dominant contributor to this decline. The decline in the industrial sector was caused by both a substantially lower energy consumption per unit of output and an extremely sharp decline in industrial output as a share of GNP. Industrial conservation of energy has not run its course because of the very long lags in the capital stock replacement process. It might be argued, however, that this process might begin to see diminishing return effects. It is also likely that the sharp retrenchment in the output level of the energy-intensive sectors is about finished. The extent to which this is true depends on the level of oil and gas prices. The lower oil price trend could sharply boost chemical and refining output, and also provide a stimulus for other energy-intensive sectors.

For a base case projection, it is reasonable to assume that the continued momentum of conservation and GNP composition effects would dampen the growth of total energy consumption as compared with the real growth of the overall economy. The survey results reflect this logic in that energy consumption grows at

TABLE 34

PRIMARY ENERGY CONSUMPTION BY SECTOR
(Quadrillion BTU Per Year)

	Residential/ Commercial	Industrial	Transportation	Total Primary Energy*
1973	24.2	31.5	18.6	74.3
1985	26.8	27.1	20.1	74.0
Increase/Decrease	+2.6	-4.4	+1.5	-0.3

*Electricity losses are distributed proportionately to each sector's electricity consumption and total primary energy does not include biomass.

only 41 percent to 48 percent of the rate of economic growth depending on the price trend assumed. On the margin, however, it is not at all clear that energy consumption, and particularly oil and gas consumption, might not see a leveraged response to changes in levels of industrial activity. If the level of economic output, for some combination of reasons, turned out to be 10 percent higher than expected for the year 2000, it seems very likely that oil and gas demand would increase by more than 10 percent. The reason for this is that oil and gas tend to serve not only a baseload role but also a "swing" role in what is likely to be the fastest growing consuming sector for primary energy—the electric utility industry.

Electricity demands have been extremely resilient to the sharp increases of energy and capital costs and the subsequent pass-through effects on the price of electricity. While non-electric primary energy declined 1.1 percent annually between 1973 and 1985, electricity sales increased at an annual rate of 2.5 percent, which was 114 percent of the annual real GNP growth rate of 2.2 percent over the same period. This occurred despite average nominal increases of 10.1 percent per year in the price of electricity. Forecasts of future electricity demand vary considerably. In testimony at the July 1985 hearing before the Senate Energy and Natural Resources Committee, electricity growth estimates ranged from about 1 percent up to 4 percent. Most estimates of electricity growth, however, ranged around 2.0 percent, which was somewhat lower than the expected real GNP growth rate. The NPC survey shows electricity growth from 1985 to 2000 of 2.2 percent in the upper oil trend and 2.5 percent in the lower oil trend. These correspond to 81 percent and 93 percent of survey real GNP growth.

In many areas of the country, oil and gas serve as the swing fuels in electric generation. This, combined with the facts that all nuclear units currently planned may not be completed for one reason or another, that no new nuclear additions appear likely, and that almost all coal units to be operated in the next 15 years are already known, means that oil and gas demands for the utility sector are very highly leveraged on anticipated load growth. This leverage is suggested by the survey results. A 4.2 percent higher electricity demand for the year 2000 in the lower price trend versus the upper price trend is accompanied by a 12.6 percent greater oil and gas consumption. The actual leverage observed would depend strongly on which regions of the country experienced the strongest increases in electricity demands.

Most central states continue to have a surplus of coal-fired capacity, and this surplus is likely to persist across a fairly broad range of economic growth and energy price scenarios. Both the East Coast and the West Coast—and the West South Central region—use either oil or gas or both as marginal fuels. Stronger than expected load growth in these regions could result in a very sharp increase in oil and gas demands, because capacity additions would probably be combustion turbines, thereby further adding to oil and gas demands. In addition, oil and gas fired plants currently scheduled to be retired could be retained in service.

It should also be mentioned that this leveraged demand for electric utility oil and gas could be evidenced on the downside as well. If national electricity growth resulted in 10 percent lower than expected system demand in the year 2000, the percentage decline in utility oil and gas demand would be much sharper, particularly for the upper oil price trend.

Alternative Energy Sources and Fuel Substitution

One of the key themes in U.S. energy markets in the last 35 years has been a steady shift in the pattern and composition of fuel use. The shifts have occurred primarily as a result of economic and geopolitical events. The relative cost of fuels and sources of energy have been important factors. The two episodes of energy inflation in the 1970s have been pivotal in creating these changes.

Fuels other than petroleum and natural gas represent major potential future sources of energy for America. Coal is the most important, but other alternatives that can make significant contributions include nuclear energy, hydro, and to a lesser extent solar, geothermal, and biomass (including ethanol). Table 35 shows U.S. reserves of coal and uranium.

The predominance of petroleum and natural gas in meeting America's energy needs is a relatively recent phenomenon. It was not until 1950 that oil surpassed coal as the major energy source. Natural gas moved into second place in 1958, but yielded to coal in 1986. The energy domination of oil and gas during the past 30 years was primarily due to economic reasons—oil and gas were inexpensive relative to coal—not because the nation's resource base of alternatives was limited. Indeed, as oil and gas prices rose sharply in the 1970s, alternative energy sources became relatively less expensive

TABLE 35

COAL AND URANIUM RESERVE BASES*

	Billions of Short Tons	Billion Barrels of Oil Equivalent	Years of Supply‡
Coal, Recoverable Reserve Base (Beginning of 1985)	283	1,075	319

	Millions of Pounds†	Billion Barrels of Oil Equivalent	Years of Supply‡
Uranium Reserve Base (Beginning of 1985)			
Reasonable Assured	359	12	80
Estimated Additional	1,318	45	
Speculative	1,040	36–1,800§	50–2,500§

*DOE/EIA Annual Energy Review and International Energy Annual, 1985.

†Economically recoverable reserves at $30 per pound.

‡At the 1985 rate of consumption.

§Higher end of range assumes breeder technology.

than oil and gas and their contribution to America's energy supplies increased significantly.

As shown in Table 36, consumption of alternative fuels almost doubled from 1972—the peak year for the oil and gas share of total energy—to 1985. Over this same period, the alternative fuel share of total U.S. energy consumption rose from 22 percent to 36 percent.

Coal dominates the energy contribution of alternative fuels. Its share of alternative commercial energy supplies (excluding firewood) was just over 70 percent in 1985, four times nuclear energy and six times hydroelectric generation. As technology advances in the future, alcohols, solar, and geothermal may play greater roles—particularly in localized areas of the country where their resource bases are appropriate and the costs of conventional fuels are relatively high.

U.S. coal production in 1985 was about 886 million short tons, with approximately 90 percent of this being anthracite and bituminous coal. Current U.S. coal reserves are estimated at 283,000 million short tons. At current levels of production, these coal reserves will last over 300 years.

Over 80 percent of coal consumption currently is for electric generation. The NPC survey shows total coal consumption increasing about 50 percent from 1985 to the year 2000 for both price trends, about the same rate as in the past 15 years. Electric generation will account for

TABLE 36

U.S. ENERGY CONSUMPTION BY SOURCE: 1972 AND 1985

	1972		1985	
	Quadrillion BTU	%	Quadrillion BTU	%
Alternative Fuels	15	22	28	36
Petroleum & Natural Gas	56	78	49	64
Total	**71**	**100**	**77**	**100**

nearly all of the increased volume. Despite the fact that coal prices have been well below those of either residual fuel oil or natural gas (see Table 37), the shift to coal usage in utilities and large industrial facilities has been slowed, partly because of the considerably greater investments required to store, handle, and burn coal (including treatment to meet environmental standards) relative to residual fuel oil and natural gas. In addition, there is reluctance to commit large capital investment to coal-fired base-load capacity additions beyond those already planned and under construction while there is surplus generating capacity.

TABLE 37

COST OF FOSSIL FUELS DELIVERED TO STEAM ELECTRIC PLANTS (Dollars Per Million BTU)

	Coal	Residual Fuel Oil	Natural Gas
1975	0.81	2.00	0.75
1980	1.35	4.27	2.20
1985	1.65	4.24	3.43
October 1986	1.59	2.38	2.36

Nuclear power has been one of the fastest growing sources of alternative energy over the past 15 years. In spite of the fact that no new nuclear plants have been ordered since 1978 and many have been cancelled or deferred, the completion of those under construction will increase nuclear energy output about 50 percent by the mid-1990s according to the survey responses under both price trends. This assumes the completion of approximately 30,000 megawatts of generating capacity between 1985 and 1995, and total U.S. nuclear capacity operating at an average capacity factor of nearly 60 percent by 1995. Nuclear's share of total electricity output is now about equal to that of oil and gas (see Table 38) and will be second only to coal for the balance of the century.

Given the NPC oil price trends, nuclear usage could be lower if new nuclear plants that are near completion are not finished or if existing plants are shut down prior to the end of their useful lives. Coal usage could be lower if new construction is delayed or because of environmental constraints. If these situations occur, oil will most likely be the fuel substituted, creating a larger demand for imports.

Electricity generated by hydropower accounts for about 10 percent of total electricity generation and 4 percent of total U.S. energy. Its share is expected to continue at about 4 percent to the year 2000 in both price trends.

No major increases in hydroelectric power generation are anticipated. Current installed hydroelectric generating capacity is some 90,000 megawatt (MW) out of total U.S. generating capacity of 654,000 MW as of the end of 1985. Over the next decade, additions to hydroelectric capacity are not expected to exceed about 4,000 MW. The small size of the future increase in capacity is limited by the number of available sites that are both politically and technically feasible.

Geothermal energy accounts for less than one-half of one percent of total electric generation. A number of sites in the western states are being developed, and there are other areas that have potential for development. However, geothermal energy will not become a significant factor in the U.S. energy mix in this century.

Solar energy contributes a very small proportion of America's energy supplies. The removal of federal tax credits at the end of 1985 and the recent decline in oil and gas prices have considerably dampened enthusiasm for solar energy.

The consumption of wood, wastes (landfill methane, agriculture wastes, and refuse-derived fuels), and alcohol fuels totalled an estimated 2.8 quadrillion BTU in 1985. Wood was by far the most important. The technology exists for expanding supplies of agriculturally derived fuels and other forms of biomass energy. At current competing energy price levels, however, these biomass energy forms are not competitive without significant governmental support.

Table 39 shows the shares of each energy source for the upper and lower price trends.

INTERNATIONAL EFFECTS OF ALTERNATIVE ENERGY ON OIL CONSUMPTION

It is important to consider oil as a world commodity, and while what is done in the United States is significant, it will not be the deciding factor in determining world oil prices or world oil demand. In fact, most studies of future oil consumption indicate that much of the growth of oil consumption will occur in the developing and oil-producing nations.

Use of petroleum can be divided into two categories—light oil for transportation, and

TABLE 38

NET GENERATION OF ELECTRICITY BY ENERGY SOURCE
(Terawatt Hours)

	Coal	Oil & Gas	Nuclear	Hydro	Geothermal & Other	Total
1970	704	557	22	248	1	1,532
1975	853	589	173	300	3	1,918
1980	1,162	592	251	276	6	2,287
1985	1,402	392	384	281	1	2,460

heavy or residual fuel oil for industrial use and electrical power generation. The potential alternatives are different, and thus the degree of substitution has been very different in the last decade. Coal, natural gas, nuclear power, and water power are significant competitors for industrial power. There are only a few viable alternatives for transportation fuels, such as natural gas (either compressed or liquefied), propane, ethanol, and methanol.

There are trends toward the use of alternatives for transportation fuels in oil poor nations. Compressed natural gas is an economically attractive fuel where the limited distance between refuelings of 100 miles or less is acceptable. Depending on the part of the world and whether taxes are levied or not, the direct operating cost per mile of a vehicle using compressed natural gas may be from 30 to 75 percent of the cost of using petroleum products. In New Zealand, nearly 10 percent of the vehicle fleet is operating on compressed natural gas.

For longer trips, a liquid fuel is preferred. There have been many studies on the relative

TABLE 39

SURVEY RESPONSE
U.S. CONSUMPTION OF ENERGY BY SOURCE, 1990–2000
(Percentage of Total)

	Coal	Natural Gas	Petroleum	Hydropower	Nuclear	Other*
Upper Price Trend						
1990	24	22	39	4	7	4
1995	25	21	39	4	7	4
2000	28	19	38	4	7	4
Lower Price Trend						
1990	23	21	41	4	7	4
1995	25	18	42	4	7	4
2000	27	16	42	4	7	4

*Geothermal, solar, wind, and wood.

economics of alternative liquid transportation fuels. Most confirm that the lowest cost alternative liquid fuel would be methanol produced from wellhead natural gas. Ethanol is significantly more expensive, as are the more exotic alternatives.

The South African SASOL program confirms that it is possible to make enough synthetic fuels from coal to maintain the economy. The Brazilian experiment with use of ethanol has demonstrated that it is possible to use a biomass-derived fuel to offset the need to import substantial amounts of oil or petroleum products, even if the price is not competitive with oil at today's prices. New Zealand's natural gas-to-methanol-to-gasoline plants are in the early stages of operation, and demonstrate the fact that there are few unknowns, technically or economically, with these processes. However, they are not competitive at today's oil prices.

There is general agreement that, at some time, low cost crude oil resources will be exhausted and it will be more economic to use alternatives. There is little agreement on when this will be true. It depends on the assumptions made on the relationships between the total costs of using the various alternative fuels, including production, processing, distribution, and combustion.

Oil resources constitute only about 5 percent of the world's fossil energy. World oil exploration induced by the high prices of oil has provided one surprising result: there is a lot of natural gas, at least twice as much on a BTU basis as petroleum, potentially much more.

It is appropriate to view the use of alternatives on a world basis, rather than a U.S. basis, as the countries that lack significant domestic oil resources have strong incentives for use of alternatives that are less important in the United States, at least in the time period of interest to this study. These are the same nations where most oil consumption growth has been expected to occur.

Many of these nations spend a large portion of their foreign earnings to import oil. Since there is no domestic market, natural gas has a very low value at the wellhead in these nations. The problems they face are distribution and conversion of equipment, like electrical generators and boilers, to operate on natural gas.

Several nations, including Malaysia, Thailand, and India, are considering committing resources to the development of the network of pipelines or other facilities needed to transport natural gas to the users. Some oil-poor nations like Argentina and New Zealand already have much of the needed pipeline systems. The use of lower cost domestic resources like natural gas should assist the growth of the economies of those nations, and at the same time could decrease their consumption of petroleum products. While such moves are certain in the long run, the timing is in question. It will depend on the world price of crude oil, as well as the availa-ability of capital for major investments like pipelines, and the time to approve and construct them.

Similar economic incentives apply to the use of coal for boilers and utility power systems. The direct cost per BTU of coal, of course, is much lower than either oil or natural gas. However, the total cost of using coal must include the handling and air quality control equipment. These environmental constraints do not apply in most of the world. Major low cost deposits are being developed (e.g., Colombia), which should lead to increasing international trade in coal, and thus the potential for reduction in the use of petroleum products on a world scale.

SUMMARY

1. Petroleum use is pervasive and in many uses does not have a substitute in the near term.
2. Because the United States is a net importer of energy, especially oil and natural gas, and because the United States has and will continue to import oil and natural gas from the international marketplace, domestic energy prices will continue to be affected by events occuring outside the United States.
3. As a result, after relative price stability between 1933 and 1973, prices have become volatile again, much as they were prior to 1933.
4. Continued price volatility will have a tendency to discourage investment in exploration and development of the petroleum resource base of the United States.
5. If the current low oil and natural gas prices continue, then consumption can be expected to increase steadily while domestic production will decline sharply. These circumstances will result in rapidly growing levels of petroleum imports.
6. Domestic production of both oil and natural gas will decline under both price trends surveyed. In the lower price trend domestic production drops off especially rapidly. It should be remembered that even in the forecasts made in 1985 before

the recent severe price decline, U.S. domestic production was expected to decline gradually, but much less so than in the two price trends used by the NPC survey. The drilling survey demonstrates clearly why this will happen. Under the low prices existing currently, participation rates in drilling activity decline drastically.

7. These lower levels of exploration and drilling activity will inevitably lead to markedly lower levels of reserve additions. This in turn will result in lower production and thus rapidly growing imports.

8. The case for natural gas is different from that for oil. Whereas U.S. dependence on oil can easily grow to very high levels without the need to invest in major new facilities to handle oil imports, the same is not true for natural gas. Low energy prices will discourage investment in all aspects of the natural gas business, including pipelines for imports, resulting in consumption of natural gas being supply limited. This will result, ironically, in even higher oil imports.

9. Under the upper price trend, the call on OPEC production will approach current OPEC capacity prior to the year 2000. This situation develops by the early 1990s in the lower price trend, creating the potential for either another oil price shock or the achievement of long-term cartel pricing of oil by OPEC.

CHAPTER SIX

PHYSICAL FACTORS

INTRODUCTION

This chapter addresses three sets of factors that affect the nation's supply of and demand for oil and natural gas: the size and location of the nation's oil and gas resource base; the technology that exists to avail the nation of this resource base; and the condition of the sector of the oil and gas industry that is being most affected by the recent oil price decline—the oil field service industry.

The absolute amount of oil and gas in place is finite but can only be estimated. A great deal of effort is expended on assessing the location and magnitude of oil and gas resources. Over time, seismic exploration, drilling, experience, and advances in methodology and technology improve the accuracy of these estimates. Changes in production technology and current and expected prices also redefine how much of the resource base is economically recoverable.

Despite the uncertainty, the measures indicate that major U.S. oil reserve additions will occur mostly in frontier and offshore areas. The U.S. onshore natural gas resource base is less developed than the oil resource base, and potential for natural gas reserve additions exists in fields already discovered, as well as in offshore and frontier areas.

In discussing technological developments, one can distinguish between those that allow previously impractical things to be accomplished, and those that reduce costs of existing technologies. Many current technologies were stimulated by the higher oil prices of the 1973–85 period, but are uneconomic at current price levels. The lower prices have reduced the research activities needed to develop new technologies.

Oil and gas companies do little of their own field work. They rely extensively on the specialized companies that comprise the oil field service industry for their exploration, drilling, development, and well maintenance work. The decline in exploration and drilling activity has been particularly damaging to the oil field service industry. There are long-term implications beyond the current regional and sectoral hardships, in terms of the reduced ability of the oil and gas industry to respond rapidly and efficiently to a future increase in demand for exploration and production activities.

PETROLEUM RESOURCE BASE

The domestic petroleum resource base is a key factor in determining the U.S. oil and gas outlook. Whatever can be discovered, developed, and produced in the decades ahead depends on both the amounts that exist and their characteristics.

The purpose of this review of domestic petroleum resources is to provide essential background to the discussion of potential supply. It defines the key terms used in the assessment of petroleum resources, discusses why and to what extent estimates of domestic petroleum resources have changed, and indicates the key implications of these changes for the domestic supply outlook. The discussion is limited to conventional sources of oil and gas, excluding unconventional sources such as oil shale, tar sands, and gas in coal seams.

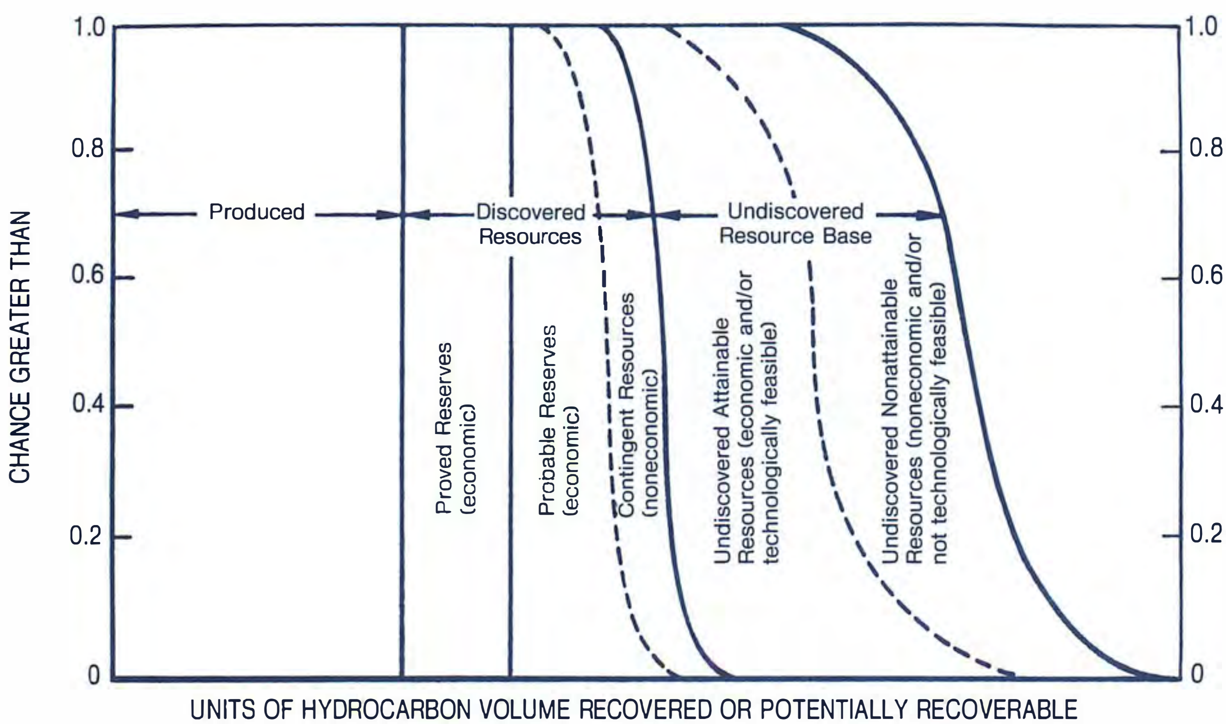
"Petroleum resources" as used in this study represents the quantities of oil and gas believed to be eventually recoverable, by means of known or expected technologies, and not the total volumes in place. Recoverability, and thus availability for human use, is the defining characteristic of a resource. For example, only about one-third of the oil in place in a reservoir is recoverable on average, even with secondary recovery. For most gas reservoirs, approximately two-thirds is usually recoverable. Very large amounts of oil have been estimated to exist in place in the subsurface. A significant portion of these volumes is potentially recoverable, the ultimate amount depending on economics, technology, and basic understanding of reservoirs. However, part of that volume exists in such a dispersed manner that it would not likely be recovered by any currently conceivable economic means.

Resources include both discovered and undiscovered sources of petroleum (Figure 44). "Discovered resources" are all the oil and gas that have been found by drilling, including those resources that have been produced, those that have been found and are or may become economically recoverable (proved and probable reserves), and the theoretically recoverable but currently uneconomic or technologically unattainable (contingent) resources. "Undiscovered resources" are those resources that are yet to be found, whether or not they are currently economically and technologically attainable.

The division of domestic resources among these categories changes continuously. Proved developed reserves are produced. New fields are discovered. Price increases make previously unattainable resources available for supply. Price decreases reduce these proved reserves. Improvements in exploration, development, and production technology make it possible to find and produce resources that previously were economically inaccessible.

The total amount of oil and gas that is theoretically recoverable by means of known and potential technologies is finite but unknown. Any estimate of this amount is inherently uncertain. To convey this uncertainty, resource assessors express their estimates in probabilistic terms.

Over time, the range of uncertainty in resource estimates tends to be reduced. As exploration proceeds, either new fields are discovered or prospects are determined to be nonproducing. Additional production experience results in a better understanding of known reservoirs and their ultimate potential. However, discontinuous changes can increase the range of uncertainty. Sharp price increases, such as those that occurred in 1973–74 and again in 1979–80, may revise the limits of economic feasibility dramatically.



SOURCE: National Research Council, *Offshore Hydrocarbon Resource Estimation: The Mineral Management Service's Methodology, 1986.*

Figure 44. Ultimately Conventially Recoverable Petroleum Resource Base.

The importance of accurate resource estimates to the quality of supply projections and the effect of experience on the estimation of resources can be illustrated by a review of a prior NPC study on domestic oil and gas supply. In the late 1960s, the NPC Committee on Possible Future Petroleum Provinces of the United States conducted a major study on U.S. petroleum potential, the results of which were published in 1971 in a two-volume study entitled *Future Petroleum Provinces of the United States—Their Geology and Potential*. In that study, the Committee estimated that 41 percent of the ultimate recovery of crude oil and 37 percent of the ultimate recovery of natural gas had been discovered and made recoverable by the end of 1970, as shown in Table 40. Half of the crude oil (161 billion barrels) and 63 percent of the natural gas (1,178 TCF) that would ultimately be recovered were estimated to be in fields that had not yet been discovered.

These estimates of domestic resources were subsequently used as the basis for future reserve additions and production by the 1972 NPC Committee on the U.S. Energy Outlook. Its projections of reserve additions for crude oil and natural gas for 1971 to 1985 are summarized in Table 41 and compared to what actually happened during this period.

Actual crude oil reserve additions during this period were 34.7 billion barrels, 52 to 81 percent of the projected amounts. Actual natural gas reserve additions were 195.2 TCF, or 48 to 140 percent of the projected amounts. This difference between projections and actual results occurred despite the fact that the actual drilling rate was higher than the highest rate assumed in the study.

The earlier NPC estimates not only overestimated domestic resource potential relative to finding rate and drilling effort; they also misidentified the primary source of future reserve additions. Future reserve additions were expected to come predominantly from new field discoveries (85 percent of crude oil and 100 percent of natural gas). As discussed in Appendix D, the bulk of reserve additions during the past 15 years—67 percent of crude oil and 40 percent of natural gas—has come from reserve growth in fields discovered prior to 1970. Actual reserve growth from 1970 to 1985 was 83 percent of what the NPC had estimated as ultimate reserve growth for crude oil, while actual new discoveries were only 7 percent of the NPC estimate of ultimate potential.[1]

Although there were some differing views of discovery potential, the NPC estimates were representative of assessments of domestic petroleum resource potential around 1970. Most assessors of the period underestimated reserve growth potential from existing fields. In the intervening 15 years, assessments of U.S. petroleum resource potential have changed substantially. Overall estimates have dropped due to reduction in new discovery potential; however, estimates of reserve growth potential in existing fields have increased.

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[1]Nehring, Richard, "Estimating Reserve Growth: Opportunities and Challenges for Petroleum Resource Assessment." Talk given at American Association of Petroleum Geologists annual convention, San Antonio, TX, May 13, 1984.

TABLE 40

NPC 1970 STUDY ESTIMATES OF THE ULTIMATE RECOVERY OF CRUDE OIL AND NATURAL GAS IN THE UNITED STATES

	Cumulative Production Plus Proved Reserves	Probable Reserves	Future Discoveries	Ultimate Recovery
Crude Oil (Billion Barrels)	132	28	161	321
Natural Gas (Trillion Cubic Feet)	679	No Estimate	1,178	1,857

TABLE 41

NPC 1972 STUDY ESTIMATES OF RESERVE ADDITIONS FOR CRUDE OIL AND NATURAL GAS: 1971–1985 (NPC Projected Ranges and Actual)

	Lower 48 Onshore	Lower 48 Offshore	Alaska	United States
Crude Oil (Billion Barrels)				
Actual	27.4	5.1	2.2	34.7
NPC Range: High	40.4	12.6	13.5	66.5
Low	30.8	5.3	6.8	42.9
Natural Gas (Trillion Cubic Feet)				
Actual	121.2	68.1	5.9	195.2
NPC Range: High	200.5	141.0	64.3	405.8
Low	70.7	48.9	20.0	139.6

In 1981, the USGS published a detailed assessment of the U.S. resource potential,[2] which indicated an expected ultimate potential of 258 billion barrels for oil and 1,541 TCF for natural gas, as shown in Table 42.

Although estimated total potential for both oil and gas dropped around 20 percent from the 1970 NPC assessment, the assessment of the contribution from future discoveries was cut in half. Reserve growth estimates were largely unchanged and events since have shown that they were too low. More than half of the estimates of ultimate reserve growth made by the survey in 1981 have already been converted to reserves. A more recent study in 1984 by the Minerals Management Service[3] indicated that there has been a further substantial reduction in the estimated potential for future discoveries in the federal portion of the offshore, as shown in Table 43.

The difference between resource estimates for these two studies can be attributed to the following factors:

- Differences in evaluation methodology
- Revised economic environment
- Discoveries in intervening years
- Disappointing drilling results in Alaska and the Atlantic.

In preparing their resource estimates, the USGS divided the nation into geologic provinces. Each member of resource appraisal teams, consisting of 6 to 12 geologists, made independent subjective estimates of the ultimate potential for these provinces. These geologists used various methods for estimating ultimate recovery including extrapolation of historical data, areal or volumetric yield analogies, and direct calculation of potential based on individual play or prospect analysis. Estimates by these geologists for key probability parameters were averaged and a probability distribution for each province was determined. In contrast, the Minerals Management Service made a direct calculation of the probability distribution of the ultimate potential for each identified prospect. This approach eliminates the potential contribution from unforeseen prospects and as a consequence would tend to provide conservative resource estimates.

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[2]Dolton et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*. Geological Survey Circular 860, 1981.

[3]Cooke, Larry W., *Estimates of Undiscovered Economically Recoverable Oil and Gas Resources for the Outer Continental Shelf as of July 1984*. Minerals Management Service, U.S. Dept. of Interior OCS Report 85-0112, 1985.

TABLE 42

1981 USGS ESTIMATE OF U.S. RESOURCE POTENTIAL

	Alaska	Lower 48 Onshore	Lower 48 Offshore	Total
Crude Oil (Billion Barrels)				
Cumulative Production	1.9	111.4	7.5	120.8
Proved Reserves	8.9	15.9	3.0	27.8
Probable Reserves	5.1	20.4	1.4	26.9
Future Discoveries	19.1	47.7	15.8	82.6
Total	**35.0**	**195.4**	**27.7**	**258.1**
Natural Gas (Trillion Cubic Feet)				
Cumulative Production	1.8	519.3	56.8	577.9
Proved Reserves	32.0	123.3	36.3	191.6
Probable Reserves	5.6	132.1	39.8	177.5
Future Discoveries	101.2	390.2	102.4	593.8
Total	**140.6**	**1,164.9**	**235.3**	**1,540.8**

TABLE 43

COMPARATIVE ESTIMATES OF FUTURE DISCOVERIES: FEDERAL OFFSHORE

	Crude Oil (Billion Barrels)			Natural Gas (Trillion Cubic Feet)		
	USGS 1981*	MMS† 1984	Difference (Percent)	USGS 1981*	MMS† 1984	Difference (Percent)
Region						
Alaska	12.2	3.3	-73	64.6	13.9	-78
Atlantic	5.4	0.7	-87	23.7	12.3	-48
Gulf of Mexico	6.2	6.0	-3	68.2	59.6	-13
Pacific	3.2	2.2	-31	6.2	4.7	-24
Total	**27.0**	**12.2**	**-55**	**162.7**	**90.5**	**-44**

*USGS volumes are reduced to account for USGS assessment of federal ownership except for Alaska.

†Minerals Management Service.

Revised economic conditions also affected the magnitude of the resource estimates. The USGS estimate was made in 1981 when prices were rising rapidly, while the Minerals Management Service estimate in 1984 used lower real crude oil prices and low projected growth in prices in the future. Lower prices increase the minimum economic size required for development and hence result in a lower estimate of ultimate potential.

Significant discoveries were made in the Pacific and the Gulf of Mexico between the two discovery assessments. These discoveries directly reduce the size of the remaining discovery potential by transferring resources to a different reserve classification. The resource potential was also reduced between the two resource assessments by the disappointing results in drilling in the Bering and Beaufort Seas in Alaska and in the Atlantic.

Because of the use of different methodologies, comparisons of the two studies will not indicate the magnitude of the reduction in resource estimates that occurred between the two studies. However, the last three factors would make a 1986 assessment even lower than a 1984 assessment since the industry is now experiencing lower crude oil prices, and has experienced additional disappointing drilling results in the Bering Sea since 1984.

In addition to the government estimates of petroleum resources, several major oil companies also conduct periodic assessments of domestic petroleum resources. As part of this study, the National Petroleum Council undertook a survey of available industry estimates. The averages of the mean estimates of those companies that have conducted recent assessments are shown in Table 44. The table shows estimates for both future discoveries and probable reserves of crude oil and natural gas made prior to 1981, in 1981, and in 1986.

Table 44 illustrates how resource estimates change over time with additional knowledge and changing circumstances. Industry estimates of the petroleum potential of Alaska were reduced following a disappointing exploratory effort in the early 1980s. Estimates of the petroleum potential of the onshore 48 states have been reduced because of lower price expectations. Favorable exploration results in the offshore 48 states have resulted in an increase in estimated oil potential and a transfer in gas from future discoveries to proved reserves. Industry estimates of reserve growth were reduced because of lower price expectations and transfers from potential to proved reserves.

In several areas, the industry estimates made in 1981 differed significantly from the estimates of the USGS. The industry average was higher than that of the USGS for future discoveries of oil in Alaska. Industry estimates were lower for future discoveries of oil in the lower 48 states offshore and for both oil and gas in the lower 48 states onshore. The industry estimates for offshore reserve growth potential were also lower than those of the USGS. All other estimates were within 20 percent, a difference within the normal margin of error for aggregate resource estimates.

TABLE 44

NPC SURVEY OF RECENT INDUSTRY ESTIMATES OF U.S. RESOURCE POTENTIAL

	Date of Estimate		
	Pre-1981	1981	1986
Future Discoveries			
Crude Oil (Billion Barrels)			
Lower 48 Onshore	20.9	23.6	19.3
Lower 48 Offshore	9.6	11.0	11.7
Alaska	24.3	24.2	12.9
Total	**54.8**	**58.8**	**43.9**
Natural Gas (Trillion Cubic Feet)			
Lower 48 Onshore	216.3	216.3	193.4
Lower 48 Offshore	82.4	82.4	72.0
Alaska	94.9	94.9	55.4
Total	**393.6**	**393.6**	**320.8**
Probable Reserves			
Crude Oil (Billion Barrels)			
Lower 48 Onshore	20.5	20.5	16.5
Lower 48 Offshore	2.0	2.0	1.5
Alaska	4.5	4.5	2.5
Total	**27.0**	**27.0**	**20.5**
Natural Gas (Trillion Cubic Feet)			
Lower 48 Onshore	111.5	110.5	84.0
Lower 48 Offshore	21.5	22.5	27.5
Alaska	5.0	5.0	15.5
Total	**138.0**	**138.0**	**127.0**

The U.S. Geological Survey and the Minerals Management Service of the Department of the Interior are currently preparing a new assessment of oil and gas resources in the United States. Their joint report is expected to be completed early in 1988. Sources within these agencies indicated that assessments of undiscovered oil resources could be reduced from the 1981 USGS estimates by as much as 25 to 50 percent. They likewise indicate reduction in undiscovered gas resources from that reported in 1981, but less than the reduction in oil. With these changes, government estimates of undiscovered resources should be quite similar to industry estimates. While undiscovered resource estimates will likely be reduced, estimates of projected reserve growth will likely increase on the order of 10 to 20 percent.

The changes in the estimate of ultimate recoverable resources over the 1970–86 period are the result of four factors: (1) higher oil and gas prices increasing the economic resource base, which in turn has affected the remaining three factors, (2) the development of different methods of resource assessment, (3) the results of the exploration effort during the 1970–85 period, and (4) the recognition that substantial reserve growth occurs with time in known fields, partially due to the development of new technology.

During the past 15 years, several new methods of petroleum resource assessment have been developed. The basic direction in the development of these new methods has been to move from the abstract and general to the concrete and specific. Early methods of resource assessment either used volumetric methods or historical projections. The basic procedure of the volumetric method was to multiply the sedimentary volume or area of a basin by an average hydrocarbon yield per unit of volume. The most widely used form of historical projection was to project discovery rates per unit of drilling effort. In both cases, the basic units of assessment were statistical abstractions such as average yields or discovery rates.

Newer methods of resource assessment, which can generally be classified as prospect and play methods of assessments, use very concrete units of analysis, specifically, individual prospects and groups of geologically similar prospects (known as plays). Prospect methods attempt to assess the volumes of hydrocarbons that may be found in specific prospects, given the inherent uncertainties in the estimates of each factor determining the prospect volume. Play methods either sum individual prospect assessments or assess a defined, geologically related group of prospects as a group using an analogous or discovered field size distribution.[4]

The strengths of prospect and play methods of resource assessment are that they focus on the basic units of exploration, incorporate explicit consideration of the factors affecting petroleum occurrence, and identify the specific risks associated with a particular exploration effort. The employment of these types of information has greatly increased the knowledge of the characteristics of the discovered resource base and hence the realism of estimates of the undiscovered resource base. The focus of prospect and play methods on the number and sizes of fields and their discovery patterns has been particularly important in this respect. Key findings of recent research are (1) that domestic petroleum resources are highly concentrated in giant fields (100 million or more barrels of oil or its equivalent in natural gas) and large fields (50 million or more barrels), 80 percent of discovered resources being in fields of this size; and (2) that the largest fields in a play tend to be discovered early in the exploration of that play. The implications of these findings are that substantial additions to domestic resources from new discoveries will be made only if more giant and large fields are found, or if production economics of the smaller fields can be improved so that many such fields will be developed.

The third factor affecting assessments of domestic petroleum resources has been the results of the exploration effort in the United States during the past 15 years. These results present a mixed picture of success and disappointment. On the one hand, 200 to 250 significant discoveries (fields of one million barrels or more) have been made every year since the early 1970s, a record of success surpassed only during the peak period of domestic exploration in the 1950s. An average of 2.0 to 2.5 billion barrels of oil and its equivalent in natural gas also were discovered annually in these fields. Several substantial new plays were discovered.

On the other hand, most of the significant discoveries were small (1 to 10 million barrels). The number of large and giant discoveries declined and became increasingly concentrated in frontier areas and federal lands. Between 1975 and 1985, more than 1 billion barrels of oil or its equivalent in natural gas were discovered per play in only six plays—the Barrow Arch trend in Alaska, the Northwest Santa Barbara Channel trend offshore California, the Overthrust Mesozoic play in Utah and Wyoming, the Pliocene trend offshore Louisiana, and both the Pleistocene Shelf and Slope trends offshore Louisiana and Texas. Several frontier areas—the offshore Atlantic, the Gulf of Alaska, and all tested portions of the Bering Sea basins—have proven to be major disappointments. Overall, the amounts being discovered were less than one-third of the amounts being produced.

The fourth factor affecting estimates of domestic petroleum resources has been the experience of substantial reserve growth in known fields over time. Traditionally, this reserve

[4]For a concise description of the various methods of petroleum resource assessment, see Chapter Three in Committee on Offshore Hydrocarbon Resource Estimation Methodology, *Offshore Hydrocarbon Resource Estimation: The Mineral Management Service's Methodology*. Washington, DC: National Academy Press, 1986.

growth was considered to occur from three different sources: (1) extensions—expansions in the known productive areas of fields and reservoirs, (2) new reservoirs in known fields, and (3) secondary recovery—the injection of water or gas to recover oil beyond that produced by primary recovery.

The API/AGA reserve report data series published information on ultimate recovery of oil and gas by year of discovery through 1979, when this publication series was discontinued. Using this data series, various authors, including Root with the USGS,[5] have shown that estimates of ultimate recovery for discoveries in a given year have continued to grow over the 60-year period—1920 to 1979—covered by the API/AGA data. Root also projected that the ultimate recovery for an oil discovery would eventually be 7.6 times the initial estimate, while for a gas discovery it would be 4.0 times the initial estimate.

The phenomenon of prolonged growth after initial field development can be attributed to (1) the additional knowledge acquired in major complex fields, particularly in the highly faulted fields in the Gulf Coast, due to continued development and observation of reservoir performance and new geological/geophysical techniques; and (2) the implementation of new development technology, such as wireline logging devices and their interpretation (petrophysical technology), fracturing technology, waterflooding, and recently EOR technology.

The oil price shocks in 1973 and 1979 improved the economics of applying known technology and permitted even further reserve growth due to the following:

- "Infill" drilling of additional wells between existing wells for better drainage of known reservoirs
- Well stimulation for increased recovery from tight formations
- Additional enhanced oil recovery, whether by thermal, miscible, or chemical recovery methods
- Development of known, but previously subeconomic deposits
- Lower abandonment production levels.

Recent studies by the NPC indicate that there is substantial potential for production from EOR and the development of unconventional gas resources. The development of this potential is dependent upon prices and the state of technology development.

A major problem in estimating probable reserves is the lack of estimates of ultimate recovery by year of discovery in the DOE reserve report data series. It is generally agreed that the DOE captures a larger percentage of the ultimate recovery as proved reserves in the year of discovery than shown by Root's analysis of the API/AGA data series. However, there is disagreement within the industry as to the magnitude of future reserve growth in older fields. According to one school of thought, substantial future reserve growth should occur in these older fields given the proper economic environment, for the following reasons:

1. Additional recovery and unconventional natural gas technology will be developed and will cause significant additional growth in ultimate recovery for discoveries in all prior years.
2. There exists a substantial potential for additional infill development given the proper economic environment. For example, recent analyses of Texas oil fields indicate that an additional 35 billion barrels of conventionally movable oil—the target for infill drilling—remains in already discovered reservoirs. Up to one-half of this oil may be recoverable through infill drilling.[6] A total of about 115 billion barrels of conventionally movable oil is estimated in the United States.[7]
3. Development of new technology and increased understanding of reservoir complexities have been ongoing and there is no reason to believe that there will not be additional developments that will cause future reserve growth.
4. Substantial amounts of gas could be recovered from tight formations (i.e., tight sands and Devonian shale) using unconventional production techniques (i.e., stimulation). Current gas production from tight formations exceeds 1 TCF per year.
5. Currently, improved recovery of gas-in-place occupies a very modest role in the gas reserve addition picture. While there

[5]Dolton et al., *Estimates of Undiscovered Recoverable Conventional Resources of Oil and Gas in the United States*. Geological Survey Circular 860, 1981.

[6]Fisher, William L., and Finley, Robert J., "Texas Still Has Big Hydrocarbon Resource Base." *Oil and Gas Journal*, June 2, 1986.

[7]Lewin and Associates, *Reserve Growth and Future Oil Supplies*. DOE Contract Report DE-AC01-85FE-60603, 1986.

are geological and engineering reasons for this modest role, a major reason is the regulatory constraints mandating wide spacing for gas wells. If such constraints were removed, the rate of gas revisions would increase substantially, although not to the level of relative importance that they have for oil reserve additions.

According to the other school of thought, future reserve growth in older fields will be much smaller than in the past, for the following reasons:

1. It is not reasonable to expect that new enhanced recovery and unconventional natural gas development technology will be implemented, particularly during the remainder of this century.
2. There has been substantial infill development during the past 10 years as a result of the price shocks. Consequently, the remaining potential is smaller or will require higher prices than occurred in the early 1980s; therefore, the contribution of infill drilling will be small during the remainder of this century.

When comparing the forecasts of future probable reserve growth as reported by the USGS in 1981 and as estimated by the NPC resource survey respondents (shown in Table 44), the USGS apparently gives more weight to the hypothesis of future reserve growth than does the industry today. But regardless of the future role of reserve growth, its importance in providing stable oil production over the 1974–85 period is unquestioned; reserve growth accounted for a very substantial part of total additions.

Special Considerations on Natural Gas

The natural gas outlook derived from responses to the NPC survey proceeds from an assumption that the acquisition price for new gas sources will be constrained by the price of residual fuel oil in the large dual-fuel industrial and electric utility boiler markets. Production in the lower 48 states is projected to decline rapidly, and supplemental imported supplies are assumed to be limited to the capacities of current pipeline transportation links. In the survey responses, the role of gas in the U.S. energy supply mix in the later years is constrained to the supply estimated to be available at the assumed price levels.

If greater supplies of gas were available, projected consumption would be higher. Thus if world oil prices were higher than those assumed for the survey or a constraint on the availability of imported oil made higher gas prices practicable, natural gas could satisfy a substantially larger share of projected U.S. energy requirements. This larger share would probably be in the commercial and electric utility sectors. Wellhead prices of $5 to $6 per MCF by the year 2000 would encourage substantial additional gas supplies.

Estimates of the long-term adequacy of U.S. natural gas supply have oscillated severely over the past 20 years. These large oscillations in perception have resulted in part because discussions have focused on a variety of short-term conditions that have then been extrapolated into long-term trends. Many of these short-term conditions were not representative of the fundamental long-term realities of the oil and gas resource base in the lower 48 states.

In 1967, M. King Hubbert presented a paper detailing the substantial declines in new oil field discovery rates in the United States through 1965. He projected a continuing decline in oil discovery rates. By analogy, he extended these trends to natural gas discovery rates as well. However, new oil and gas discoveries have remained relatively constant since the mid-1960s, averaging about 470,000 barrels of oil equivalent per wildcat.

This stabilization has occurred as a result of improved technology and expanded exploration in new provinces or producing horizons. In the 1960s and 1970s, this expanded exploration occurred in the Gulf of Mexico and below 15,000 feet. In the late 1970s, discoveries began to be made in the Rocky Mountains, the deeper waters of the Gulf of Mexico, and the Eastern Gulf of Mexico, both onshore and offshore. Estimates of the undiscovered resources in these regions indicate that it is likely that substantial resources remain to be discovered in these areas. As a result, it is reasonable to expect that continued exploration in these areas should contribute to maintaining discovery rates at current levels for quite a few more years.

Summary

The size of the resource base, although critical to estimates of future supply, is not the only resource-related factor affecting supply. During the past decade, growing appreciation of and concern for the economic characteristics of the domestic resource potential have evolved. This appreciation could be summed up in the conclusion that the United States has few low cost oil and gas resources yet to be discovered and developed. The remaining petroleum resources are predominantly medium to high cost resources. Many factors point to this conclusion. New discoveries onshore are increasingly small fields, few of which have excellent producing characteristics or high recoveries per well. The large and giant discoveries, which have historically provided low cost resources, are being made in high cost environments such as the deep water offshore, Arctic, and deep (below 15,000 feet) reservoirs. However, the experience of the past decade, while indicating most remaining fields to be small, indicates the smaller fields to be numerous. Reserve growth potential, though substantial, ranges from the moderate cost resources added by infill drilling to some high cost sources, such as the more exotic enhanced oil recovery operations. Converting domestic petroleum resource potential into domestic oil and gas supply thus depends on the future price of oil and gas. In short, although the oil and gas resource base of the United States is economically marginal in that most of it is convertible to reserves only in relatively small increments and mainly from high cost frontier areas, it is at the same time substantial in size and could stabilize reserves if pursued aggressively.

TECHNOLOGICAL ADVANCES

In any discussion of improved technology in oil and gas exploration, production, or utilization, there are two aspects to be considered. First, there are technologies that may allow things to be done that are presently not practical. Second, there are advances that may improve efficiency or reduce costs in more conventional operations. Examples of the first kind are production from frontier areas (Arctic or deep offshore) or the development of synthetic fuels. Examples of the second are improved seismic techniques, infill drilling, EOR methods, or more efficient refining or end-use technologies.

Whatever the technology being discussed, economics should never be far from center stage. The United States is a high cost producer of oil compared to many other parts of the world, and especially as compared to the Middle East (see Chapter Eight). New technology, to have an impact, must be competitive in the prevailing price environment. Dramatic increases in oil and gas prices tend to generate an unjustifiable degree of optimism—a feeling that future price increases will carry the cost of the technological improvement. Sharp price decreases tend to produce a reverse effect—a tendency to feel that the industry cannot afford anything new. The truth lies somewhere between these two.

In oil and gas extraction, technological change and the ability to deploy new technology are evolutionary processes. At any given time, a series of technological improvements will be in various stages from conceptualization through full commercial application. It generally takes many years to move all the way through this process. The impact of new technology tends, therefore, to be felt rather slowly.

Exploration

The ultimate test of the presence of an oil or gas reservoir is to drill an exploratory well, but a great deal of technology is brought to bear on the problem before this stage is reached. Prior to actual drilling, seismic prospecting has been, and will remain, the primary technique for obtaining a picture of what the subsurface structures may look like.

Seismic methods have been in use for a long time. The basic principle is to generate a source of acoustic waves that travel downward and are reflected from the various subsurface strata. An array of detectors on the surface, or sometimes in a borehole, is used to record the pattern of reflections. Using mathematical models of how the reflection process takes place, the raw data are translated into a cross section or map of the subsurface. The geophysicist looks for patterns indicating structures that may trap oil and gas. The mathematical manipulation of seismic data is extremely complex and was revolutionized, beginning in the 1950s, by the advent of cost effective digital computers. The ability to handle larger and larger data sets and to perform increasingly sophisticated calculations in a reasonable time has continually improved as the state of the art in computers has advanced.

Any new exploration technique has to work against the handicap that new reservoirs are likely to be smaller and harder to find. Improved technology may be necessary just to find these reserves in a cost effective way.

Drilling and Production

In the drilling and production area, most work on new technologies tends to be focused on frontier areas. Within the United States, this means Alaska and the Outer Continental Shelf. These areas are judged to have most of the remaining potential for very large discoveries. This is in no sense a new realization. The industry was already moving in this direction by the late 1960s.

Offshore

The proportion of U.S. oil production coming from offshore areas has increased from around 2 percent in 1954 to 14 percent in 1985. However, the ratio has been rather constant (between 13 and 18 percent) since 1968. For natural gas, the contribution from offshore has increased steadily from 0.8 percent in 1954, to 5 percent in 1964, 20 percent in 1974, and 29 percent in 1984.

There has been a progression toward drilling and production in deeper waters throughout the history of the offshore oil industry. For drilling, this has been particularly dramatic. Exploratory wells have now been drilled in almost 7,000 feet of water. This kind of offshore drilling is very expensive. The average U.S. offshore well has always been more expensive than its onshore counterpart. The difference has grown as offshore exploration has moved into deeper waters. In 1984, the average offshore well cost almost six times as much to drill as the average onshore well, up from only 2.5 times as expensive in 1953.

The overall effect of technical evolution in drilling has been to make offshore drilling practical in places where it once was not, and to significantly improve the efficiency of the operation, especially in difficult locations. Technical limitations on the ability to drill are not much of a factor in determining the outlook for future supplies. Further improvements in efficiency would help to control costs and thereby reduce the risk associated with exploratory drilling. However, most of the cost of new offshore production is associated with the development rather than the exploratory phase.

Most conventional production platforms are fixed structures anchored by piles driven into the seabed. A platform in very deep water must be very large, and hence very heavy, in order to support its own weight and the weight of topside equipment. In addition, it must be able to withstand forces generated by the most severe tides, wind, and waves likely to be encountered in the area during its productive lifetime. In the Gulf Coast area, for instance, this means that it must be able to stand up to hurricane conditions. These considerations all combine to make fixed platforms for deep offshore production very expensive.

The latest new concepts in deepwater production platforms, compliant structures that move with wave forces, have been put into actual practice. One example is a guyed tower installed in 1983 offshore the Gulf Coast in 1,000 feet of water. The guyed tower uses a relatively lightweight central tower, anchored to seabed pilings, but relies for most of its resistance to wave action on guy lines, which link the tower to widely spaced seabed anchors. The other active compliant platform is a tension leg design in the Hutton field in the North Sea. A tension leg platform is a floating structure that is connected to anchors fixed in the seabed.

Recently there has been a considerable amount of interest in floating production systems that do not involve any kind of permanent production platform. The first such schemes were introduced as a way to get production on stream earlier and to generate some quick cash flow to help finance a full scale development. Floating production systems are now considered as options for the permanent production of smaller scale fields, where reserves may not justify the expense of a more expensive fixed installation. So far, the deepest water that such a system has been installed in is around 600 feet, offshore Brazil.

An additional advantage of a floating early production system is that it allows an opportunity for a more detailed estimation of what the reserves really are. This can be critical for making the correct investment decision for a very deep water prospect. Operators tend to be very cautious in developing deep offshore fields because of the expense and uncertainty involved. It has been estimated that it may take \$40 to \$80 million to develop a Gulf Coast field in 300 feet of water. Roughly 50 percent of this would be for exploration and lease bonuses, and the other 50 percent would be the cost of development. The same field in 1,200 feet of water may cost over \$500 million. More significant is the fact that 80 percent of this would be development costs. Thus, an operator planning to develop the deeper water prospect may be faced with spending 10 times as much money to do so. Caution is understandable. Early production systems can provide the information needed before making such a large commitment. At the end of 1985, there were more than 20 floating early production systems in operation worldwide.

Another concept that has gained widespread acceptance is the idea of subsea production systems, where subsea wellheads are connected to either a floating production system or to a satellite platform located nearby. Because of the lower cost, subsea installations have been used to develop smaller reserves, which might otherwise have been uneconomic. They can, in principle, be installed in an unlimited water depth. The deepest operating example is in approximately 2,500 feet of water offshore Spain.

There are some 170 subsea installations in operation worldwide.

Summarizing, there has been a continuing trend toward a greater proportion of production coming from offshore. This is expected to continue. There has been a rapid extension of drilling to very deep waters, although it remains expensive relative to more conventional operations. It is much more expensive, in general, to develop deep offshore reserves than it is to discover them. Although technological improvements related to the installation of floating production systems or subsea wells may improve the economics of this kind of operation, deep offshore production will remain high cost. Only the largest prospects, or those close enough to existing production to be operated as a satellite field, will be developed. This will limit the overall level of production that can be obtained from the deep offshore areas.

Arctic

Prudhoe Bay illustrates several things about oil and gas production from the Arctic. It took a very large resource to justify the cost of constructing a pipeline to move the production to a year-round ice-free marine terminal and then to market. Several nearby smaller fields have now been brought onstream, but this was possible only because the pipeline already existed. There are currently a number of other known fields, especially in the Canadian Arctic, which have not been brought to market because of the costs of transportation. The severe environment and the distance from major markets combine to make Arctic exploration and production very expensive. It has been estimated that a well that costs $1.5 to $3 million to drill in the Gulf of Mexico will cost $40 to $50 million in the Beaufort Sea.

A great deal of ingenuity has been and is being used to overcome limitations posed by the remoteness and severity of the Arctic. Many of the most attractive prospects are offshore in areas that are ice bound for much of the year. Drilling in shallow waters can be done from gravel islands or islands constructed from spray ice. The first production from a gravel island is scheduled to begin in 1987, but this will be in only 10 feet of water, and the limit appears to be about 50 feet. Ice islands are limited to about 65 feet of water. Getting further offshore will require drilling vessels that are able to withstand floating ice for a significant part of the year. Extending the drilling season to at least six months is a key to reducing costs. These rigs will have to be built to withstand stresses from the ice. They will require icebreaking support vessels.

Even this will not solve the problem of producing the reserves once they are identified. An offshore prospect may have to be produced from subsea wellheads and transported to shore by under-the-ice pipelines. Transport to market will require tie-ins to the existing Trans-Alaska pipeline, or a completely new line, depending on the location of the resource. The idea of using icebreaking tankers for transport from some locations, particularly in Canada, has been considered.

None of this will ever be cheap. An offshore reserve in areas subject to pack ice will probably have to be in the 1 billion barrel class to justify development, or there will have to be a cluster of smaller prospects that can be codeveloped. From most parts of the Arctic, any production will require significant new technology. The technology itself, however, will not fully offset the high cost—it will merely make production feasible.

Deep and Unconventional Gas

Some of the best gas prospects may be very deep. Wells have been drilled and completed deeper than 30,000 feet. Improvements in drilling methods have made deep drilling more routine. They do not appear, however, to have made it any cheaper relative to wells of more "normal" depth. The high costs always have restricted deep drilling. Wells drilled deeper than 15,000 feet have historically accounted for less than 2 percent of the U.S. total in any given year, and there has been no upward trend. Deep gas seems certain to remain relatively expensive unless a major technical breakthrough in deep drilling is developed.

The NPC published an extensive study of unconventional gas resources in 1980, detailing the resource potential of the various sources and estimating the possible impact of advanced technology. The conclusions indicate that advanced technologies will make a major contribution only at a relatively high price level. First, the increase in conventional and unconventional supplies will come from more widespread use of existing technologies in response to higher prices. The expected adequacy of these supplies will most likely restrict efforts to develop the new technologies needed to produce additional unconventional gas.

Additional Oil Recovery

Through 1984, some 488 billion barrels of oil had been discovered in-place in the United States. Through 1984, cumulative production had amounted to 136 billion barrels and proved reserves stood at 28 billion barrels. Based on existing recovery techniques and existing level of development, ultimate recovery amounted to about 164 billion, or nearly 34 percent, of the in-place known oil resources. Of the remaining in-place oil volumes of 324 billion barrels, about 35 percent is estimated to be movable by conventional secondary techniques and 65 percent is residual, requiring enhanced or tertiary techniques for recovery.

The remaining movable oil is a target for extended conventional recovery—chiefly infill drilling. No detailed estimates have been made on what increments of the resource can be recovered at specific prices. Without question, this part of the resource has been the major source of reserve additions in recent years. Of the 12.6 billion barrels of reserve growth additions from 1979 through 1984, 10 percent came from new pool discoveries, a comparable amount came from tertiary production, and the balance—about 10.7 billion barrels—came from infill and extention recovery of movable oil. Given the substantial size of the target and the contributions to reserve additions in recent years, additional recovery of movable oil, at appropriate price levels, can be significant.

As to tertiary recovery, the NPC produced a comprehensive report on EOR in 1984. The report considered in great detail the current status of enhanced recovery methods and evaluated their possible contributions to the supply picture, including the benefits to be expected from advanced technology. All of the recovery methods—thermal, miscible flooding, and chemical flooding—are in current use, but only thermal, represented primarily by steam flooding in California, has yet made much of a contribution. Enhanced recovery currently accounts for somewhat less than 7 percent of domestic production, and three-quarters of that comes from steam. Most of the rest comes from carbon dioxide miscible flooding, which is expected to increase its share in the next several years as a result of many large scale floods that are in the early stages of their operating lifetime. Chemical flooding, except for the use of polymers, lags behind and has proven complex and hard to predict and control.

Current U.S. proved crude oil reserves are 28 billion barrels. The NPC estimated that EOR using current technology could add 15 billion barrels to this total. Advances in EOR technology could add an additional 13 billion barrels. Price was considered to be a major factor that would determine future levels of EOR activity. The NPC did not evaluate an advanced technology option for oil prices below $30 per barrel (1983 dollars). It was assumed that below $30 per barrel, research in advanced EOR would be greatly reduced or eliminated. The recent price decreases have led to substantial cutbacks in the amount of research being conducted on enhanced recovery processes. This will postpone the development of some of the more complex methods. Even at $30 per barrel, the NPC assumed that the advanced technology options would not be fully available until 1995. This would probably now be considered too optimistic.

The estimated producing rates from enhanced recovery methods, even in the most optimistic scenario of $50 per barrel (1983 dollars), are not anticipated to supply more than some 1.8 MMB/D. At $30 per barrel, EOR production reaches a peak of only 1.2 MMB/D in the late 1990s. At $20 per barrel, EOR production peaks at 750 MB/D in 1992 and declines thereafter. See Chapter Five for a discussion of the Lewin and Associates estimates of potential EOR production based on the NPC methodology.

Refining

In general, the refining industry uses highly efficient, modern technology. Refiners depend upon processes that have evolved over the last 20 to 40 years and are well established and understood. There have been few revolutionary technologies; the character of the industry is to undergo slow and long-term changes. These changes are usually caused by such factors as consumer preferences, increasing costs, and/or government regulations. There are no technical improvements on the horizon that will improve refining efficiencies to the point that crude oil demand is reduced significantly. However, there will continue to be a series of small improvements in catalysis and process optimization that will be applied to the industry to keep it vital and competitive. On the other side of the ledger, increasing environmental impacts on the refining industry will offset some of these improvements in efficiency.

The NPC has estimated that a reduction in motor gasoline vapor pressure of one pound per square inch would reduce gasoline manufacturing capability about 200 MB/D and increase operating costs about $1 billion—about 1¢ per gallon of gasoline produced. Reducing the benzene content of gasoline could require investments of $4 billion or more and add 2 to 3¢ per gallon to gasoline manufacturing costs.

Conservation

In the short term, conservation in response to higher prices primarily occurs because of reduced discretionary consumption. In the longer term, high priced energy leads to the development of technologies that produce greater end-use efficiencies. These occur with a time lag due to the slow turnover in energy-using equipment.

The long-term trend toward greater efficiency, as measured in BTUs per dollar of GNP, was given tremendous stimulus by the oil price shocks of the 1970s (see Figure 45). Total U.S. energy use in 1985 was roughly the same as in 1973, despite a substantially higher GNP. It has been estimated that 1985 consumption would have been 24 percent higher had it not been for improvements in end-use efficiency and changes in the industrial structure. During the 1973–85 time period, U.S. dependence on foreign sources of oil decreased significantly. Reduced energy consumption was the largest contributor to this, since domestic supply remained essentially constant.

When oil and gas use is considered rather than energy use in general, there have been some very significant shifts. Total oil use in the United States decreased by about 4 percent between 1972 and 1985. However, its use in transportation actually went up by 15 percent. This was more than compensated for by a 25 percent decrease in the amount used in the residential, commercial, industrial, and electricity generation sectors. In 1985, 63 percent of oil was used for some form of transportation, versus only 52 percent in 1972.

The dominance of oil by the transportation sector seems likely to increase further with time. The biggest single use is in private automobiles. In world terms, the fuel efficiency of the U.S. automobile fleet remains extremely poor. It has improved slowly from a fleet average of 13.5 miles per gallon in 1972 to 17.9 miles per gallon in 1985. The average new car, however, now delivers around 25 miles per gallon. Future improvements in fuel economy are thus, to some extent, locked into the system. Some of the improvement came about as a result of shifting consumer preferences. These tend to be short lived, however, and could vanish when fuel costs stabilize or come down. Government-mandated fuel efficiency standards could help ensure that improvements will continue. Even though these standards do not apply to heavy trucks, there has also been a substantial improvement in their fuel economy.

The size of the car and truck fleet will most likely continue increasing and so will the total number of miles driven each year. This will tend to offset the improvements in fuel efficiency and tend to hold total fuel demand approximately constant. This can be influenced, however, by consumer perceptions of whether driving is cheap or expensive. The fuel cost decreases of 1986 are sparking an upswing in gasoline demand. If fuel costs remain low, this may have

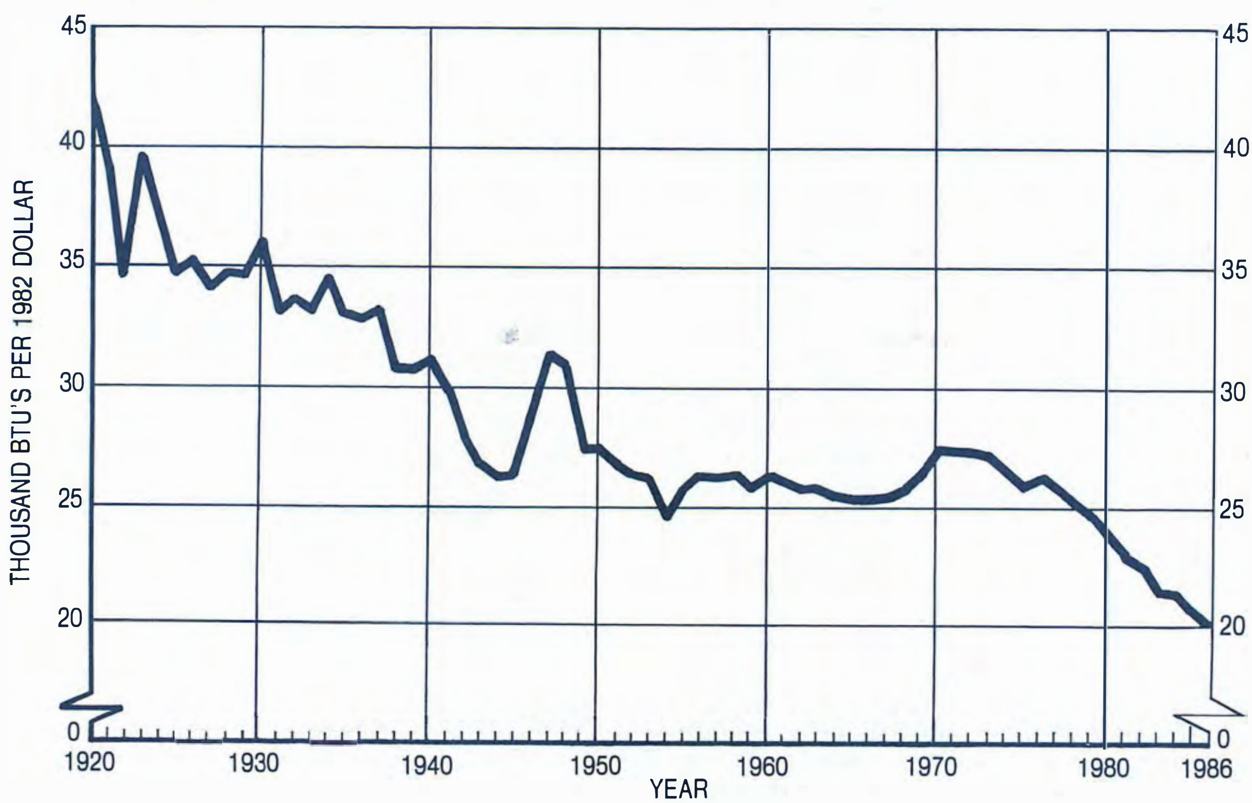

Figure 45. Total U.S. Energy Consumption per GNP Dollar.

a significant cumulative impact on the supply/demand balance.

The other sectors of the economy have, as noted above, actually decreased their usage of oil over the past decade. Some of this could be eroded by the effects of oil price decreases, because of fuel switching for those users who have the alternative. It seems safe to assume, however, that most of the efficiency gains will remain in place.

Technology does play a role in fuel conservation. More sophisticated design of engines and a more widespread use of lightweight materials of construction could significantly reduce fuel consumption in all forms of transportation. Except in aircraft design, however, it is easy to oversell the significance of these factors. In the case of passenger automobiles, proper attention to vehicle design has been, and will be, much more influential. Technology does not preclude significant further gains in efficiency, although it may restrict the size and type of vehicle that could be built to meet a given efficiency level.

A broadly similar conclusion can be reached in regard to energy use in the commercial, residential, and industrial sectors of the economy. Further efficiency gains are possible using known technology. The controlling factor is likely to be the cost of the improvement versus the predicted fuel savings. Efficiency improvements can be expected to slow down in periods when energy is perceived to be cheap.

Alternative Fuels

Another approach on the supply side is the production of "petroleum" from alternative resources, namely coal and oil shale. This route is intriguing because the exploration costs associated with conventional petroleum are avoided; the location, quantity, and quality of these resources are well known. It is a matter of exploiting the resources economically and in an environmentally acceptable manner. However, the costs to exploit these resources to produce petroleum products considerably exceed the price trends utilized in this study.

The United States is fortunate in having at its disposal significant deposits of coal and oil shale, in addition to petroleum and natural gas. While there has been substantial use of coal in electrical power generation, there has been a singular lack of commercial use of coal and oil shale for the production of transportation fuels. The movement to provide a higher level of environmental protection has, in fact, modified the economics of coal-fired power plants, such that the coal market is strongly affected by secondary factors, such as sulfur and ash content.

Unfortunately, with the recent downturn of the petroleum industry, it has been difficult to economically justify the development of conventional petroleum technologies, let alone those associated with alternative fuels. The oil industry has curtailed research and development and demonstration projects related to coal and oil shale. This is not expected to change until the price of energy increases significantly in real terms.

The following is a synopsis of the three main alternative fuel technologies that appear to be closest to commercial viability: coal gasification, coal liquefaction, and oil shale retorting. There are other alternative fuels (e.g., tar sands, geothermal, and solar) that could be addressed here, but are not because of either the small domestic resource (as is the case for tar sands), or the fact that petroleum would not be displaced.

Although direct utilization has some potential in reducing petroleum demand, the major use of petroleum (63 percent) is in transportation. Since transportation fuels are almost exclusively liquids, coal must be "converted" from its solid form to be used in the existing infrastructure. There are two routes to convert coal into fluid fuels—gasification and liquefaction. Both have been in development since the 1920s, and generally involve rather straightforward processes with reasonably understood chemistry. In gasification, the coal matrix is partially oxidized at elevated temperatures to produce a mixture of carbon oxides and hydrogen. After the impurities have been removed, this mixture can be further processed into transportation fuels. In liquefaction, on the other hand, hydrogen is added to the hydrogen deficient coal matrix under high pressures and moderately high temperatures to produce a synthetic crude oil, which can be processed in conventional refineries. However, the resulting liquid is still hydrogen deficient and requires significant upgrading to produce transportation fuels. Several companies, as well as the Department of Energy, have actively developed different processes.

The intensive effort over the last 15 years to produce substitute fuels from coal has shown that there are still significant technical and economic problems that must be solved before coal conversion will be commercial.

The essential technical issues in all gasification processes are associated with the coal gasification unit. The downstream processes of a commercial facility (e.g., gas cleanup and syngas conversion) have been adequately demonstrated and do not present significant technical limitations to the application of gasification. For example, carbon monoxide and hydrogen produced from the gasification process are currently being converted into both gasoline and methanol commercially. On the other hand, the commercial readiness of the different gasifier designs varies considerably.

The liquefaction technical issues are associated with downstream processing and are mostly mechanical in nature (high pressure letdown valves, solids separation, pumping of very viscous slurries). Liquefaction processes currently require high pressures above 2,000 pounds per square inch and elevated temperatures. Presently, coal liquefaction is more expensive than gasification for the production of transportation fuels. The objective of ongoing research is to develop a low pressure (i.e., lower capital requirements), high efficiency (lower production costs) process. This must be done before liquefaction will be able to compete economically with conventional petroleum.

Western oil shale also represents a huge domestic resource—a production potential of 625 billion barrels—and could significantly impact the supply of petroleum if exploited properly. Moreover, because of the lower production costs, oil shale will probably be the first source of substantial quantities of synthetic crude oil. Oil shale is neither a shale nor does it contain oil. It is made up of fine particles of marlstone held together by organic material called kerogen. The kerogen decomposes upon heating to 70 percent liquids, 15 percent gases, and 15 percent coke. The decomposition requires large inputs of heat. With the organic matter removed, the remaining rock loses its cohesive strength and is easily crushed.

All processes for recovering shale oil start with the thermal decomposition of the kerogen, followed by the separation of the organic material from the inorganic solids. There are five reasonably well-developed schemes for above-ground retorting of Western oil shale. All five need further development and/or demonstration on a larger scale; none can be considered commercially proven.

The major problems with all oil shale retorting are environmental and geographical. Environmentally, the vast quantities of spent shale from surface retorts, 160,000 tons for each 100,000 barrels of oil, will need to be disposed of in an acceptable manner. Whereas the raw shale is tough, the spent shale is friable and dusts easily. Large amounts of water will be required to compact the shale and assure plant growth in it. Leaching of alkaline components and heavy metals is also a concern. The 50 percent volumetric expansion after retorting eliminates storage in the empty mines as a solution. Along with the long-term storage of spent shale, other environmental problems will also have to be addressed, including water availability in the Colorado-Utah area, dust control in the mining and crushing operations, and low level hydrocarbon emissions from the plant. Each of these areas will have to be addressed to the satisfaction of all parties.

Geographically, the Western oil shale reserves are located in areas that are remote, largely uninhabited, and devoid of natural water supplies. The development of a large scale oil shale mining and retorting facility will require the expenditure of large amounts of capital for building water transport and shale oil transport via pipelines, and new towns and roads. This peripheral development raises the cost of the oil, thus affecting the economic viability of the project. Thus, real petroleum prices will have to be high before major corporations will undertake the risk involved in developing the shale resources at a level that will supplement meaningful quantities of petroleum-based fuels.

Summarizing, there are several oil shale retorting technologies that appear ready for commercialization, but they are all capital intensive and produce crude shale oil at a higher cost than conventional crude oil. It is unlikely that a large scale commercial industry will be viable in the next 5 to 15 years, especially with the low level of crude oil prices.

There currently exists a satisfactory level of development of alternative coal and oil shale technologies that could be used to provide substantial quantities of petroleum substitutes. The use of coal gasification, coal liquefaction, and oil shale retorting are long-term solutions that will depend on the establishment of economic incentives in the form of escalating real crude oil prices, which can justify the higher capital and operating costs for the commercial exploitation of these technologies.

Summary

It is difficult to envision new technologies impacting the supply of and demand for oil and gas much before the end of this century. Current exploration and production technology was spawned by 13 years of favorable oil prices and the prospect of continuing price growth. These technologies permitted the development and delivery of production from Alaska and deep offshore waters and the economic development of smaller and deeper oil and gas reserves. Many of these technologies are uneconomic at today's depressed prices, and if these prices prevail for an extended period of time, new lower cost technologies will be required. But this takes time, and the low prices themselves have significantly reduced current research and development activities.

Energy efficient technologies spawned by the higher oil prices will not go away overnight. Even if prices remain low for an extended period, there is little incentive to revert to less efficient capital goods. Even if new fuel-efficient end-use technologies emerge, the long lead time to construct new plants to utilize them would delay the benefits until the late 1990s.

IMPACTS OF RECENT PRICE DECLINES ON PETROLEUM SERVICE AND SUPPLY SECTORS

The oil and gas exploration and production industry is made up of thousands of producers, manufacturers, suppliers, and service contractors. Oil and gas companies rely extensively on specialized contractors for their exploration, development, and well completion and maintenance work. While the recent price increases and rapid decline have affected all segments of the petroleum industry, it has been particularly difficult for the companies that compose the oil field service and supply sectors, their financiers, and their host communities. These sectors will be slow to respond to a sharp upturn in demand because of the loss of professional and skilled personnel, the deteriorating rig fleet, the loss of manufacturing capacity, and the inability to finance new investments. If low oil prices persist, the response time of the service and supply industry will lag even more.

Services

Exploration begins with geological and geophysical work and continues through the drilling and logging of the well. If economically adequate reserves have been found, production facilities are installed, development wells drilled, and production initiated. During the production phase, servicing equipment is used to re-enter producing wells to do remedial work, such as control of water production or formation sand incursion, and to install and maintain artificial lift devices. In many fields, substantial additional oil is produced by secondary recovery techniques such as water or natural gas injection, and EOR techniques, which include flooding with materials such as steam, carbon dioxide, or chemicals.

Throughout the life of a field, remedial, stimulation, and recompletion work is performed on wells to maintain production. These activities represent the major part of the work performed by production service companies.

This highly competitive and complex industry operates a vast network of supply and service companies located in nearly two-thirds of the states. Apart from the planning, supervising, operating, and accounting for drilling and producing oil and gas wells, nearly all field work is done by the supply and service sectors of the industry. Many are small independent contractors. Services that are supplied directly in the field include geophysical surveys, geological supervision and surveillance, drilling services, offshore services, offshore platform design and construction, stimulation, surfactant injection, and well servicing rig work.

As discussed in Chapter Five, drilling activity rises and falls with crude oil price. Figure 46 shows that seismic crew count also correlates with crude oil price, accelerating during 1978 and 1980 and peaking just before the price peaked in 1981. With declining prices, crew count dropped by nearly half from 1981 to 1983. In September 1986, it was down to 21 percent of the September 1981 high. The International Association of Geophysical Contractors' dues-paying U.S. membership declined from 275 in September 1981 to 132 in September 1986.

The NPC surveyed more than 100 service organizations with a questionnaire asking for comments on the effect of the recent decline in activity on the petroleum industry infrastructure. The most pertinent questions were on the availability of technical and skilled personnel, loss of vital equipment, lag time to re-equip and re-man the industry, and financing problems. Except where otherwise noted, the following discussions are based upon these responses.

Responding to the drop in seismic crew demand, a major geophysical contractor reduced personnel 82 percent from December 1984 to July 1986. Surplus equipment, much of which is relatively new, is being sold at distress prices.

An independent consulting firm's experience is an example of what has happened to small exploration service companies. Organized in 1973, it grew rapidly and, in 1981, it had 385 employees, $10 million in capital equipment, and did $20 million in revenues. It is now out of the seismic contracting business, has 86 percent fewer employees, and owes $5 million after selling its field equipment to an Asian country at a fraction of cost.

A major wireline service company reduced personnel by 32 percent during the first half of 1986, closed its training centers, deactivated 38 percent of its logging trucks, and curtailed

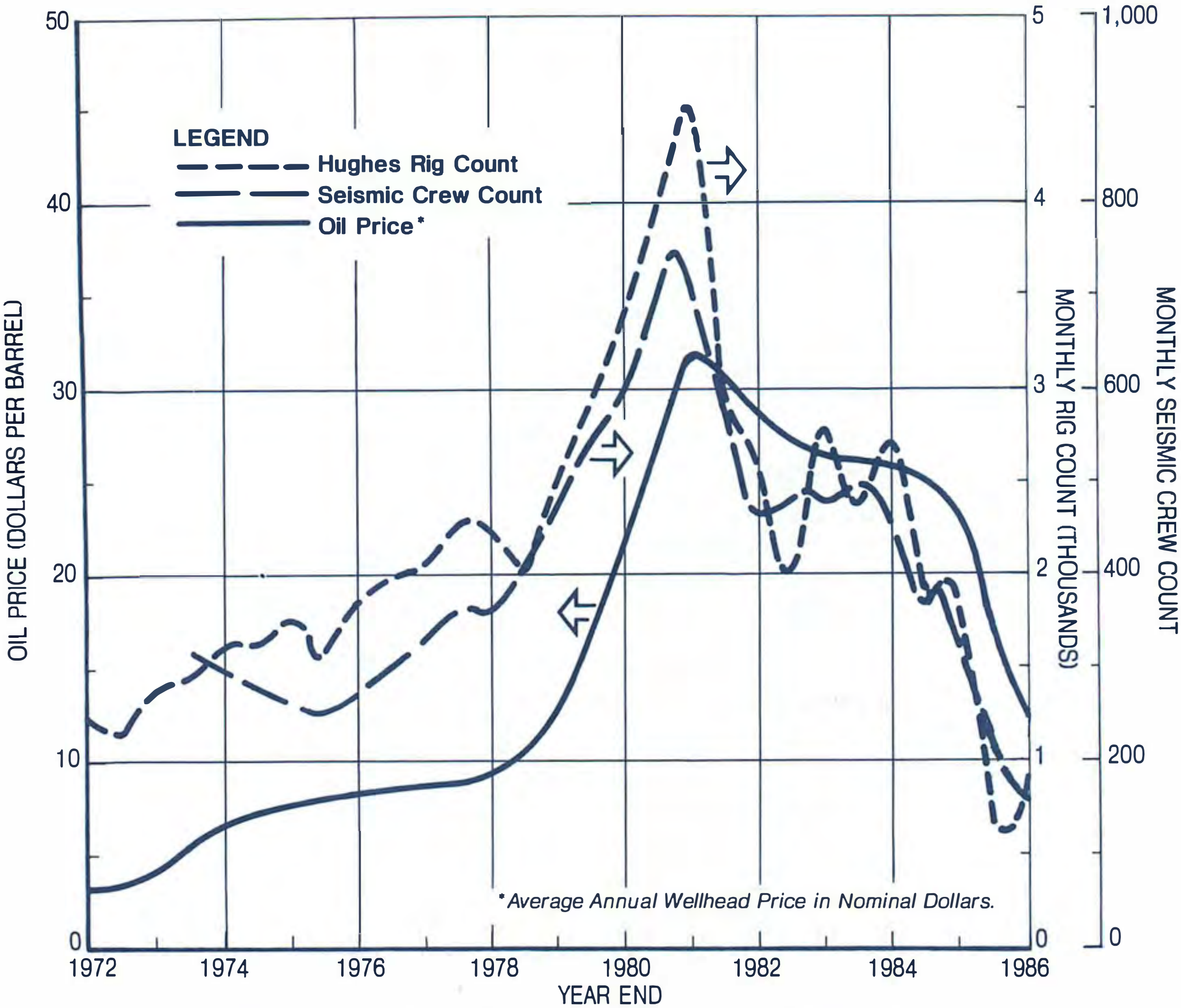

Figure 46. U.S. Oil Price, Seismic Crew, and Rig Activity.

SOURCE: *Seismic Crew Count Data: Society of Exploration Geophysicists.*

manufacture of logging equipment. Additional reductions were planned for later in the year. Fewer funds are being directed to research and development, which they expect will have a significant negative effect on exploration, development, and production capability in the early 1990s.

Another wireline service company had reduced personnel in mid-1986 by 75 percent from the 1983–84 level. No equipment was being manufactured and replacement of worn equipment was financed by cash flow, since the company has no borrowing power.

Service Industry Financing

As has been noted, much of the service industry is composed of small companies providing local services to the exploration and production sector of the petroleum industry. Financial data on the impact of declining oil prices on these small companies are difficult to obtain, but security analysts do follow the performance of the larger companies. For the 110 publically traded oil service, equipment, and drilling companies monitored by Simmons & Co., net losses for the most recent 12 months available at December 31, 1986, totalled nearly $5.0 billion, not including the fourth quarter of 1986. Only 18 of the 110 companies were actually profitable, and in virtually every case this can be related to their non-oil field activities. Membership in the International Association of Drilling Contractors, which from 1972 to 1982 tripled to more than 1,000, dropped 30 percent in 1985, and another 15 percent at the end of 1986.

In oil producing areas, financing locally is very difficult for small independent producers and service companies. The condition of many oil country banks is precarious because of the loss of collateral value in oil and gas reserves—which have been written down as much as 60 percent—and service and supply company assets that have been devalued much more. This situation has brought about severe state and federal regulatory restrictions on bank lending. Without traditional bank sources of funds, and as long as these conditions exist, small producers and service companies must finance operations on current income.

Employment

U.S. oil and gas extraction industry employment has fluctuated with the price of oil, as shown in Figure 47. From the peak year, 1982, total oil and gas extraction employment dropped from an annual average of 708,000 to 570,000 in December 1985 and 422,000 in December 1986. The total loss in jobs from 1982 through December 1986 was 286,000, a 40 percent decline. Service industry employment decreased from a 1982 annual average of 435,000 to 315,000 in December 1985 and 206,000 in December 1986, a loss of 229,000 jobs (53 percent) from 1982. This indicates that 80 percent of the total loss of jobs was in the service industry. The recent API study, "Two Energy Futures," states that for every $1 billion reduction in oil and gas investment, the petroleum industry will lose more than 10,000 jobs, and other industries nationwide could lose more than 8,000 additional jobs.

According to the study, "The United States Oil Industry in Transition," published by Southern Methodist University's Center for Enterprising, more than 96 percent of the production companies in the United States employ fewer than 50 workers. Less than 20 percent of production workers are employed by establishments of 500 or more employees.

Professional Personnel

University trained geologists, geophysicists, and petroleum engineers are critical for the exploration and production segment of petroleum operations. Enrollments in colleges offering these courses have been somewhat cyclical and have also been responsive to the perceived demand for graduates, which is influenced to a major extent by oil prices.

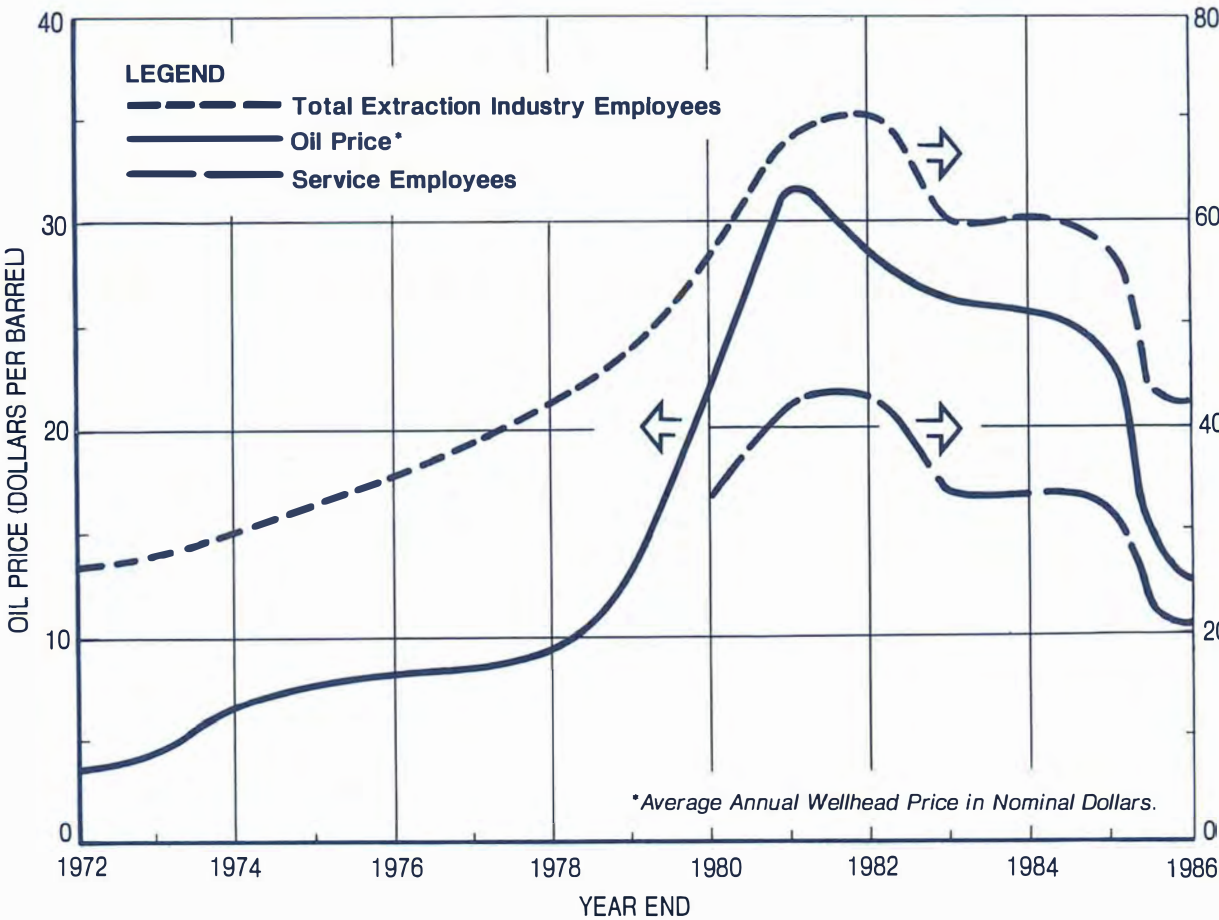

Figure 47. U.S. Oil Price, Oil and Gas Extraction Employees.

SOURCE: *Employee Data: U.S. Department of Labor, Bureau of Labor Statistics LABSTAT Series Report; Total Extraction Industry Employees (SIC 13); Service Employees (SIC 138—N/A before 1980).*

A survey by the NPC of major universities with large enrollments in geology and petroleum engineering shows that enrollments peaked in the early 1980s and have declined rapidly since. Results of the survey from 10 responding schools are summarized in Table 45. From 1966 to 1972, enrollment in geology increased 60 percent and enrollment in petroleum engineering increased 25 percent after declines of 47 percent and 64 percent, respectively, from 1957 to 1966. From 1972 to 1981, enrollment in geology more than doubled and petroleum engineering increased six fold. By 1985, enrollments were down 42 percent in geology and 53 percent in petroleum engineering from the 1981 high, and in 1986 dropped another 15 and 29 percent, respectively. The percentage of students in graduate schools has increased for both disciplines, while total enrollment has declined.

A survey of 13 universities offering degree programs or options in petroleum engineering was reported by the Society of Petroleum Engineers (SPE) in October 1986. The SPE report shows that there has been a large oversupply of petroleum engineering graduates since the 1980-81 academic year. The number of job-seeking graduates increased from about 900 in 1981 to about 1,650 in 1984 and 1,550 in 1985. The number of campus hires was nearly in balance with supply in 1981, but averaged about 750 in the next three years. In 1986, there were only about 400 jobs for 1,400 graduates. A forecast by SPE shows job-seeking graduates declining rapidly to 600 in 1989, with 500 being hired on campus.

The cumulative oversupply of job-seeking petroleum engineering graduates from 1981 through 1985 is about 2,600, and an oversupply of 2,300 is projected through 1989. It is probable that sufficient technical manpower would be available in the event of an upturn in the oil and gas economy in the short term. However, these numbers may be misleading. Many of the recent graduates, as well as experienced employees recently terminated, have moved or will move to other industries.

The Society of Exploration Geophysicists surveyed five universities that have historically graduated geophysicists regarding fall 1986 enrollment. They are the Colorado School of Mines, Cornell, Stanford, Texas A&M, and the University of Texas. Undergraduate enrollment is down about 50 percent from the previous year, while graduate enrollment is holding steady. One university reported that more than one half of the undergraduates were seniors and only two freshmen enrolled. Corporate financial support has declined, but is still reasonably strong for research projects.

The American Association of Petroleum Geologists surveyed 2,115 active members in mid-1986. Responses from 1,473 indicated that 35 percent of the members in Oklahoma and Colorado were unemployed, 26 percent in Louisiana, 24 percent in Texas, 10 percent in California, and 20 percent in other states.

In the longer term, the negative impact of the 1980s experience of universities and graduates in the fields of geology and petroleum engineering will adversely affect enrollment in these fields. Careers in the oil industry will not be viewed as stable, secure, or attractive as they were in the past. Fewer graduates, and the firmer entrenchment in alternative careers of graduates not hired and trained by petroleum companies, will probably impede the ability of the industry to respond to an upturn in activity.

Skilled Personnel

Executives in the oil service industry estimate that a period of about three years is required to train personnel for skilled oil service jobs. For highly skilled jobs, seven to ten years may be required. A major service company estimates the cost of recruiting and training skilled personnel is from $7,500 to $30,000 each.

By the end of 1986, the oil service industry was a small fraction of the size it was in 1981–82. It is believed that most laid-off drilling crews have found or will find other jobs in the skilled labor market.

Companies that specialize in the manufacture of production pumps, portable rigs, and other equipment used extensively in the production of oil and gas have been forced to cut back, close factory operations, and lay off both skilled labor and professionals.

Equipment

The exploration and production sector of the oil and gas industry employs many diverse technologies and types of equipment in the exploration, drilling, development, and production of oil and gas resources. The geological and geophysical service group uses much specialized technical equipment in measuring, processing, and interpreting data from the subsurface relating to the exploration and development of oil and gas. The major equipment used by the oil field service industry may be generally grouped under drilling equipment, production equipment, and well servicing and transportation equipment. The industry is a major consumer of tubular steel goods, in the form of drill

TABLE 45

UNIVERSITY ENROLLMENT

	Geology				Petroleum Engineering			
	Under-graduates	Graduates	Total	Percentage Change	Under-graduates	Graduates	Total	Percentage Change
9 Schools								
1957	1,115	215	1,330		1,468	67	1,535	
1966	471	232	703	-47	453	104	557	-64
1972	727	433	1,160	+60	601	97	698	+25
10 Schools								
1972	941	556	1,497		731	126	857	
1981	2,555	776	3,331	+123	4,858	267	5,125	+498
1985	1,132	800	1,932	-42	2,026	382	2,408	-53
1986	844	796	1,640	-15	1,313	405	1,718	-29

9 Schools Responding, 1957–1972: Louisiana State University, Missouri School of Mines, Montana School of Mines, University of Oklahoma, Texas A & M University, Colorado School of Mines, Virginia Polytechnic Institute, Stanford University, and University of California at Los Angeles.

10 Schools Responding, 1972–1986: All the preceeding schools, plus the University of Texas.

pipe, casing (structural lining of well bore hole), tubing (to bring oil and/or gas to the surface), and the line pipe to take oil and/or gas to production facilities, storage tanks, and transmission pipelines.

The Cost Study Committee of the Independent Petroleum Association of America reported in October 1986 that the supply of tubular goods (U.S. net shipments plus imports) decreased from a high of 6.5 million tons in 1981 to 2.8 million tons in 1985, a reduction of 57 percent. Tubular goods use in drilling and production has a significant impact on the steel industry. This demand can be compared with that of the automobile industry, which uses about 1,250 pounds of steel per average American vehicle. The steel content of tubular goods shipments was equivalent to 10.4 million vehicles in 1981, 4.4 million in 1985, and an estimated 2.6 million in 1986. Domestic mills supply about 45 percent of tubular goods used in the United States.

Many companies in the oil field service industry are being forced to dispose of idle equipment to cut costs. This is reflected in the almost daily auctions in which modern drilling machinery and oil field equipment are being sold at a small fraction of manufactured cost. This distressed market for used equipment limits the benefit of selling the equipment, and many companies have and are continuing to be forced into bankruptcy.

Drilling and well servicing equipment prices since 1973 have fluctuated at even higher rates than drilling activity, contributing to the wide swings in drilling costs. A study by Hadco International, Inc., a consulting and appraisal firm, reported that the rapid growth in equipment demand and sales in the 1970s became frantic in 1980 and 1981. With financing readily available, some used equipment assembled by brokers and dealers sold at new prices. The situation was made worse by speculators buying rigs in the manufacturing line and selling on delivery to the highest bidding contractor, driving prices to very high levels.

With the drilling slump starting in 1982, manufacturers were caught with huge inventories, competing with the great number of idle rigs for sale. Prices dropped 52 percent in 1982 and another 33 percent in 1983. During the first half of 1986, sale prices dropped almost in half. Two-thirds of all sales were at auction, and less than 4 percent were direct sales. Auction prices in 1986 were about 4¢ to 6¢ on the dollar compared to 1981 new equipment prices. Purchasers are dealers and investors anticipating a future increase in demand. Some banks and financial institutions that own idle rigs are retaining rather than disposing of them in the current market.

Hadco also reported that exports have had little effect on the rig market because of the decline in drilling throughout the non-communist world. The well servicing rig market has been adversely affected by the steady increase in imports of these rigs from 5 percent in 1980 to 44 percent in 1985.

The Reed Tool Company conducts an annual U.S. census of active and available rotary drilling rigs during the first two weeks of August. A rig is reported as "active" if making hole during the census or if it has drilled at any time within 30 days prior to the count. The Reed Census of active rigs is always higher than the Hughes count, which reports only rigs that are actually drilling when surveyed each week. An available rig is defined as one that can be rigged up and able to make hole within 30 days with a capital expenditure of less than $50,000. A rig stacked for longer than three years is not counted regardless of its reported condition. Rigs are not counted unless they are capable of drilling to more than 3,000 feet and usually employed for drilling. Results of the Reed Census and the annual average Hughes count of working rigs are shown in Figure 48.

The wide spread between Reed available and Reed and Hughes active counts in the early 1960s had narrowed by the mid-1970s and remained very close through 1981, when the Reed utilization rate was 98 percent and the Hughes 79 percent. In 1982, while the Hughes rig count took a precipitous drop from the 1981 average of 3,970 to 3,105, available rigs continued to climb to a high of 5,644. In 1985, available rigs had declined to 4,409, Reed active to 2,625, and Hughes to 1,968. The August 1986 Reed Census showed 3,993 available and 1,052 active rigs, a 26 percent utilization rate, while the average Hughes count was 730, a utilization rate of 18 percent.

The surprisingly small decline (9 percent) in the Reed available rig fleet from 1985 to 1986 is explained by Reed as caused by contractors maintaining their idle equipment, most of which is relatively new since the marginal rigs were retired between 1981 and 1985. Some contractors have rotated their rigs from stacked to active to keep them in operating condition.

The 1986 Reed Census showed that 2,002 rigs had been stacked up to one year, 503 from one to two years, and 80 from two to three years. This indicates that if drilling activity continues at a level of 800 to 1,000, the available fleet could be reduced during the next three years to about 1,400, as rigs are considered unavailable by Reed after three years out of service.

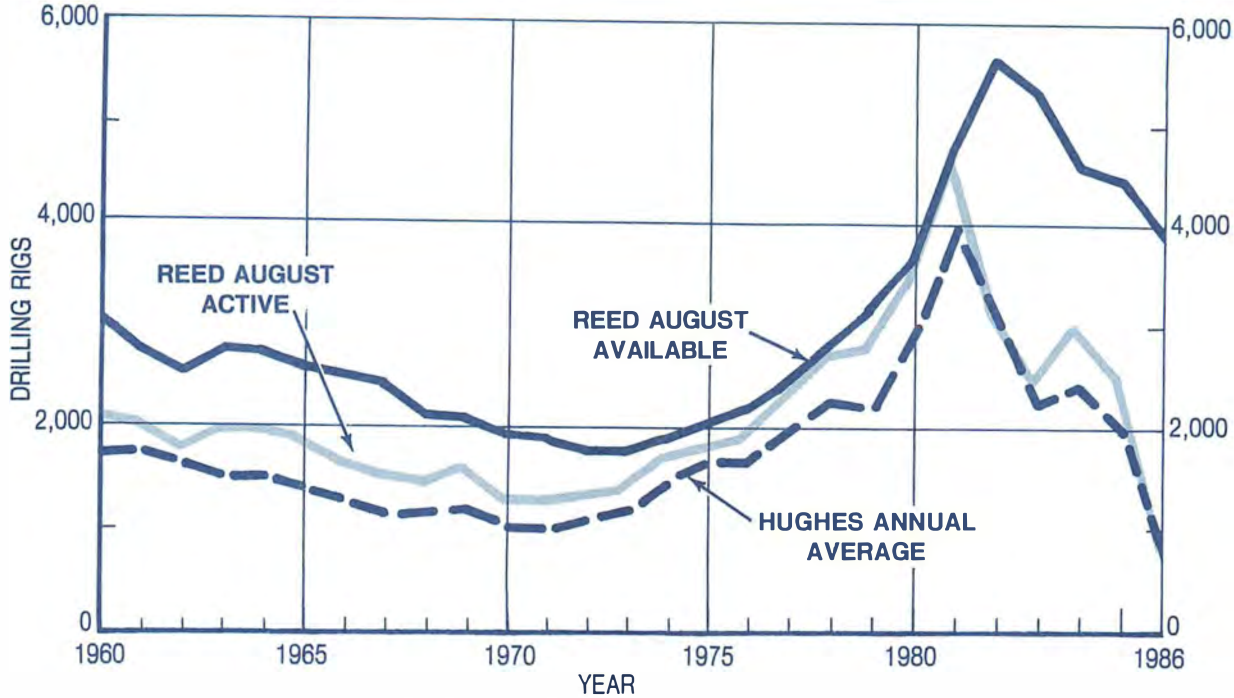

Figure 48. Drilling Rig Activity and Availability.

During October 1986, Smith Tool, in cooperation with the International Association of Drilling Contractors, surveyed U.S. land drilling contractors for rig availability. The survey showed 3,054 rigs as market ready and 762 additional not offered because of technical deficiencies or market conditions, making a total of 3,816. These figures bracket the August 1986 Reed land rig census of 3,752 available.

The decline in U.S. drilling activity includes the offshore. Peak mobile rig use occurred in December 1984—232 of 249 available mobile rigs under contract, a 93 percent utilization rate—and lagged the onshore decline by three years. Offshore Data Services reported utilization of mobile offshore rigs in the Gulf of Mexico bottomed at 25.4 percent in mid-August 1986 (62 mobile rigs under contract of 244 available). On December 1, 1986, there were 50 of the 150 available platform rigs under contract in the Gulf of Mexico (33 percent utilization). During peak Gulf of Mexico development drilling in 1981, 154 of the 175 available platform rigs were under contract, a utilization rate of 88 percent.

In the short term, the 1986 oversupply of rigs and capable contractors can satisfy increasing demand. However, with time, the idle fleet will continue to decline. Idle equipment is being cannibalized for spare parts; lying idle reduces the useful life more than if equipment were being used and regularly maintained. Much equipment has been repossessed, and is frequently not properly preserved, worsening the attrition.

While the impact of the recent price decline was initially the greatest on drilling equipment demand, production and well servicing equipment are also severely affected. A Dresser Industries, Inc., count of workover service rigs shows that utilization declined in 1986 to 31 percent of the estimated 7,939 serviceable rigs, the lowest levels since records began to be kept in the early 1970s. New drilling and servicing rigs are not being built, few new production facilities installed, and fewer replacement parts are needed by the remaining smaller fleet of working equipment. The effects of these reduced demands are felt in other industries not directly related to the oil and gas business, such as general machinery and equipment manufacturers, primary iron and steel, transportation, and insurance.

Future Response of the Oil and Gas Service Industry

The ability of the oil and gas industry to reequip in the future will be limited by several factors. The fragmentation of equipment and the lack of economic incentive or ability to maintain idle equipment will reduce its availability when demand increases. There is a substantial cost associated with reactivating a stacked rig even if it were properly preserved. Many of the manufacturers of oil field service equipment are no longer in existence, or have disposed of much of their manufacturing equipment. So before the oil and gas industry can re-equip, the manufacturers of the equipment must re-equip. The availability of funds for rebuilding the industry's service and supply sectors could be a problem in the event of an upturn in drilling activity.

A turnaround in drilling activity would require the rehiring of personnel. The longer the period of depressed drilling persists, the more difficult it will be to respond to a rapid upturn. Both skilled labor and professionals will become well established in new jobs or careers and will be reluctant to leave. The substantial training that may be required for new hires will slow the response. Furthermore, the skilled personnel who must do the training will be less productive than if they were directly involved in exploration and production activities. The "boom-bust" experience of the 1980s will be a deterrent to recruiting.

All of these factors introduce time lags into the ability of the service industry to respond to any future increase in demand for its services. The time lags are a function of the duration and depth of low oil and gas prices and could extend for several years.

During the time that the infrastructure is being rebuilt in response to a sharp upward shift in prices, shortages of rigs, equipment, service capability, and crews will probably occur. These shortages could drive up the cost of drilling to high levels similar to those that occurred during the 1970s and early 1980s. From 1972 through 1981, drilling costs in the United States increased at an average annual compound growth rate of 17.6 percent per year. Drilling equipment costs increased at 15 percent per year and well operating costs at 14.4 percent per year over the same period, while the U.S. GNP deflator increased at 7.6 percent per year. The substantial real increases in costs of drilling, equipment, and operating reflect the inefficiencies of rapid increases in industry activity.

During 1986, drilling and completion revenues were destructively low for the service industry. Drilling day rates were based on cost of labor and supplies, less the cost of a stacked rig. These rates were reduced so that a nucleus of skilled employees could be retained. Much of the service and supply industry had gone out of business and those remaining operated at a loss. Major restructuring will improve their financial position, but many more service companies will go out of business before the supply drops to the level of demand. On November 10, 1986, the *Oil and Gas Journal* reported that according to Kidder, Peabody & Co., there had been 24 major service, supply, and manufacturing mergers and joint ventures. All segments of the industry are consolidating to cut overhead, gain market share, cut manufacturing and operating costs, and increase the efficiency of remaining personnel and equipment. In the future, demand for the services of the surviving companies will increase the cost of drilling and well completion.

The situation today is entirely different from that of the late 1970s, when a healthy industry was ready, willing, and able to expand in response to increasing crude oil prices. There was an optimism that made capital available to finance rapid expansion. A survey of oil field equipment manufacturers by the NPC in 1979 showed that all were expanding and were capable of increasing capacity by 25 percent in a short time. Many of these manufacturers and some of the institutions that financed them are now out of business.

Research and Development

Another area severely affected by the current downturn is exploration and production research. Large and small companies alike have cut back sharply on research and development budgets and personnel. Grants to universities and other research institutions also have been restricted. These cuts will eventually reduce oil and gas production rates because most of the research expenditures being deferred are in programs designed to produce oil and gas in the future. Examples are deep water drilling, improved seismic methods, and enhanced oil recovery.

Export of Technology

The U.S. domestic drilling and oil field service industries have essentially provided the world with the technology to explore, drill, develop, and produce the world's oil and gas resources. They still lead and sustain the modern worldwide drilling industry. But the technology has been readily shared with the world, and the current collapse of this industry may permanently affect the industry's role as an exporter for the United States. U.S. manufacturers with plants around the world have shut down their oldest and most inefficient facilities, most of which are in the United States. Those remaining in operation are the new, efficient overseas plants that came from expansion in the international market. Foreign companies, many of which are state owned, are taking advantage of government or national programs that encourage the development of their own oil field service industries. As in other industries, the United States' position of supremacy is being eroded, to the detriment of the nation.

When prices eventually rise as world excess productive capacity is exhausted, the domestic drilling, oil field service, and manufacturing companies may find that a significant share of the technology and market they have developed over the last 100 years has been lost to foreign competition.

Impact on Communities

Operating bases for supply and service companies are almost all in small cities and towns near oil and gas fields to minimize transportation time and cost. Oil booms such as in the late 1970s severely impact the infrastructure of host communities. Increased community services such as schools, streets, utilities, housing, banks, and merchants are required. With the sharp recent downturn in oil and gas activities, the communities must pay for the projects initiated during the growth period from an eroded tax base.

The impact of the dismantling of the service industries has been extremely difficult on the people of oil-producing areas. Service, supply, and manufacturing companies question their ability to exist from day to day. For example, Houma, Louisiana, during the first half of 1986 had six independent companies liquidate. They had been in the business of offshore production service, boat building, oil tool rental, tug and barge construction, and retail furniture and appliance sales. Before the recent decline in oil prices, these companies each had assets of $1 to $5 million, annual sales of $2 to $6 million, and from 25 to 275 employees.

Lafayette is the hub for South Louisiana oil and gas production operations, supply, and services, and with the oil boom, experienced population growth from 69,000 in 1970 to 82,000 in 1980 (19 percent). Lafayette Parish grew at an even greater rate, from 112,000 in 1970 to 150,000 in 1980 (34 percent). During the 1973–79 period, about 12 percent of Lafayette's employment was oil and gas related, accounting for 23 percent of the personal income. With the decline in drilling activity, unemployment in Lafayette Parish increased from 6 percent in March 1984 to 11.8 percent in March 1986 and was near 14 percent in September. Lafayette building permits decreased from a high of $26.5 million in April 1984 to $3.3 million in April 1986 (88 percent). Bank deposits decreased 6 percent, and taxable retail sales dropped from $184 million in March 1985 to $139 million (24 percent) in March 1986. The decrease in sales tax collections has forced the postponement of planned street and drainage projects.

CHAPTER SEVEN

INSTITUTIONAL FACTORS

INTRODUCTION

Energy policy is a component of overall public policy, and is comprised of such diverse policy decisions as leasing, environmental issues, tax policy, and consumer issues. The goals of energy and public policy can be in conflict, and an optimal energy policy is seldom achieved. However, it is in the best interest of the nation that a policy which recognizes environmental and energy concerns be developed.

Environmental goals and the urgent need to develop adequate energy supplies for the nation are not mutually exclusive. As in the case of access to federal and state lands, the public interest can best be served by cooperation in developing and implementing programs based on an understanding of all pertinent issues.

U.S. federal and state taxation policies directly affect the oil and gas industry's incentives to explore, drill, and produce oil and gas. These policies also affect the availability of funds for the industry.

This chapter addresses institutional factors in four sections. The first two sections cover the environmental policies and regulations that affect the supply of oil and gas and the demand for oil and gas and their alternatives. The third section covers non-environmental policies, such as taxation, that affect the supply of oil and gas. The fourth section covers non-environmental policies that affect the demand for oil and gas.

ENVIRONMENTAL CONCERNS, POLICIES, AND REGULATIONS AFFECTING OIL AND GAS SUPPLY

Implementation of new environmental policies regarding oil and gas exploration and production may have a marked effect on future domestic energy supply and demand. Environmental laws and regulations can improve the quality of life, yet there must be a balance between environmental concerns and the economic and political costs of ensuring adequate energy supplies. The relative risk to human health and the environment should be identified and quantified. It is not possible to live in a risk-free situation, and the cost of incremental controls may or may not be justified by the corresponding decrease in risk. To ensure that balanced policies are developed between the environmental community and the petroleum industry on these issues, regular government sponsored conferences with representatives of these groups could focus on such concerns. As indicated in the following pages, significant disagreements exist among these groups on the magnitude of the environmental effects on the nation. These discussions could provide a starting point to narrow these differences in perspective.

Access to Federal Lands—Offshore

The Outer Continental Shelf Lands Act Amendments mandate a leasing process aimed at conducting lease sales according to a specific schedule, ensuring that environmental risks are fully addressed, that use conflicts are identified and reconciled, and finally that Outer Continental Shelf (OCS) oil and gas resources are found and produced. The Department of the Interior publishes a 5-year lease plan that sets a schedule of sales and determines when and where offerings are to occur. Each sale on the schedule goes through an extensive planning process before the sale.

Specific decisions regarding deferral and lease stipulations are determined in the planning process for individual lease sale offerings.

The planning process offers a 24- to 28-month period of intense evaluation of resource potential, environmental conflicts, and socioeconomic costs and benefits. As in the development of the 5-year schedule, there are many opportunities for direct public input into the process that leads to the decision to offer leases for bid. It is here that tract withdrawal is and should be considered. It is also here that special stipulations are developed to address and mitigate conflicts. Only after this planning and evaluation have taken place can a decision to lease be made.

The primary area of concern regarding offshore federal lands access is California, which has been identified as having a high potential for significant hydrocarbon deposits. Fiscal year 1986 appropriations for the Department of the Interior contained a leasing moratorium covering large portions of the federal OCS off California. This moratorium prohibited the leasing of 6,460 offshore tracts covering over 37 million acres, or about 63 percent of the entire California OCS planning area (Figure 49).

Discussions and proposals for fiscal 1987 and beyond had called for the prohibition of leasing on some or all of the 6,460 offshore tracts under the existing moratorium until after the year 2000, except in a national emergency. A compromise in the House Appropriations Committee averted a moratorium in fiscal 1987, but delays any California OCS lease sale until at least February 1, 1989. The moratorium language included by the Appropriations Committee precluded debate by the appropriate oversight committees. Although the result may not be called a moratorium, it actually delays any further leasing for at least two years.

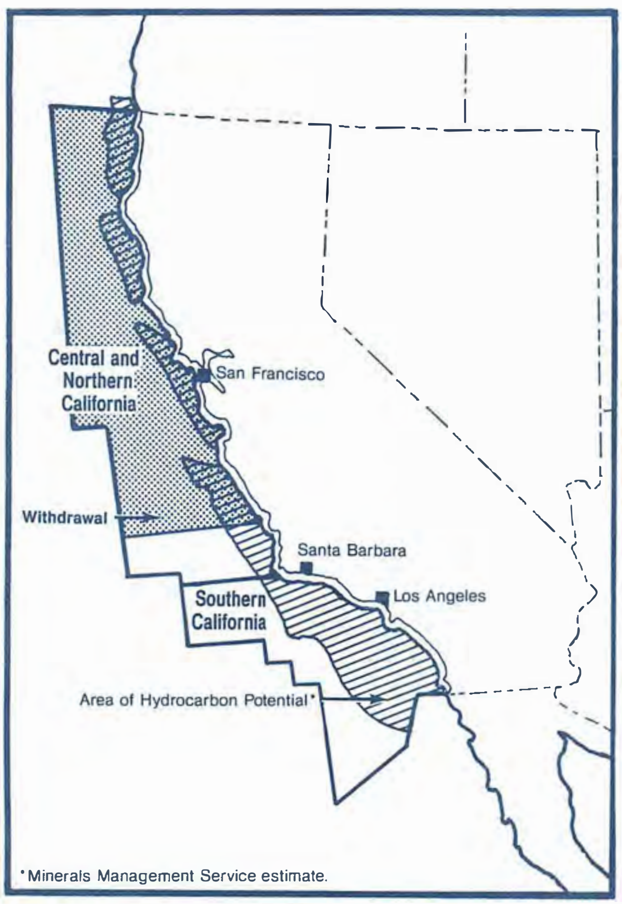

Figure 49. Pacific OCS Region Withdrawals.

Potential federal and state revenues from lease bonuses and royalties in the moratorium area are estimated to be from $4.3 to $17.3 billion in net present value.[1] These figures are based on bonus payments of one-half the historical average of $1,590 per acre leased for the California OCS, a one-sixth royalty, and an average price per barrel of $24. If the moratorium is not lifted, foregone oil production of 172,000 to 688,000 barrels per day will result in a corresponding rise in oil imports. Also, from 66,000 to 265,000 jobs, across numerous industries covering a widespread geographical area, would not be created.[2]

Reserve estimates for the area in the present moratorium range from Minerals Management Service estimates of 1.25 billion barrels to industry estimates of up to 5 billion barrels of crude oil equivalent. Previous exploration activities have shown the presence of hydrocarbons in five of six geological basins tested. This is part of the reason for the optimistic industry estimates on reserves, putting undiscovered reserves at roughly the same level as proved reserves.

Although any moratorium may be lifted in the event of a national emergency, immediate relief from any shortages would not be possible due to the long lead time necessary from lease award until production (often 5 to 10 years).

Tied closely with leasing off the coast of California is the Department of the Interior's negotiated rulemaking process for developing air quality regulations for California OCS operations. Participants include the Department of the Interior, the state of California, Citizens for a Better Environment, The Western Oil and Gas Association, and several local California air

[1]Guerrieri, U., Kobrin, P., Ott, D., and Rustin, M., "The Effects of a Ban on Leasing the Federal Outer Continental Shelf off California for Oil and Gas Development." Washington, DC, August 1985.

[2]Batelle Pacific Northwest Laboratories, "Economic Implications of Accelerated Leasing and Development of Outer Continental Shelf Oil and Gas Resources." Washington, DC, June 1985.

pollution control districts. As air quality issues are often a major deterrent to offshore California development programs, this rulemaking should allow for continued leasing off the coast of California, protect national and local ambient air quality standards, and be acceptable to all parties to the negotiation.

Access to Federal Lands—Onshore

Some of the most promising onshore areas for the discovery of new energy reserves are within lands owned by the federal government. Federal lands total some 720 million acres, approximately one-third of the entire land area of the United States.

The principal reason for congressional action in proposing and imposing further acreage withdrawals from onshore oil and gas exploration is concern for the environment. The petroleum industry shares this concern, but believes that an examination of modern petroleum activities demonstrates that energy production and environmental protection can be compatible. The industry learned a great deal about protecting fragile environments during the development of the Prudhoe Bay field and the Alaskan oil pipeline.

Historically, many of these federal lands were intended to be used in many different ways—including energy and mineral development. However, the petroleum industry recognizes that the dedication of particular government lands to a single purpose may, under certain circumstances, be the highest-value use of these lands. Due to their aesthetic and educational values and for their value as wildlife habitats, it is appropriate that commercial activities, including oil and gas exploration and production, be conducted in recognition of these values.

The National Wilderness Preservation System Act of 1964 set out provisions to designate wilderness areas that were subsequently closed to mineral leasing after December 31, 1983. Although that law did not impose such a prohibition on wilderness study areas, congressional leasing moratoria have placed millions of acres of these study areas off limits to leasing and exploration.

These moratoria restrict the appraisal of oil and gas reserves in lands presently closed to leasing. By not being able to explore these vast areas, reasonable estimates of oil and gas resources are not available to Congress and the Secretary of the Interior for making informed decisions on lands being considered for inclusion in the wilderness system.

The most complete source of resource estimates is still the 1981 USGS Circular 860.[3] It suggests that the most promising onshore areas in the lower 48 states are the Colorado Plateau and Basin and Range, and the Rocky Mountains and Northern Great Plains. The oil potential on the federal portion of the first may be close to 10 billion barrels (much of it in the Overthrust), and the latter areas a little less than half that amount.

A more detailed, but limited, report was published by USGS in 1983.[4] It covers the roughly 74 million acres of designated and proposed wilderness areas in the 11 western states. It provides hydrocarbon estimates for particular areas closed to exploration and production. The acreage by administering agency is: Bureau of Land Management — 27 million acres; Forest Service — 34 million acres; National Park Service — 10 million acres; and Fish and Wildlife Service — 3 million acres. Undiscovered recoverable oil in these wilderness areas could be from 555 to 1,490 million barrels, with a mean estimate of 834 million barrels. Gas estimates range from 5.5 to 16.6 TCF, with a mean of 9.7 TCF. Ninety percent of the oil potential is within 26 million acres in Wyoming, Idaho, Utah, and Nevada, and most of the gas potential is within 20 million acres in Montana, Idaho, and Wyoming.

Admittedly, the existence and extent of oil and gas resources in federal lands withheld from leasing is highly speculative. The only way to prove these resources is by exploratory drilling. The mean estimate of 15 billion barrels of potential resources on federal lands to be discovered onshore in the lower 48 states helps set the context for any meaningful assessment of the "access to federal lands" question.

Alaska is about 90 percent federally owned, and its oil and gas potential is vast. The 1981 USGS mean resource estimate for onshore Alaska is 6.9 billion barrels of undiscovered liquid petroleum and 36.6 TCF of undiscovered natural gas. The USGS mean estimate for the Arctic National Wildlife Refuge is 4.4 billion barrels of undiscovered crude oil reserves, which represents almost two-thirds of total North Slope undiscovered oil reserves, and 18.1 TCF of natural gas. The recent report of the Fish and Wildlife Service of the Department of the Interior tends to confirm these resource estimates.

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[3]U.S. Geological Survey, *Estimates of Undiscovered Recoverable, Conventional Resources of Oil and Gas in the United States.* USGS Circular 860, Washington, DC, 1981.

[4]U.S. Geological Survey, *Petroleum Potential of Wilderness Lands in the Western United States.* USGS Circular 902-A-P, Washington, DC, 1983.

Current estimates suggest that from one-third to as much as one-half of the federal lands are closed to oil and gas leasing, permanently or temporarily (Table 46 and Figures 50 and 51). Even if the federal lands were opened for leasing, only a fraction of the total would likely be developed.

Lack of access is keeping potentially productive lands from being explored and developed. But such activity need not be inconsistent with the goal of environmental preservation. The avoidance of confrontation between philosophies and the consideration of lease access as a pragmatic issue, amenable to

TABLE 46

FEDERAL LANDS LEGISLATIVELY CLOSED TO MINERAL LEASING

	Acres
Designated Wilderness	90 Million
National Park System	43 Million
National Wildlife Refuge System	13 Million
Miscellaneous—Wild and Scenic River System, National Trail System, Historical and Archaelogical Sites, etc.	15 Million
Under Study for Wilderness Designation:	
Forest Service Lands	12 Million
Bureau of Land Management Lands	25 Million
National Wildlife Refuge Lands In Alaska	58 Million
Total	**256 Million***

*About the size of Texas plus California.

Source: American Petroleum Institute, *Should Federal Onshore Oil and Gas Be Put Off Limits?* August 1985.

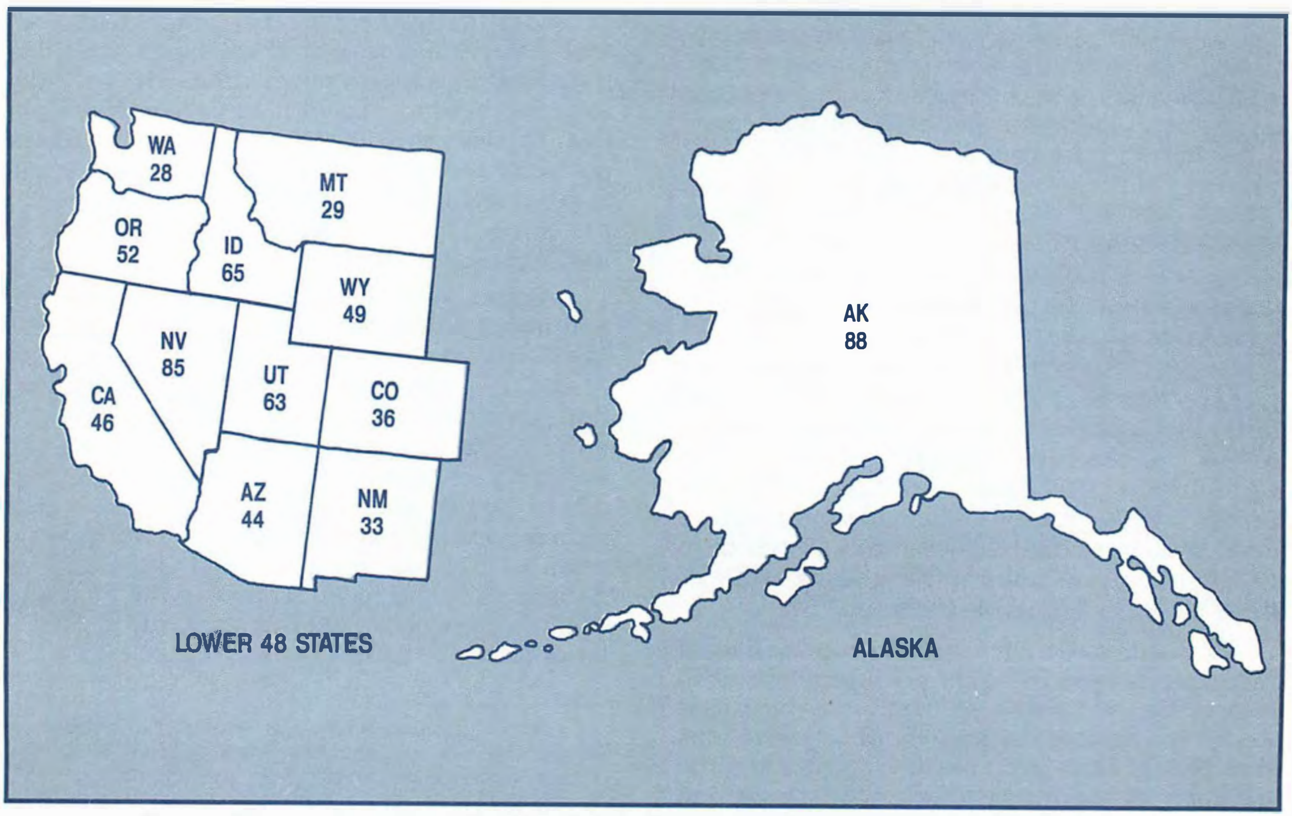


Figure 50. Percentage of Lands Federally Owned in the Western United States (as of September 30, 1983).

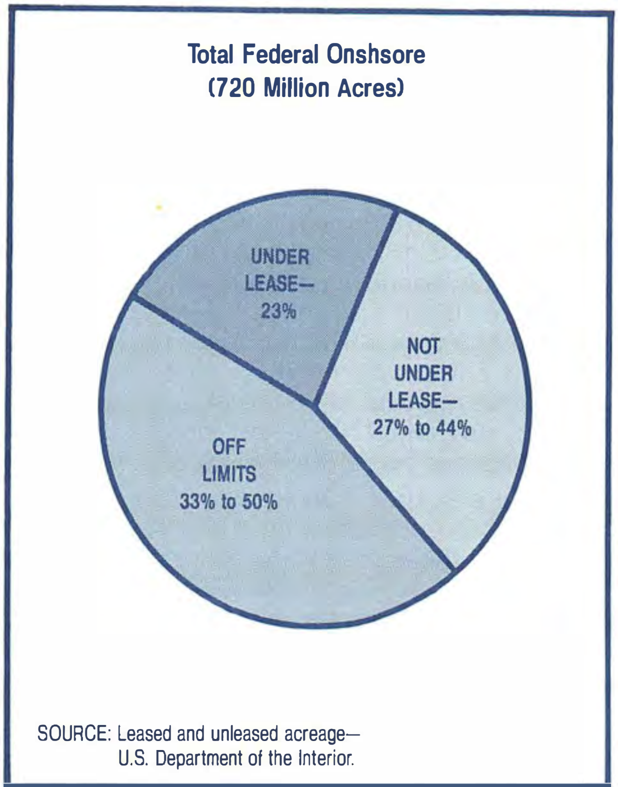


Figure 51. Oil and Gas Leasing Status of Federal Onshore Lands (as of December 31, 1983).

analysis, is in the nation's best interest. This question of access is the type of issue that could be the focus of a conference between petroleum industry, environmental, and government leaders.

Analysis of areas where this conflict has been resolved is most important. A few examples follow.

Compatibility Between Industry and the Environment

The Aransas National Wildlife Refuge in South Texas is the winter home of whooping cranes and also the home of other endangered species, including the southern bald eagle, Attwater's greater prairie chicken, and five species of sea turtles. The refuge has also been the site of extensive drilling and production since 1947, but no seismic work or drilling takes place during the winter when the whooping cranes are in the refuge. Over the years, the whooping crane population has steadily increased.

Avery Island, Louisiana—a private bird sanctuary—has existed in harmony with petroleum exploration and production through careful wildlife management and environmental practices since the early 1940s.

Not far from Avery Island is the Rockefeller State Wildlife and Game Reserve, another petroleum-producing sanctuary that generates a multimillion-dollar income for the state of Louisiana. The revenues from the oil and gas leases are contributing to a trust to continue research on wildlife conservation and for the management of the reserve.

The National Audubon Society's 26,000 acre Paul J. Rainey Sanctuary in southeastern Louisiana lies along the flyway of many species of migratory waterfowl and is in the heart of the wintering grounds of the lesser snow goose. The oil industry has been a part of the sanctuary for more than a quarter of a century, and royalties from petroleum production have played an important role in supporting wildlife management and research in the sanctuary.

Oil exploration in southern Florida, *e.g.* Corkscrew Swamp, has also taken place with minimum impact to the fragile wetland ecology. The Florida Department of Natural Resources conducted a study of oil exploration and production in the Big Cypress Swamp that had been in operation for 30 years and concluded that they had no significant adverse effects on the watershed.

In the construction of a 300-mile pipeline in Wyoming in 1983, the operator made substantial efforts to protect cultural resources along the proposed route. When professional archaeologists identified significant cultural sites and artifacts, the pipeline was either rerouted or other steps were taken to minimize the effects of the construction at the site.

Finally, the magnitude of the environmental, archaeological, historical, and cultural preservation efforts taken during the construction of the trans-Alaska pipeline, in cooperation with the environmental community, were perhaps unprecedented. Investigations along the proposed pipeline route began shortly after construction was proposed in 1969. By 1972, 189 sites of archaeological, cultural, or historical value had been discovered and partially or completely excavated by the University of Alaska and Alaska Methodist University under a $2.75 million industry grant.

This is only a partial list showing some examples of the compatibility of oil and gas exploration and development with the environment. Numerous other measures have been undertaken by a multitude of operators to lessen the effects of petroleum operations in sensitive areas during and after exploration, development, and production. These measures also include reclamation and restoration activities once the commercial operations cease.

Access to Federal Lands—Conclusion

The industry recognizes that some of the most promising areas for oil and gas are also desirable for their scenic, wilderness, and wildlife values. Expensive, lengthy conflicts over such areas could be minimized and possibly avoided if government, industry, and the environmental community would meet and work on an agenda to resolve the issues of greatest importance. The reason for increased leasing of federal land is not merely access to more acreage. The oil industry already has a very large inventory of leases acquired when actual and expected oil prices were much higher. The issue is access to more promising prospects.

Very few areas in the nation have the oil and gas potential of the public lands. As noted earlier, resource potential of the Arctic National Wildlife Refuge appears vast. Producing oil from these properties could significantly reduce the nation's level of oil import dependence. If, for example, the Arctic National Wildlife Refuge would be opened and producing 1.5 MMB/D in 2000, the nation's import dependence would be lowered from almost 70 percent to 60 percent in the lower price trend. Import dependence would decline from 52 percent to 44 percent in the upper price trend.

Exploration and Production Discharges and Wastes—Onshore

The oil industry is now facing possible environmental regulations that could exert a multibillion dollar impact on exploration and production activities. Many of the proposed regulations are focused on the classification and restrictions that may be placed on drilling fluids and cuttings, produced water, and associated wastes—both onshore and offshore. Currently, these wastes are exempted from hazardous waste regulations. The Environmental Protection Agency (EPA) is conducting a congressionally mandated study, scheduled for completion in August 1987, to evaluate retention of this exemption onshore. Preliminary industry estimates project that first-year costs of repealing the exemption could approach $20 billion, with an increase in annual operating costs of approximately $5 billion thereafter.[5] Translating these costs to dollars per barrel of oil equivalent (BOE) produces a cost impact of over $4 per BOE in the first year and over $1 per BOE in subsequent years.

The large volume of exploration and production wastes covered by the current exemption includes drilling muds and cuttings, brines, produced water, completion fluids, workover fluids, and various operational wastes (e.g., tank bottoms). If a "hazardous" determination or special category with additional restrictions is created, current on-site disposal practices such as reserve pits and injection wells could be prohibited. As a result, the above-mentioned wastes would have to be handled as hazardous wastes.

The Resource Conservation and Recovery Act of 1976 exemption for these wastes recognizes that these materials, properly managed, represent a low risk to human health and the environment. Given the considerable effort that has been devoted to developing federal and state regulations for handling exempt exploration and production wastes, additional regulations would not seem warranted.

Previous studies by industry have provided much useful data on the environmental impacts of mud and cuttings disposal practices. However, questions raised by Congress in 1980 in light of current environmental concerns surrounding organic constituents and groundwater contamination are not addressed in present data. Any changes to the exemption of exploration and production wastes onshore would likely have considerable repercussions on offshore operations as well, but no attempts have been made to determine these costs. This may lead the EPA to regulate the oil and gas industry in a piecemeal fashion, perhaps without consideration of cumulative economic or energy impacts.

Exploration and Production Discharges and Wastes—Offshore

One offshore regulatory proposal that has been evaluated is the Offshore Effluent Limitation Guidelines proposed in August 1985. Scheduled for finalization in 1988, these guidelines define the limitations for permits to discharge into offshore waters. As proposed, the guidelines would impose costs on the petroleum industry of from $91.5 million (EPA)[6] to $279.4

[5]ERM—Southwest, Inc., "Potential Cost Impacts on the Petroleum Industry of Eight CRA Issues." Report to API, W.O. #33-10, January 10, 1986. The major component of an approximate $15 billion capital cost involves the upgrading of the Class II injection wells to Class I (±$13.5 billion). The $5 billion increase in operating costs is composed primarily of a $3.5 billion increase in disposal costs for drilling mud and associated wastes. The combination results in a $20 billion first-year cost.

[6]Eastern Research Group, "Economic Impact Analysis of Proposed Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry." Prepared for U.S. EPA, July 1985.

million (API)[7] per year. An analysis for the Department of Energy[8] on only the New Source Performance Standards portion of the proposal shows impacts for the Gulf of Mexico offshore as follows:

- Increased capital costs: $1.4 billion
- Increased annual compliance costs: $0.275 billion
- Lost federal, state, local revenues @$29.20 per barrel
  - — Earlier abandonments: $0.7 billion
  - — Uneconomic fields: $0.9–2.5 billion
- Lost oil reserves
  - — Earlier abandonments of new sources @$29.20 per barrel: 60 million barrels and 80 billion cubic feet
  - — Uneconomic fields
    @$15 per barrel: 500–1,200 million barrels and 700–1,700 billion cubic feet
    @$29.20 per barrel: up to 70 million barrels and up to 100 billion cubic feet

The DOE cost estimate assumes reinjection of produced water in water depths less than 65 feet. Similar regulations for offshore state waters and bay and inland waters would likely have a much greater impact due to the number of wells covered.

Superfund

The reauthorization of Superfund in the closing days of the 99th Congress authorized an $8.5 billion five-year program for cleanup of waste disposal sites and a $0.5 billion five-year program to fund the cleanup of underground tank leaks. The petroleum industry is being taxed $2.75 billion for waste disposal cleanup, or one-third of the program cost. These added costs will reduce the funds available for exploration and production of domestic oil and gas and for upgrading of domestic refineries.

ENVIRONMENTAL CONCERNS, POLICIES, AND REGULATIONS AFFECTING OIL AND GAS DEMAND

Air Emissions

Many of the major items on the legislative or regulatory agenda that could affect petroleum or natural gas consumption and/or consumers directly relate to air emissions. Efforts are being made to reduce hydrocarbon, lead, and oxides of sulfur and nitrogen emissions. All of these efforts, however, cost money, and inequities can arise when these costs are allocated to the players. Will the consumers, producers, or the public pay the cost of controls? At what point does the cost/benefit ratio rule out further controls? These types of questions need to be addressed for each proposal as efforts are made to change laws and regulations.

Gasoline Vapor Recovery

One issue that is being hotly debated is the reduction of gasoline vapor emissions and the system that should be used. Three approaches are being considered. One is at the pump with a Stage II Vapor Recovery System, which transports refueling vapors back to the underground tank from a modified filling nozzle. Cost estimates range widely, from industry's estimate of $20,000 to $25,000 in capital costs and $3,200 per station in annual operating costs, to EPA's estimate of $5,000 to $15,000 capital costs plus $500 to $1,800 in annual operating costs.[9]

Another method of vapor control is a modification of the Onboard Vapor Recovery System, which traps evaporative emissions through the car's tank vent assembly and transports them through a charcoal canister for reclamation. This system can be modified to also collect refueling vapors. Automobile makers estimate production cost increases from $30 to $120 per car. At a 10 million car annual sales rate, costs could be as high as $1.2 billion per year. There is a wide gap between these estimates and EPA's estimate of $19 per car.

The third method would be to reduce the Reid Vapor Pressure of gasoline sold in the United States. The cost of this method is estimated by EPA to be $600 million per year[10] and would increase import dependence.

While the Stage II Vapor Recovery System would provide a measure of control, there is

[7] American Petroleum Institute, "Comments of the American Petroleum Institute on U.S. Environmental Protection Agency Proposed Rulemaking: Effluent Limitations Guidelines and New Source Performance Standards for the Offshore Segment of the Oil and Gas Extraction Point Source Category." 50 *Federal Register* 34592-636, August 26, 1985, and March 15, 1986.

[8] Lewin and Associates, Inc., prepared for U.S. Department of Energy, Office of Fossil Energy, "Estimated Impacts of the Proposed NSPS Regulations on the Reinjection of Produced Water from Offshore Oil Production Facilities." March 10, 1986.

[9] EPA Staff Working Paper, August 1986.

[10] EPA Briefing Paper, October 1985.

much skepticism about the effectiveness of this control program because it is dependent on a vigorous enforcement program similar to the one being run in California. EPA states that the efficiency of this system is 62 percent to 86 percent depending on the level of state enforcement, while they estimate the efficiency of the onboard system at 95 percent. When fully implemented, the onboard system would reduce hydrocarbon emissions by 5 to 6 percent, versus 1.5 to 2 percent for Stage II if fully implemented in the non-attainment areas. The Onboard Vapor Recovery System requires less supervision but needs to be implemented several years before a majority of the motor vehicles on the road are equipped.

The reduction in Reid Vapor Pressure would be the fastest method of control, but would have the highest overall cost and would require increased imports of 250 to 300 MB/D of products or up to 600 MB/D of crude oil. Even if EPA should choose to impose Reid Vapor Pressure controls, this may not bring many states into attainment, which could require those states to also implement Stage II controls in order to avoid EPA sanctions.

In any of these cases, costs will inevitably be passed on to the consumer.

Acid Rain

Acid deposition, more commonly known as acid rain, is the underlying issue for a number of regulatory proposals and discussions that have been taking place over the past few years. Pointing to the risk of irreverisible damage to land and water resources, environmental groups, the Canadian government, and a portion of the general public have called for more stringent federal controls. Others, including many members of industry and the administration, point to the scientific uncertainties about acid deposition and contend that further pollution controls are premature, may waste money, and would impose burdens on industry and the public without assurance of proportionate benefits.

Most of the potential impact of new air emission regulations on oil and gas demand will affect the type of fuel used. Existing installations with the capability may switch fuel, primarily from coal to oil or gas, or from oil to gas. The choice of primary fuel source(s) for new installations will also be affected. The areas most subject to potential fuel switching for existing or new sources are utility and industrial boilers.

Much uncertainty surrounds the timing and nature of possible acid rain control legislation. Such legislation could impact utility and industrial boilers, nonboiler combustion processes, industrial process emissions, and emissions from motor vehicles, especially diesels. The possible effects on the utility industry are enormous—in the multibillion dollar range. A recent Congressional Budget Office study presented several scenarios reflecting emission reduction levels and methods of achieving them.[11] Projected impacts include several billion dollars yearly, with extensive regional employment impacts involving a shift from the high sulfur coal areas of the East to the low sulfur coal areas of the West and East.

A control program may also involve an emission reduction from industrial boilers for both sulfur oxides and nitrous oxides. There could be a significant impact on the cost of energy production, particularly field and refinery operations, in the oil and gas industry. In this case, there would not be the option of fuel switching. Controls on nitrous oxides in vehicle emissions would, however, favor gasoline and methanol fuel use over diesel.

Related Air Emission Issues

The EPA has proposed Industrial Boiler New Source Performance Standards for sulfur oxide in emissions from industrial boilers. The new rules would require a 90 percent sulfur oxide reduction with a 1.2 pound per million BTU cap for new boilers having a heat input greater than 100 million BTU per hour. Current standards impose a limit of 1.2 pounds of sulfur oxide per million BTU of heat input for new boilers larger than 250 million BTU per hour with no percent reduction requirements. The combination of this standard, if enacted, and lower oil and gas prices could substantially alter new boiler fuel choice, increasing demands for gas and perhaps for lower sulfur fuel oils.

The pipeline industry is also struggling with new and proposed regulations as many compressor stations do not have the process and/or equipment to meet air emission requirements. Most of these limitations were developed for refineries and chemical plants where resources are at least available to make the necessary modifications.

New compressor facilities are required to install Best Available Control Technology equipment that will reduce nitrous oxide emissions. Nitrous oxide emissions can be reduced by either catalytic converters or water injection.

[11]U.S. Congressional Budget Office, "Curbing Acid Rain: Cost, Budget, and Coal-Market Effects." June 1986.

Water injection cools the flame, with lower temperatures reducing nitrous oxide emissions. However, this water must be very pure in order to prevent mineral deposits on the turbine blades. Whereas refineries generally have a readily available steam source, pipeline plants do not have this capability. Catalytic converters will also not work in the 900° heat of a gas turbine. According to the pipeline industry, the technology necessary to make either of these processes work at their facilities is not proven and should not be required as Best Available Control Technology.

Environmental Policies and Regulations Affecting Consumption of Alternatives to Oil and Gas

For the next 15 years, the major alternative energy sources to be taken into consideration are coal and nuclear energy. Because of the long lead times to build and license a new nuclear plant, the number (and capacity) of reactors now in operation or under construction represents the maximum to be expected in this century. That number is 121 reactors with a design capacity of 130,000 MW. Any variation will be on the downside, since it cannot be taken for granted that all reactors now under construction or on order (there are only two in that last category) will indeed be completed and on line by the year 2000. The odds are that some will also be abandoned. Moreover, any resumption of orders will not result in operational reactors by the end of the century. Also, some reactors will reach the end of their useful lives and be decommissioned. Thus, the nuclear picture represents a virtually surprise-free scenario on the upside, with a chance for revisions on the downside.

As for major policies and regulations not now on the books, the management of nuclear waste is the outstanding one. At least one federal depository is scheduled to be in operation in 2003. While the procedure for selecting the site is laid down in the Nuclear Waste Policy Act of 1982, experience suggests that the road will be anything but smooth, with all three branches of the government most likely playing a role. Utilities have already begun to pay a fee for federally managed disposal, so that for the time being no further financial burdens are likely to be incurred by them. The only contingency is that a major delay may compel utilities to invest in added temporary disposal facilities.

As for coal, the situation is both more complex and more fluid—more complex in that different parts of the country face different issues and have different policy objectives, and more fluid in the sense that legislation is certain to alter the basic parameters between now and the year 2000. The outstanding success of coal has been as boiler fuel for the electric utilities, which account for 85 percent of all coal consumed domestically. Manufacturing, however, has failed to embrace coal, despite the impressive price differential between coal and oil and gas. Other factors have proved more powerful, among them lack of suitability of coal in many industrial processes, difficulties in the logistics of transportation, ash disposal, and storage, and costs of complying with environmental regulations, which tend to be especially high on a per unit basis for small operations.

As mentioned in earlier discussions, there could be a considerable impact on the coal and utility industries from controls on the quality of coal or stack emissions. One would expect these controls to increase oil and gas demand, since emissions of sulfur oxides from oil and gas are far less than from coal. Thus the competitive position of oil and gas would be improved. There is, however, a qualification. The role of nitrous oxides in the transformation of sulfur oxides to sulfates is not clear. If nitrous oxides are proven to play a crucial role, emissions from motor vehicles, and especially from diesels, might come under tighter regulation. Studies indicate that in some western U.S. locations, nitrates cause the majority of the acidity in acid rain. This may increase the attention to nitrates control.

Coal's competitive position could be helped by substantial progress on the research and development side. When the Synthetic Fuels Corporation was terminated, Congress set aside $400 million to be allocated by DOE for advances in coal-burning technology. Proposals were submitted to DOE in April 1985, evaluated, and nine winners were named on July 25, 1986. There will be an active program in promoting clean coal burning, which was put high on the DOE agenda by the Energy Research Advisory Board. Moreover, the U.S.-Canadian understanding on acid rain commits the United States to invest $5 billion, to be provided in equal parts by government and industry, in devising coal-burning technology designed to reduce sulfur-based emissions. The $400 million program might be considered a first installment.

One noteworthy success story is the Cool Water Power Plant in California—a combined-cycle facility. It uses coal to produce combustible gas under environmental conditions that meet current standards and generates electricity via a conventional gas turbine and from steam produced from the hot exhaust gases. It is too soon to assess the economics, but this might well be a future option for utilities.

Much will depend on government policy. Government funding will be required to maintain or increase a strong coal research and development program, especially since prices of residual fuel oil and natural gas have declined. Whether the fiscal situation will allow this to happen is an open question. If government funding weakens, coal's competitive position is likely to worsen vis-a-vis both oil and gas, as coal incurs added environmental costs that render it less attractive than it has been in the past.

GOVERNMENT POLICIES (OTHER THAN ENVIRONMENTAL) AFFECTING OIL AND GAS SUPPLY

Government policies and regulatory programs imposed at the federal, state, and local levels can serve as either effective stimulants or deterrents to exploration and production activities. Regulations and legislative measures cover a wide range of areas affecting all facets of the supply picture, from tract selection and access to the most promising resource areas to the marketing and sale of end-use products. Further, business planning and investment decisions, which in turn serve to augment or reduce available supplies, can be significantly affected due to shifting and uncertain government policies and priorities.

Four major categories of governmental policies affecting oil and gas supply—pricing and investment, taxation, trade, and international relations—are discussed briefly below.

Pricing and Investment Policies

The pricing and investment policies cover a wide range of issues that affect the return on investment. In the historical context, the discrepancy between "free-market" prices and below-market controlled prices had a significant impact on: the producers' willingness and ability to explore for oil and gas; selection of drilling prospects; the financial risk assumed to bring marginally commercial finds into actual production; and the ability to maintain producing wells and enhance ultimate recovery levels.

To the extent that below-market prices stimulate demand and reduce marginal production, in the absence of competitively priced alternative fuels, the loss of domestic output can only be replaced in the short term by increased reliance on imports.

As indicated in Chapter Two, the price controls imposed on the oil industry as part of the wage and price freeze program of 1971 were a major contributor to the product shortages experienced prior to the 1973 Arab oil embargo and the subsequent shortfalls experienced in the aftermath of the embargo decision. The maintenance of low real oil prices stimulated demand for liquid fuels, yet hindered the ability of producers to bring needed new production prospects on line.

Similarly, the wellhead price disparity between regulated interstate gas and higher priced unregulated intrastate gas, as experienced in the mid-1970s, skewed the availability of the fuel, creating excess deliverability in certain local markets and shortages and curtailment problems in other nonproducing regions of the country.

Price controls disrupt the natural workings of the marketplace by artificially setting commodity values. These controls insulate consumers from the real costs of those commodities and, consequently, encourage additional consumption. This increased demand has the effect of further driving up the price for the unregulated product and increasing the price disparity between the controlled and uncontrolled supplies. Because of the widening price gap, controls are often perpetuated in order to forestall the economic dislocations to consumers, dislocations that are needed to bring the market back into balance.

In an attempt to partially mitigate the effects of controls, the government, in the past, has on several occasions introduced the concept of price vintaging. The intent is to concurrently soften the blow of rapidly escalating energy prices while, at the same time, offering certain "incentive" pricing arrangements to stimulate additional domestic supplies. As a "political" construct, vintaging allows regulators the luxury of selecting an incentive price adequate to bring on new supplies while depriving historical production the benefits of "windfall" profits. However, vintaging can distort the market by imposing artificially different prices for the same product.

Tax Incentives/Disincentives

Tax laws can markedly influence investment decisions and the ability of producers to engage in specific types of ventures. Corporate tax rates, depreciation schedules, and the investment tax credit all affect the incentive to invest and the ability of producers to accumulate capital to finance exploration and production ventures. Changes to the tax code that reduce investment incentives and the ability to generate capital consequently reduce business activity.

Changes in specific oil and gas preference items, such as intangible drilling costs and the depletion allowance, affect the level of drilling activity, the selection of drilling prospects, and the ultimate payout in producible volumes. Further, the timing of particular tax changes can substantially undermine the economics of individual projects and cause otherwise producible oil and gas shows to be commercially uneconomic and consequently never brought into production.

The oil and gas industry has long been accused of receiving preferential tax treatment. Yet, according to calculations by the Joint Committee on Taxation, during recent years the oil industry has paid a larger share of its income in federal corporate income taxes than has the average industry. When the Windfall Profit Tax is included in the computation of federal taxes paid by the oil industry, the industry's tax burden as a percentage of income has been the highest of any major industry.

In addition to general corporate taxes and the Windfall Profit Tax, the industry also pays a variety of severance and excise taxes, royalties, the Superfund feedstock tax, and many other less notable yet increasingly expensive taxes, tariffs, and fees. When taken in combination, these various tax payments substantially affect corporate cash flow and associated exploration and production activity.

Trade Policies

The most obvious trade policy decisions affecting oil and gas supplies are those related to restrictions on imports and exports. On the import side, tariffs, fees, and quotas have been used at various times to curtail domestic demand for petroleum and to stimulate domestic production. The effectiveness of such efforts is, however, more closely related to the size of the fee or the volume limitation provided by the quota than to the general policy signal of a willingness to preserve domestic output or restrain import reliance. In addition, restrictions on imports of technical equipment or other commodities (such as tubular steel for offshore drilling platforms) can also affect production volumes and ultimate recovery levels.

Restrictions on the export of specific refined petroleum products that are surplus to regional demand can result in shortages of other needed products, due to the inability of refiners to dramatically alter their product slates. Similarly, the adoption of trade policies that encourage or otherwise confer a competitive advantage on imports will necessarily undermine the ability of U.S. producers to effectively compete for sales.

International/Diplomatic Policies

The role of U.S. foreign policy is intricately tied to our energy security. Relationships with OPEC and other exporting nations, as well as with oil importing nations, all affect the international supply/demand balance.

The decision by the Nixon administration to resupply Israel during the 1973 Arab/Israeli conflict was the basis used for initiating the oil embargo. The Iranian revolution and the overthrow of the Shah, an ally of the United States, precipitated the Iranian oil crisis of 1978–79. The cooperation of major consuming nations and selected OPEC members during the outbreak of the Iran/Iraq war averted or at least mitigated the recurrence of another such supply crisis.

The ability of the United States to encourage other consuming nations to build oil stockpiles similar to the U.S. Strategic Petroleum Reserve, and to promote stability and peace in the Middle East, will help to avert or mitigate the impacts of future energy crises.

Other Policies

A variety of other policies and decisions may also affect the ultimate availability of domestic oil and gas supplies. Policies and subsidies aimed at promoting specific alternative fuels (for example, nuclear or gasohol) can invariably skew interfuel competition and confer an economic advantage on the production of one fuel type over another. Research and development activities carried on by the government or with the use of government funding, as in the case of EOR technologies, can also affect the supply of particular fuels. Production policies and regulations governing well spacing, plug and abandonment requirements, and production rates may also substantially influence supply.

GOVERNMENT POLICIES AFFECTING DEMAND FOR OIL AND GAS

Any discussion of major institutional policies affecting oil and gas demand necessarily lends itself to grouping and subdividing such policies into those that stimulate demand and those that inhibit or dampen demand.

Of the former group, historical evidence indicates that, during the 1970s, the adoption of price and allocation controls, including regulatory programs such as the entitlements program, significantly contributed to increased U.S. oil consumption and imports by insulating consumers from the "real" costs of energy—all at a time when the United States should have been reducing consumption and imports for energy security reasons. As noted in Chapter Two, the priority user designations in the allocation program, by allowing selected users to receive 100 percent of current needs, similarly encouraged consumption. The entitlements program, by subsidizing imports in the interest of equalizing refiners' crude oil costs, pushed demand higher than it otherwise would have been.

Low regulated prices for natural gas had a similar effect on domestic gas demand. The control of natural gas and oil prices made these fuels more attractive to consumers than alternative fuels and, consequently, increased their relative shares of total energy demand.

As indicated above, there are also a variety of government policies that, when employed, can dampen the demand for oil and gas. The return to free-market pricing in a rising price market and/or the imposition of taxes, fees, or tariffs produces price-induced conservation. The adoption of quotas on imports has also been used as a means for curtailing import dependence.

Other fuel conservation initiatives, such as lowering highway speed limits, allowing tax credits for insulation and weatherization activities, promoting energy efficiency standards—all contribute to a dampening of demand for specific fuels. Promulgating standards for restricting the use of specific fuel types (e.g., the restrictions on gas used as a boiler fuel under the Powerplant and Industrial Fuel Use Act) can also force a shift in demand to alternative energy sources.

Chapter Eight

International Factors

INTRODUCTION

Oil is a fungible, easily transportable, and internationally traded commodity that is vital to the U.S. economy. Petroleum fuels were utilized primarily for lighting in the 1800s, but use increased very rapidly following the development of the internal combustion engine, national electrification, and growth in heavy industry. In 1985, oil's contribution to total U.S. energy use was over 40 percent.

Natural gas is also vital to U.S. energy supply; gas provided about one-quarter of total energy in 1985. Although natural gas is not as easily transported as oil, the nation's extensive pipeline system makes gas readily available in most areas. The United States imports natural gas from Canada, can import from Mexico, and imports small quantities of LNG. Natural gas is used as a feedstock for manufacturing ammonia and methanol, which are internationally traded.

Since 1949, U.S. oil consumption has exceeded domestic production, and the nation has depended upon oil imports to make up the balance. Net oil imports have ranged as high as 46 percent of total U.S. consumption. In 1985, net imports were about 27 percent of total consumption, but in 1986 rose to 33 percent.

Although the United States controls only about 5 percent of non-communist world crude oil reserves, it accounts for 23 percent of crude oil production and 34 percent of oil consumption, as shown in Table 47.

TABLE 47

U.S. OIL POSITION IN THE NON-COMMUNIST WORLD

	U.S.	Total Non-Communist World	U.S. % of Total
Crude Oil Reserves—12/31/85 (Billion Barrels)	28	619	5
1985 Crude Oil Production (MMB/D)	9.0	38.7	23
1985 Oil Consumption (MMB/D)*	15.7	46.4	34

*Includes natural gas liquids, net imports from communist countries, refinery gain, inventory change, tar sands, shale, and synthetic fuels.

Oil is produced, refined, transported, and marketed worldwide, and because of U.S. dependence on imports, it is impossible for the United States to operate in isolation from the world oil market. A significant shortage of oil anywhere in the world inevitably will affect the United States. Even if a shortage did not directly affect U.S. imports, it would drive up the world price of oil. Defense and energy treaties link the United States with many countries and provide for the sharing of oil supplies in the event of a severe supply interruption. A thorough discussion of the oil-sharing provisions of the Agreement on an International Energy Program, signed by the United States and 20 other countries, is included in the NPC report *Emergency Preparedness for Interruption of Petroleum Imports into the United States*, published in April 1981.

OPEC SUPPLY

Table 48 shows OPEC oil production from 1960 through 1985. OPEC was established in 1960 after the government of Iraq invited delegations from Iran, Saudi Arabia, Kuwait, and Venezuela to discuss how the countries could play a greater role in decisions affecting their oil resources. These countries were concerned that their oil revenues were being eroded by price reductions being made unilaterally by international oil companies operating within their borders. Membership was open to any exporting country accepted by all five original members. Qatar became a member in 1961, Indonesia and Libya in 1962, Abu Dhabi (which later became part of the United Arab Emirates) in 1967, Algeria in 1969, Nigeria in 1971, Ecuador in 1973, and Gabon in 1975. As time passed, the group began negotiations with the international oil companies regarding levels of prices, production, and taxes.

In 1971, five-year agreements, known as the Tehran and Tripoli Agreements, were made by Middle East and North African OPEC countries and a number of oil companies. Crude oil prices were increased modestly, then were to be stabilized—except for inflation adjustments—for five years. The agreement was abrogated by OPEC members in 1973.

The energy crisis of 1973 began with the Arab/Israeli war. The war caused an oil-buying panic in Europe and Japan, with nations and industries attempting to purchase as much oil as they could. The posted price for crude oil quickly increased from around $3 per barrel in early October to about $5 per barrel in mid-October, when Saudi Arabia and other Arab states announced that they were cutting back on production and instituting an embargo of shipments of oil to the United States and other supporters of Israel. In 1974, Middle East OPEC countries increased production, but OPEC crude oil postings were also increased to about $12 per barrel. Oil price postings then remained relatively flat through November 1978, with the result that postings in constant dollars declined about 15 percent.

In late 1978, the Iranian revolution interrupted the flow of Iranian oil exports to the world market. In March 1979, Iran resumed exports on a reduced scale, but uncertainty about security of supply persisted in the market. Panic buying and an historic inventory buildup, beginning in the second quarter, led to spot prices as high as $40 per barrel by the end of 1979. Official selling prices for Arabian light crude oil increased in a series of steps from about $13 per barrel on January 1, 1979, to $26 per barrel on January 1, 1980, and premiums of several dollars per barrel were widespread for the next two years.

The reduced Iranian exports early in 1979 were partially offset by increased exports from other producers. Average OPEC production in 1979 was more than 1 MMB/D higher than in 1978. Total non-communist world crude oil production reached a record level of almost 49 MMB/D in 1979. Saudi Arabian crude oil production averaged about 9.5 MMB/D for the year.

The conflict between Iran and Iraq broke out in September 1980, further adding to uncertainty about oil supply and price. Oil exports from both countries essentially ceased for a time. Average 1980 total OPEC production was 4 MMB/D less than 1979 production. By year-end, OPEC posted crude oil prices had been increased to $34 per barrel, with spot prices exceeding $40 per barrel.

After the very abrupt and rapid price changes of 1979 and 1980, the non-communist world underwent the deepest recession since the Great Depression of the 1930s. Demand for oil came down rapidly, as consumers responded by changing thermostat settings, driving less, and adding insulation. Industrial output was reduced by the recession, and industrial energy use declined correspondingly. Many industries instituted conservation programs, as did state and national governments.

At higher prices, the search for oil and gas in non-OPEC countries of the world was stepped up, and non-OPEC production began to increase. The decrease in demand and increase in non-OPEC production lowered the amount of oil required from OPEC, forcing OPEC to reduce production in order to keep supply in balance

TABLE 48

OPEC CRUDE OIL PRODUCTION*
(Million Barrels Per Day)

	1960	1965	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
Middle East																		
Arab Gulf																		
Saudi Arabia	1.3	2.2	3.8	4.8	6.0	7.6	8.5	7.1	8.6	9.3	8.3	9.5	9.9	9.8	6.5	5.1	4.7	3.4
Kuwait	1.7	2.4	3.0	3.2	3.3	3.0	2.6	1.9	2.0	1.8	1.9	2.3	1.4	1.0	0.7	0.9	1.0	0.9
U.A.E.	0.0	0.3	0.8	1.1	1.2	1.5	1.7	1.7	1.9	2.0	1.8	1.8	1.7	1.5	1.3	1.1	1.1	1.2
Qatar	0.2	0.2	0.4	0.4	0.5	0.6	0.5	0.4	0.5	0.4	0.5	0.5	0.5	0.4	0.3	0.3	0.4	0.3
Subtotal	3.2	5.1	7.9	9.5	11.0	12.7	13.2	11.3	13.2	13.7	12.8	14.4	13.7	12.8	8.9	7.6	7.4	5.9
Iran	1.1	1.9	3.8	4.5	5.0	5.9	6.0	5.4	5.9	5.7	5.2	3.2	1.7	1.4	2.2	2.4	2.2	2.2
Iraq	1.0	1.3	1.6	1.7	1.5	2.0	2.0	2.3	2.4	2.4	2.6	3.5	2.6	0.9	1.0	1.1	1.2	1.4
Subtotal	2.0	3.2	5.4	6.2	6.5	7.9	8.0	7.6	8.3	8.0	7.8	6.6	4.2	2.4	3.2	3.4	3.4	3.6
Total	5.2	8.3	13.3	15.7	17.5	20.6	21.2	18.9	21.5	21.7	20.6	21.0	17.9	15.2	12.1	11.0	10.7	9.5
Latin America																		
Venezuela	2.9	3.5	3.7	3.6	3.2	3.4	3.0	2.4	2.3	2.2	2.2	2.4	2.2	2.1	1.9	1.8	1.8	1.7
Ecuador	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
Total	2.9	3.5	3.7	3.6	3.2	3.6	3.2	2.5	2.5	2.4	2.4	2.6	2.4	2.3	2.1	2.0	2.1	2.0
Africa																		
Libya	0.0	1.2	3.3	2.8	2.2	2.2	1.5	1.5	1.9	2.1	2.0	2.1	1.8	1.1	1.2	1.1	1.1	1.1
Algeria	0.2	0.6	1.0	0.8	1.1	1.1	1.0	1.0	1.1	1.2	1.2	1.2	1.0	0.8	0.7	0.7	0.6	0.6
Nigeria	0.0	0.3	1.1	1.5	1.8	2.1	2.3	1.8	2.1	2.1	1.9	2.3	2.1	1.4	1.3	1.2	1.4	1.5
Gabon	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	0.2	2.1	5.5	5.2	5.3	5.5	5.0	4.5	5.3	5.5	5.3	5.8	5.0	3.5	3.3	3.2	3.3	3.3
Asia																		
Indonesia	0.4	0.5	0.9	0.9	1.1	1.3	1.4	1.3	1.5	1.7	1.6	1.6	1.6	1.6	1.3	1.3	1.5	1.3
Total OPEC	**8.7**	**14.3**	**23.4**	**25.3**	**27.1**	**31.0**	**30.7**	**27.2**	**30.7**	**31.3**	**29.8**	**30.9**	**26.9**	**22.7**	**18.9**	**17.6**	**17.6**	**16.0**

*Production data are shown for current OPEC members regardless of when they became members. Neutral Zone production divided between Saudi Arabia and Kuwait. Columns may not add due to rounding.

Source: Energy Information Administration.

with demand and support the high prices. From 1980 through 1985, the reduction in OPEC output came disproportionately from the Middle East OPEC countries.

OPEC crude oil production, which was about 31 MMB/D in 1979, was deliberately reduced in a series of steps to 16 MMB/D in 1985 to keep world supply and demand in balance and maintain prices. Saudi Arabia accounted for much of the decrease, reducing its production, which had reached about 10 MMB/D in 1980 and 1981, to only 5 MMB/D in 1983, and to less than 3 MMB/D for several months in 1985. Continuation of then-current trends of falling demand and rising non-OPEC production would have led to further erosion of Saudi Arabian and OPEC production during 1986. The Saudis, in September 1985, decided to increase their production and market share rather than suffer further reductions. Late in 1985, OPEC concurred with Saudi policy to preserve market share. The resulting imbalance in supply and demand, heightened by the psychological impact of Saudi Arabia's abandonment of its balancing role, led to tumbling oil prices early in 1986.

In December 1986, OPEC agreed to production quotas through the first half of 1987 and a return to fixed prices in the range of $18 per barrel. By the end of 1986, spot crude oil prices had risen to about $18. It is uncertain whether the agreement will be continued after mid-1987.

Table 49 compares the populations, crude oil reserves, production, and excess crude oil productive capacity of the OPEC countries with the rest of the non-communist world. OPEC has 77 percent of non-communist oil reserves (68 percent of total world), and 83 percent of OPEC reserves are in Middle East OPEC countries. Middle East OPEC, other OPEC, and non-OPEC crude oil production is shown in Figure 52. The figure shows historical data for 1960–85 and NPC survey results for the upper price trend from 1990–2000.

NON-OPEC SUPPLY

Table 50 is a history of non-OPEC crude oil production from 1960, by major producing country and by continent. Total non-OPEC production was 9 MMB/D in 1960 and increased to about 15 MMB/D in 1970. About 4 MMB/D of the increase in non-OPEC production over that period was in the United States, Canada, and Latin America. The United States, although a net importer, was operating at less than capacity during this period because of prorationing.

From 1970 through 1976, total non-OPEC crude oil production changed little. U.S. production reached a peak of 9.6 MMB/D in 1970, then declined to 8.1 MMB/D in 1976. Although worldwide drilling activity increased after 1973,

TABLE 49

OPEC AND NON-OPEC POPULATION AND CRUDE OIL PRODUCTION CAPABILITY

	Population (Millions)	Crude Oil Reserves (Billion Barrels)	1985 Crude Oil Production (MMB/D)	Excess Capacity (MMB/D)
Arab Gulf*	15	300	5.9	8
Iran/Iraq	60	92	3.6	1
Other OPEC	315	83	6.5	2
Total OPEC	**390**	**475**	**16.0**	**11**
Other Non-Communist	2,960	144	22.7	0
Total Non-Communist World	**3,350**	**619**	**38.7**	**11**

*Saudi Arabia, Kuwait, United Arab Emirates, Qatar, and Neutral Zone.

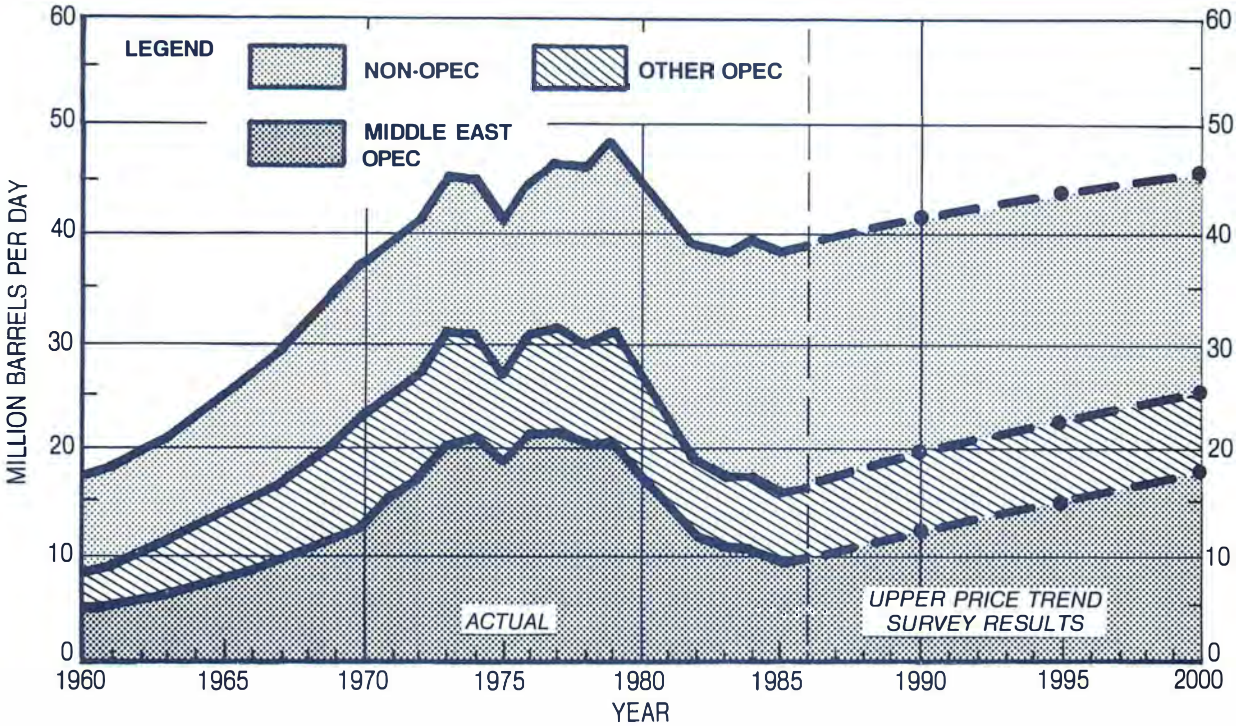


Figure 52. Non-Communist World Crude Oil Production.

NOTE: The survey collected data for the years 1990, 1995, and 2000. Trend lines are drawn through the survey data points.

it was several years before the results of this drilling markedly affected production.

By 1977, the response of increased drilling to higher prices since 1973 and the development of discoveries made in the late 1960s and early 1970s began to have a significant impact on non-OPEC crude oil production. Production increased by an average of 1 MMB/D per year from 1976 through 1985, from slightly over 14 MMB/D to nearly 23 MMB/D. United Kingdom production rose from zero in 1975 to 2.5 MMB/D in 1985. Mexican production increased from 0.8 MMB/D in 1975 to 2.7 MMB/D in 1985. The U.S. production decline was reversed, with output increasing from 8.1 MMB/D in 1976 to 9.0 MMB/D in 1985. Although drilling activity has been declining since 1982, the development of discoveries made during the 1979-82 period, when drilling was at all time high levels, has contributed to the increases in production in the last several years.

WORLD CRUDE OIL RESERVES AND RESOURCES

Total world proved crude oil reserves as of year-end 1985, including communist areas, were 700 billion barrels, as shown in Table 51. Middle East OPEC has 56 percent of total world crude oil reserves and 63 percent of non-communist reserves. OPEC's reserves were 475 billion barrels, 77 percent of non-communist crude oil reserves. The United States has only 5 percent of non-communist world reserves, and North America, South America, and Western Europe combined have only 23 percent.

A number of estimates of worldwide undiscovered recoverable resources of crude oil have been published. In recent years, the typical mid-range estimate has been about 1 trillion barrels for the entire world, with 25 to 50 percent in the Middle East. The estimates are based upon probabilities of occurrence of crude oil in known geological basins.

The Middle East, in addition to its large reserves, has other significant advantages over non-OPEC producing countries, particularly the United States. The Ghawar field in Saudi Arabia is the world's largest oil field—at 83 billion barrels of reserves—several times the size of total U.S. reserves of 28 billion barrels. The Ghawar field can produce at 5.5 MMB/D from only 332 wells, an average of 16,600 barrels per day from each well. Total U.S. production of 9.0 MMB/D comes from 647,000 oil wells, an average of 14 barrels per day. About 460,000 of these wells are stripper wells averaging about 3 barrels per day. The remaining wells average about 41 barrels per day.

The Burgan field in Kuwait is the world's second largest field, with 70 billion barrels of reserves. This field has produced at 1 MMB/D

TABLE 50

NON-OPEC CRUDE OIL PRODUCTION
(Million Barrels Per Day)

	1960	1965	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
North America																		
United States	7.0	7.8	9.6	9.5	9.4	9.2	8.8	8.4	8.1	8.3	8.7	8.6	8.6	8.6	8.7	8.7	8.9	9.0
Canada*	0.5	0.8	1.3	1.4	1.5	1.8	1.7	1.4	1.3	1.3	1.3	1.5	1.4	1.3	1.3	1.4	1.4	1.5
Total	7.6	8.6	10.9	10.8	11.0	11.0	10.5	9.8	9.4	9.6	10.0	10.1	10.0	9.9	9.9	10.1	10.3	10.5
Latin America																		
Mexico	0.3	0.3	0.5	0.5	0.5	0.5	0.6	0.7	0.8	1.0	1.2	1.5	1.9	2.3	2.8	2.7	2.8	2.7
Others	0.6	0.8	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.2	1.2	1.3	1.3	1.3	1.4	1.5	1.6
Total	0.9	1.1	1.5	1.6	1.6	1.6	1.7	1.8	1.9	2.1	2.4	2.7	3.2	3.6	4.1	4.2	4.3	4.3
Western Europe																		
United Kingdom	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.8	1.1	1.6	1.6	1.8	2.1	2.3	2.5	2.5
Norway	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.6	0.7	0.8
Others	0.3	0.4	0.4	0.4	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4
Total	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.8	1.3	1.7	2.3	2.4	2.6	2.9	3.3	3.6	3.8
Middle East	0.1	0.1	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.7
Africa																		
Egypt	0.1	0.1	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.9
Others	0.0	0.0	0.2	0.2	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7
Total	0.1	0.1	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.3	1.5	1.6
Far East and Oceania	0.1	0.2	0.5	0.7	0.8	0.9	0.8	0.9	1.0	1.0	1.1	1.3	1.2	1.2	1.3	1.5	1.7	1.9
Total Non-OPEC	**9.0**	**10.5**	**14.5**	**14.5**	**14.8**	**14.7**	**14.4**	**14.2**	**14.3**	**15.4**	**16.6**	**17.7**	**18.3**	**18.9**	**19.9**	**20.8**	**22.0**	**22.7**

*Includes tar sands.

Source: Energy Information Administration. Columns may not add due to rounding.

TABLE 51

PROVED RESERVES OF CRUDE OIL AT YEAR-END 1985 (Billion Barrels)

United States	28
Canada	7
Mexico	49
North America	84
South America	35
Western Europe	26
Africa	57
Middle East*	398
Far East and Oceania	19
Non-Communist World	619
Eastern Europe, U.S.S.R., China	81
Total World	**700**

*Middle East OPEC reserves are 392 billion barrels, and total OPEC reserves are 475 billion barrels.

from 390 wells, an average of 2,600 barrels per day. Saudi Arabia's Safaniyah field is the world's largest offshore field, with reserves at 32 billion barrels. This field has produced at 1.5 MMB/D from 188 wells, an average of 8,000 barrels per well per day.

There are many large fields with highly productive wells in the Middle East. The map at the end of this chapter shows the location of the major fields and their proximity relative to the Soviet Union. The map was prepared in 1984 and is included for illustrative purposes. Several major construction projects have been completed since then and others are underway or planned.

The map also shows the location of the Strait of Hormuz in the Persian Gulf, where a blockade of the Persian Gulf would most likely occur. The map also shows the Suez Canal and the Gulf of Aden, other locations where military actions could cause disruptions of oil supplies. Pipelines carrying Middle East oil to the Mediterranean and the Red Sea are also vulnerable to attack.

Because the Middle East contains 63 percent of non-communist world reserves and potentially a large portion of undiscovered resources, increasing dependence upon this volatile area by the non-communist world is inevitable. The challenge to the United States and the rest of the world is to manage this dependence to minimize economic and military vulnerability.

FUTURE NON-OPEC PRODUCTION

Major production declines are probable in the United States and in the North Sea as annual reserve additions in those areas fall below annual production. Both areas have shown large increases in reserve additions thus far in the 1980s, but drilling has dropped to much lower levels in 1986 because of the fall in world oil prices. The NPC Oil & Gas Outlook Survey, reported in Chapter Five, shows that survey respondents believe that non-OPEC reserve additions and production will decline with either of the two price trends considered in the survey.

The survey results are shown in Table 52 for non-OPEC supplies. The survey respondents believed that U.S. production would decline faster than other non-OPEC production. The survey shows that non-OPEC production, excluding the United States, increases through 1995 in the upper price trend, but declines continuously in the lower price trend. U.S. production is shown to decline continuously with either trend. These results reflect the high cost of finding and developing oil in the United States and the fact that the country has been extensively explored. Few large fields remain to be discovered except in frontier areas.

If oil prices remain at low levels, it is possible that some non-OPEC governments may offer better terms to exploration and development companies. Governments may be willing to reduce their levels of ownership in new projects or provide tax holidays or other incentives. Governments active in the North Sea, such as the United Kingdom and Norway, are possible candidates for putting together more attractive deals, and some concessions were made in 1986.

A small but significant portion of non-communist world oil supply consists of imports from communist countries, including China and the Soviet Union. These countries need to export oil to generate hard currency for certain imports, including grains, machinery, and technology. However, the NPC surveys show non-communist world imports of oil from communist countries declining from 1.8 MMB/D in 1985 to 0.8 MMB/D in 2000. Net communist exports could be higher if the Soviets increase the rate at which they substitute natural gas for oil internally.

Imports of oil from the Western Hemisphere and from Western Europe are considered to be more secure than supplies from most other areas. The governments of the North Sea countries and the North American continent are considered to be more stable than governments in the Middle East and Africa. Over time, these

TABLE 52

SURVEY REPONSE
NON-OPEC CRUDE OIL AND NATURAL GAS LIQUIDS PRODUCTION*
(MMB/D)

	Actual 1985	1990	1995	2000
Upper Price Trend				
United States	10.6	9.4	8.3	7.5
Other Non-OPEC Countries	14.6	15.3	15.6	15.0
Total Non-OPEC Supply	**25.2**	**24.7**	**23.9**	**22.5**
Lower Price Trend				
United States	10.6	8.4	6.7	5.5
Other Non-OPEC Countries	14.6	14.0	13.7	13.1
Total Non-OPEC Supply	**25.2**	**22.4**	**20.4**	**18.6**

*Excludes tar sands, shale, and other synthetics.

situations could change. Future governments in Canada, Mexico, or other countries could become reluctant to export oil to the United States, or may have less oil available for export.

During the 1970s, Canada reduced its exports of crude oil from the interior provinces to the United States in order to reduce the dependence of the eastern provinces on imports of overseas crude oil. Exports to the United States fell from 820 MB/D in 1975 to 360 MB/D in 1978, and were kept at about that level through 1981. Since then, exports have grown and in 1985 averaged about 700 MB/D.

Diversification of supply probably is a better strategy than depending upon one or two neighboring countries. However, because of the international nature of the world oil market, diversification of import sources will not insulate the United States from a price-induced energy crisis.

From the standpoint of protecting supply routes, the rule is that the shorter the route the better. Again, Western Hemisphere sources and Western Europe would be favored over most other areas. The distance from Saudi Arabia to Galveston, Texas, around the Cape of Good Hope is 12,500 nautical miles, while the distance from the North Sea to the U.S. East Coast is 3,300 nautical miles.

FOREIGN DEMAND

Table 53 shows historical oil consumption for the non-communist world and regions including North America, Latin America, the Middle East, and Japan.

Consumption of oil in the non-communist world grew at very high rates prior to 1973; from 1960 through 1973, the average rate was 7.6 percent per year. Following the first oil price shock, demand declined for two years at about 1.5 percent per year and then began to increase at 3 percent per year through 1979. However, with the second oil price shock in 1979, demand began to fall again and declined through 1983 at about 3 percent per year. In 1984, consumption increased about 3 percent, but declined by about the same percentage in 1985.

Effects of the first oil price shock in 1973–74 were still being felt by the time the second oil price shock occurred, and the pressures of the second shock reinforced those arising from the first. Cars were still being downsized, regulations were in place in many countries relative to insulating houses and buildings, appliances had been made more efficient, and industries were still replacing old equipment with new, more efficient equipment. Because much of the capital stock turns over

TABLE 53

NON-COMMUNIST WORLD OIL CONSUMPTION*
(Million Barrels Per Day)

	1960	1965	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985
North America																		
United States	9.8	11.5	14.7	15.2	16.4	17.3	16.7	16.3	17.5	18.4	18.9	18.5	17.1	16.1	15.3	15.2	15.7	15.7
Canada	0.8	1.1	1.5	1.5	1.6	1.7	1.7	1.7	1.7	1.8	1.7	1.9	2.0	1.8	1.6	1.5	1.5	1.5
Total	10.6	12.7	16.2	16.7	18.0	19.0	18.4	18.0	19.2	20.2	20.6	20.4	19.0	17.9	16.9	16.7	17.2	17.2
Latin America	1.5	2.0	2.7	2.9	3.1	3.4	3.5	3.5	3.8	3.9	4.1	4.2	4.8	4.7	4.8	4.7	4.6	4.6
Western Europe																		
France	0.6	1.1	1.9	2.1	2.2	2.4	2.3	2.1	2.3	2.2	2.2	2.4	2.3	2.0	1.9	1.9	1.9	1.8
Italy	0.4	1.0	1.8	1.9	2.1	2.2	2.1	1.6	1.8	2.0	2.2	2.0	1.9	1.9	1.8	1.7	1.6	1.7
United Kingdom	0.9	1.5	2.1	2.1	2.2	2.3	2.1	1.9	1.9	1.9	1.9	1.9	1.7	1.6	1.6	1.5	1.8	1.6
West Germany	0.6	1.6	2.4	2.6	2.8	2.9	2.6	2.5	2.7	2.8	3.1	3.1	2.7	2.5	2.3	2.3	2.3	2.4
Other	1.3	2.4	4.1	4.2	4.6	4.7	4.6	4.6	4.9	4.9	5.0	5.2	5.0	4.8	4.5	4.4	4.2	4.2
Total	3.9	7.5	12.5	13.1	14.0	14.9	13.9	13.3	14.2	13.9	14.4	14.7	13.5	12.5	12.1	11.8	11.8	11.7
Middle East	0.5	0.7	0.9	1.1	1.1	1.3	1.3	1.3	1.4	1.5	1.6	1.8	1.9	2.1	2.2	2.3	2.5	2.5
Africa	0.4	0.6	0.7	0.8	0.9	1.0	0.9	1.0	1.1	1.2	1.3	1.4	1.5	1.5	1.7	1.7	1.8	1.8
Far East and Oceania																		
Japan	0.7	1.7	3.9	4.2	4.4	5.1	5.0	4.5	4.8	5.2	5.1	5.5	5.0	4.9	4.6	4.4	4.6	4.3
Other	0.8	1.3	2.2	2.4	2.6	2.8	2.8	2.8	3.2	3.5	3.7	4.0	4.0	4.0	4.0	4.1	4.2	4.3
Total	1.5	3.0	6.1	6.6	6.9	7.9	7.8	7.3	8.0	8.7	8.8	9.5	8.9	8.8	8.6	8.5	8.8	8.6
Total Non-Communist World	**18.3**	**26.5**	**39.4**	**42.5**	**45.1**	**47.6**	**47.5**	**46.2**	**47.4**	**50.2**	**50.6**	**52.0**	**49.6**	**47.4**	**46.3**	**45.5**	**47.0**	**46.4**

*Apparent consumption; Energy Information Administration data. Columns may not add due to rounding.

slowly, the effects of these changes will still be felt in the 1990s.

Changes in currency exchange rates and consumption taxes also have affected demand. Usually, crude oil prices are denominated in U.S. dollars. Because of the depreciation of currencies relative to the dollar in the early 1980s, the prices of oil in local currencies stayed high even though the oil price in dollars was falling, as shown in Figure 53. Some Western European countries and Japan increased consumption taxes on some petroleum products while crude oil prices were coming down. This also helped to keep the price to consumers high and reduced demand.

In some countries, government policies are bringing about the substitution of other fuels for oil. In the Soviet Union, natural gas is being substituted for oil in many uses including space heating and electricity generation. In Scandinavia, coal is being substituted for oil in similar applications. In France, a strong nuclear program is in progress, which will bring about generation of most of the country's electricity from fission.

The NPC survey included estimates of future U.S. and foreign oil consumption. Aggregate foreign demand for oil is shown to increase from 30.7 MMB/D in 1985 to 35 MMB/D in 2000 in the upper price trend case. Demand in the lower price trend case increases to 38 MMB/D in 2000. U.S. demand increases from 15.7 MMB/D in 1985 to 17.4 and 19.9 MMB/D in 2000 in the upper and lower price trends, respectively.

POLITICAL FACTORS

Just as certain events—wars, revolution, frenzied buying, psychological factors—have affected U.S. vulnerability to energy crises in the past, such events are likely to affect U.S. vulnerability in the future. Cooperation among OPEC members in reducing output to create supply deficits could contribute to future price shocks. Many foreign countries have very high debt levels. Defaults on loans by Mexico would have an unfavorable impact on Mexican oil development. Low oil prices jeopardize banks that have made a high proportion of energy loans.

Wars and revolutions also constitute a threat to non-communist world energy supplies. Any war or uprising, including terrorist attacks, that could bring about damage to major Middle East oil-producing areas would have an impact on supply and could possibly trigger a crisis. Another possibility is an embargo on shipments from the Middle East to a particular country or countries, similar to the Arab oil embargo of 1973. Embargoes are not generally effective because it is impossible to totally restrict flows from one area to another, but embargoes accompanied by production cutbacks can be effective. Embargoes also increase uncertainty about supplies and price and can trigger bidding wars and hoarding.

FOREIGN REACTIONS TO U.S. POLICIES

U.S. foreign policy is another factor that affects the nation's vulnerability. U.S. support of

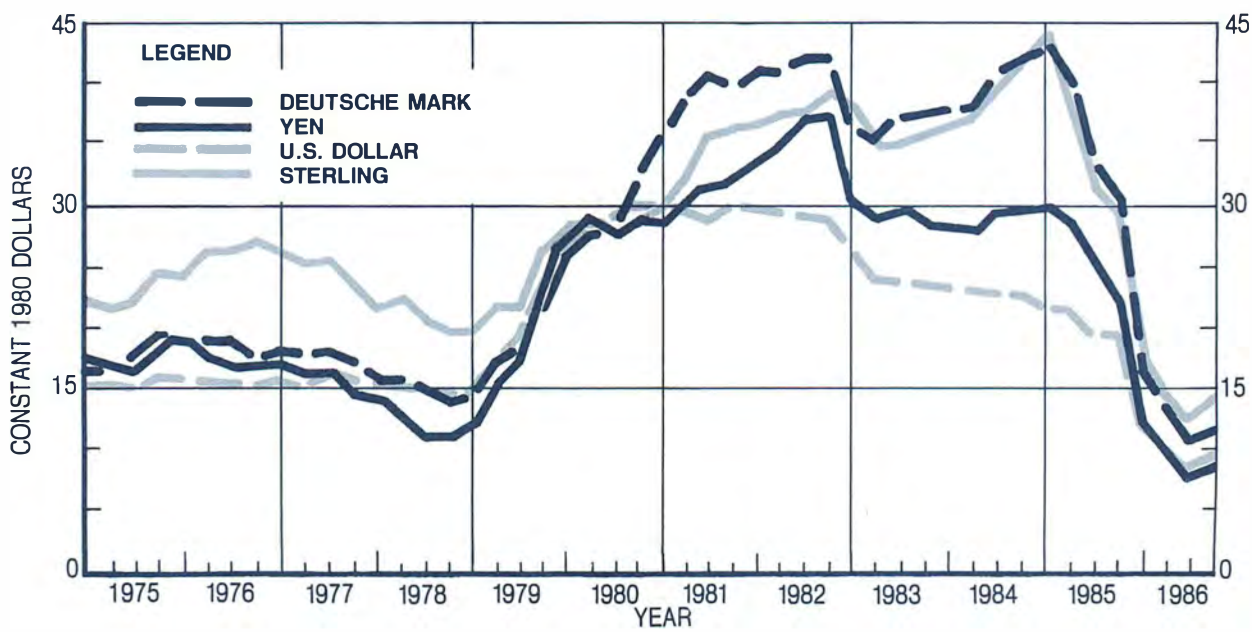


Figure 53. Purchase Price of Arabian Light Crude Oil--Selected Currencies.

Israel contributed to the Arab oil embargo in 1973. U.S. relations with Iran and Libya have been strained by the hostage crisis in 1980 and terrorist activities.

U.S. policies with regard to aid to certain countries such as Israel, Egypt, and Saudi Arabia tend to cause unfavorable reactions and increase tensions in some other foreign countries. Israel generally opposes U.S. aid to Arab countries and vice versa. Support of the Shah contributed to the anti-American feeling in Iran following the revolution.

SUMMARY OF INTERNATIONAL FACTORS

- The United States is dependent upon oil imports, and its dependence will increase in the future.
- The United States possesses only about 5 percent of non-communist world crude oil reserves, but in 1985 accounted for 23 percent of crude oil production and 34 percent of total oil consumption.
- Middle East OPEC countries have 63 percent of non-communist world crude oil reserves, and in 1985 accounted for 25 percent of crude oil production, most of which was exported.
- Middle East OPEC oil fields and wells are prolific. Oil wells typically produce several thousand barrels per day, compared to about 14 barrels per day for average U.S. wells.
- The oil crises of the 1970s were triggered by supplydisruptions initiated in the Middle East, and the oil price "collapse" in 1986 was also triggered by actions of Middle East OPEC countries. The tremendous reserves and prolific fields and wells of the Middle East OPEC countries vest those countries with the power to quickly create oversupplies or shortages and thereby create havoc in world oil markets.
- The volatile politics of the Middle East are likely to lead to future disruptions of oil markets.
- The industrialized world has reacted to higher oil prices by reducing consumption and initiating conservation.
- The non-OPEC oil and gas industry has reacted to higher oil prices by increasing exploration and oil and gas production.
- The current oil situation, characterized by oversupply and low prices, will lead to falling non-OPEC oil production and will rapidly increase non-communist world dependence on imports from Middle East OPEC countries, thereby increasing vulnerability to a supply disruption.

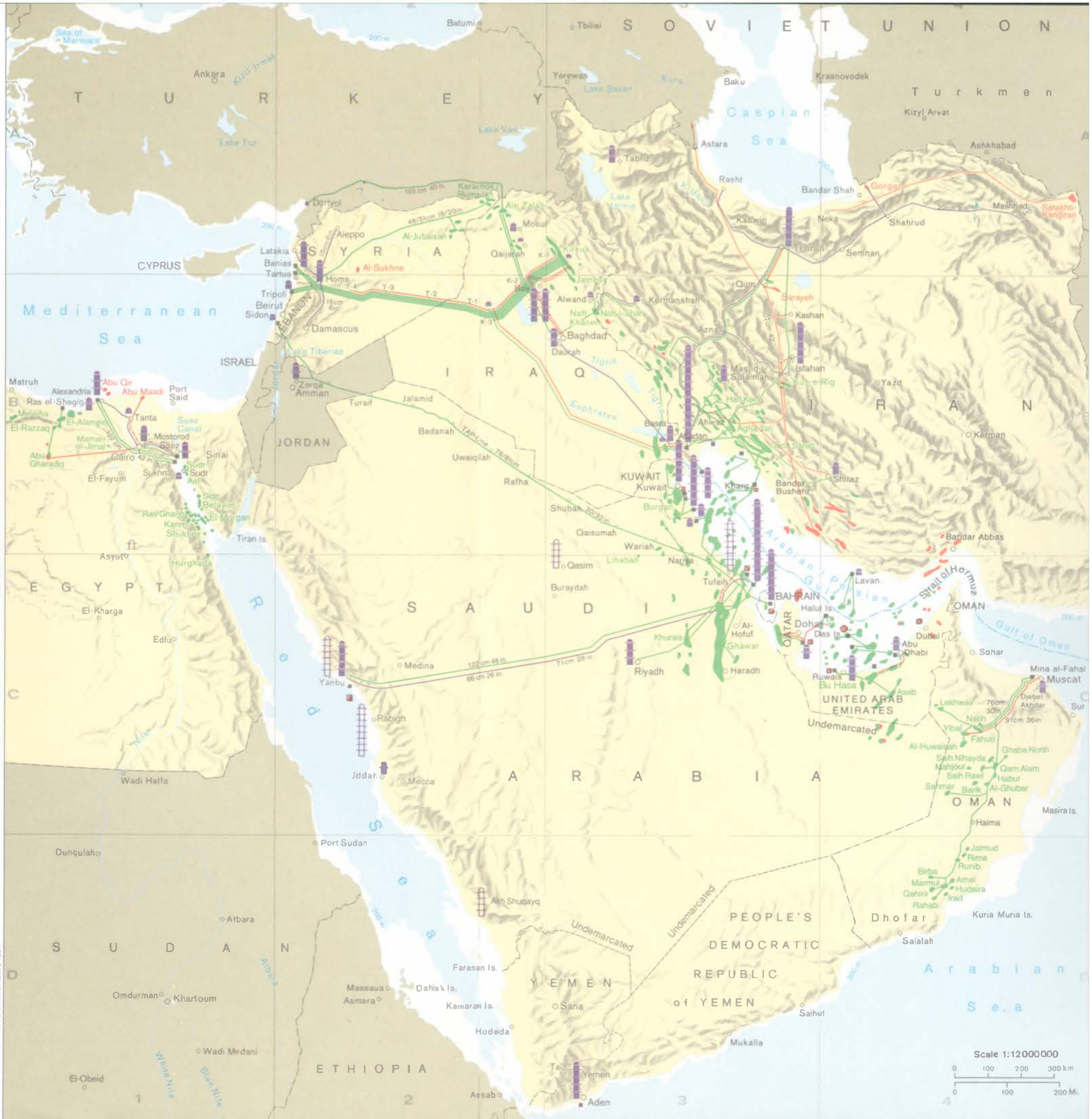
THE MIDDLE EAST

Legend

- Ghawar — Oil field or discovery
- Hassi-R'Mel — Gas field or discovery
- Crude oil pipeline
- Natural gas pipeline
- Natural gas liquids (NGL) or products pipeline
- Pipelines planned or under construction
- Refinery
- Refinery planned or under construction
- Tanker terminal or loading platform
- Liquefied natural gas (LNG) plant
- NGL plant
- International boundaries

Height of symbol corresponds to the annual crude capacity (1 division = 40,000 barrels daily = 2 million metric tons)

Some of the refineries, terminals and pipelines listed on these maps may be partially or totally inoperable due to war action or other reasons.



Section III

Policy Options

Chapter Nine

Policy Options

INTRODUCTION

Although all constituencies may not agree about what specific policy options for avoiding or mitigating vulnerability to future energy crises may be best, it is clear that there are basic guidelines that should apply to government policies. The industry believes that past lessons strongly suggest the need for stability and predictability in government actions.

Positive government energy policies that encourage, rather than discourage, domestic petroleum exploration and production will lead to a more stable, secure energy future for the United States. Tax incentives, decontrol of natural gas prices and markets, and opening unexplored federal lands to search for new large oil and gas fields are a few examples of such policies.

Environmental regulations should give consideration to the need to avoid or mitigate vulnerability to future energy crises in the evaluation of the cost and benefits associated with such regulations.

The appropriate role of government in the energy market should be limited and thoughtful. The government should strive to look at energy policy formation in the long term and within the context of broad public policy. In evaluating policy options, government should carefully weigh their efficiency in order to select the option, or combination of options, that provides the greatest reduction in oil import dependence at the least cost to the economy. Decisions made in this fashion would help provide a climate within which prudent business decisions can be made, and would benefit all Americans.

The options discussed in this chapter have been grouped into two categories: (1) those directed at reducing the United States' growing dependence on imported crude oil and products and (2) those intended to reduce the likelihood of an energy crisis and/or to mitigate its impact. The former group is further divided into options that act to increase domestic oil and gas supplies, by stimulating exploration and development activity, and options that act to reduce demand for oil and gas.

Although not specifically discussed, another option is a floor price to guarantee a minimum price to oil producers that would maintain reasonable production and reserve levels. The price floor could be financed through various methods, such as a consumption tax or an import fee, both of which are discussed below.

OPTIONS TO REDUCE DEPENDENCE ON IMPORTED OIL—STIMULATE OIL AND GAS SUPPLIES

The following policy options operate to increase U.S. oil and gas domestic reserves and production:

1. Encourage greater access to federal lands with potential oil and gas resources, onshore and offshore, and improve the lease terms under which such lands are offered.
2. Remove tax disincentives and use positive incentives to maintain existing production and to stimulate new oil and gas exploration and development activity.

3. Stabilize the price of oil by use of oil import fees at a level that will reduce consumption and stimulate domestic oil and gas production.
4. Promote research and development to increase the recovery of oil and gas already discovered, much of which cannot be produced economically with current technology, and to develop the longer range technologies required to produce alternative fuels.
5. Decontrol natural gas prices and markets by repeal of NGPA price controls on old gas, NGPA incremental pricing provisions, and the Fuel Use Act.

In the discussion of each of the options, the advantages and disadvantages peculiar to major options are presented in bullet format, but minor options are limited to a simple narrative. However, there are some general observations that apply to each of this first group of options:

- Stimulation of oil and gas exploration and development activities increases U.S. domestic supplies, which reduces the growth of U.S. oil import dependence and vulnerability to future energy crises and reduces the likelihood of future price shocks and economic dislocations.
- The most important reason to stimulate domestic oil and gas supplies and reduce dependence on imported oil is to protect the national security, both from an economic standpoint and to meet wartime mobilization requirements should the need arise.
- Increasing exploration and production activity in the United States will do much toward preserving the domestic oil field service and supply industry. This is an important consideration in determining the ability to respond to a supply disruption or to a need to increase production rapidly.
- The reduction of oil imports operates to reduce U.S. balance of trade deficits. In 1985, net payments for oil imports cost $45 billion, by far the single largest component of U.S. imports.
- Additional U.S. oil and gas production increases federal, state, and local revenues from income taxes, ad valorem taxes, severance taxes, and royalties.
- Government intervention in support of the industry cannot be expected to cease when the need for this support ends. As a result, interference in the industry's operations and pricing for the long term would become more likely.

Improve Access to Federal Lands

U.S. oil and gas exploration and production can be increased if the federal government takes actions to improve industry access to federal lands, onshore and offshore, and to eliminate moratoria and other delays on OCS leasing. The potential for oil and gas reserves on federal lands is considerable. However, exploration for and development of these reserves have been severely restricted by governmental land use legislation and policies.

Exploration began in federal waters off California in 1963 and has been quite successful. In all, about 2 billion barrels of oil have been found. Six fields of over 200 million barrels each have been discovered on the California OCS in the last 15 years. California offshore leasing, however, remains a major issue. A congressional negotiating team is meeting with the Department of the Interior, and leasing opponents continue to ask Congress, the state, and local jurisdictions to impose restrictions that would make it more difficult to lease and develop offshore lands.

In 1985, Congress enacted a moratorium on the leasing for oil and gas development for large portions of the OCS off California. This moratorium prohibited the leasing of 6,460 offshore tracts covering over 37 million acres, about 63 percent of the California OCS planning area. Although Congress did not officially extend the moratorium for fiscal 1987, it delayed the opening of bids for any California OCS lease sale until at least February 1, 1989. Estimates of the undiscovered oil and gas resources for this area range from 1.25 to 5 billion barrels. Peak production estimates range from 172 MB/D to 688 MB/D.

In U.S. onshore areas, 90 million acres of federal wilderness areas and 71 million acres of national parks and wildlife refuges have been closed to mineral leasing. Congressional leasing moratoria have placed an additional 95 million acres being considered for wilderness designation off-limits to leasing and exploration, even though this was not the intent of the original legislation. In total, 256 million acres of federal lands have been closed to oil and gas leasing, equivalent in area to Texas plus California.

Probably the most prominent onshore oil and gas prospect is the coastal plain of the Arctic National Wildlife Refuge (ANWR) in Alaska. Geologists believe this single, remote area contains the most significant amounts of oil and gas of any onshore region in the United States. Estimates of undiscovered resources within ANWR are comparable to Prudhoe Bay, which produces approximately 20 percent of the nation's domestic crude oil supply. Ninety-two percent of ANWR's 19 million acres would remain closed even if leasing were permitted. Of the remaining 8 percent of ANWR acreage in the coastal plain, only a fraction would ultimately be used for oil production.

Even if improved access to federal lands is allowed, the long lead times involved in exploring for and developing oil and gas reserves mean that production cannot be expected to begin until the mid to late 1990s. Nearly five years are projected for obtaining all the required permits and plan approvals, and completing exploration and delineation drilling. Another five years would be required for development drilling and the construction of facilities and pipelines.

In deciding whether to allow increased access to federal lands, onshore and offshore, the benefits of and national need for domestic oil and gas production must be weighed against the environmental risks. For onshore areas, such as the coastal plain of ANWR and the Rocky Mountains, the benefits of oil development should be weighed against disruption of only a small portion of the total area.

The issue here is not merely gaining access to more acreage. Rather, the issue is gaining access to promising prospects that could yield reserves and production that would significantly reduce U.S. dependence on oil imports. Only small areas of offshore California, the Rocky Mountains, and ANWR are highly prospective, and exploratory drilling would be largely confined to those areas. Improved technology and careful attention to environmental considerations make it possible to develop oil and gas production in a way that is compatible with multiple uses of areas both onshore and offshore.

Advantages

- Because of the pressing need to add new domestic oil and gas reserves, opening the most promising, highest potential areas first would help concentrate industry investment in prospects where new oil and gas production could be the greatest.
- Accelerated leasing and land access in areas such as offshore California, the Rocky Mountains, and the Alaskan North Slope, where there are existing oil production and transportation facilities, would help reduce the long lead times involved in the development process.
- Removal of leasing moratoria and land restrictions will stimulate economic activity.

Disadvantages

- Oil and gas development may conflict with land-use goals for federal lands.
- Drilling rigs operating in OCS waters can conflict with the aesthetics of scenic ocean vistas, particularly offshore California.
- Offshore oil spills could disrupt portions of the marine habitat of endangered species.
- Development in the Arctic could disturb the migrating patterns of certain wildlife.

Enhance Federal Leasing Policies

The leasing, exploration, and development of federal oil and gas lands could be facilitated by changes in the lease terms. Among the possible changes are reducing minimum bonus bids and rentals, extending lease terms, reducing royalties, and exploring alternative methods to awarding leases, such as work commitments and royalty or profit-share bidding. At current oil price levels, reduced minimum bids and alternative methods of awarding leases may be appropriate measures to conserve industry capital and enhance the economic viability of exploration on the OCS. Reducing rentals and lengthening lease terms will prevent premature abandonment of federal leases, and will allow drilling schedules to be determined by economic considerations. Reducing royalties would prolong the life of existing fields, lower the threshold volumes required to justify development of new fields, and thereby increase oil and gas production.

The leasing of federal lands has been a significant source of revenue for the government. Through 1983, the federal government had collected $68 billion from lease bonuses and oil and gas royalties from OCS lands, which was 54 percent of the total cumulative value of oil and gas production from these lands. Reduced bonus bids, royalties, and rentals would, however, reduce federal revenues to the extent that they are not offset by higher tax revenues from increased or extended production. In addition, royalty and profit share bidding could result in delays in exploration and development activities and would reduce industry's motivation to develop new technology.

Provide Incentives to Encourage Exploration and Production

Changes in federal, state, and local tax codes could be used to encourage the exploration and production of U.S. oil and gas reserves. These initiatives could either remove existing disincentives to exploration and production activity or provide new incentives for such activity. These new incentives could favor capital-intensive business in general, the petroleum industry in particular, or at the extreme, be highly targeted to preserve existing marginally economic production. In addition, non-tax policy initiatives could be used to encourage additional exploration and production activity or preserve existing production.

According to the Joint Committee on Taxation, in recent years the oil industry has had effective tax rates considerably higher than the average for all U.S. industry. When the Windfall Profit Tax is taken into account, the oil industry's effective tax rate has been the highest of any U.S. industry. Calculations by the American Petroleum Institute indicate that for the 1980–85 period, the petroleum industry's effective tax rate, including the Windfall Profit Tax, averaged 65 percent higher than the average for all industry.

Remove Existing Disincentives

Actions that would mitigate existing disincentives to petroleum exploration and production include:

1. Allowing the immediate expensing of 100 percent of intangible drilling costs in calculating federal income tax liability and expanding definition to include geological and geophysical costs and unrecovered surface casing. The Tax Reform Act of 1986 requires that major oil companies defer recognition of 30 percent of these costs. Based on 1985 data, this provision would expose about $6 billion of industry cash flow to earlier taxation.
2. Relaxation or removal of the 50 percent-of-net-income limitation on percentage depletion. Percentage depletion deductions, which are still available to independent oil companies but not to majors, may not exceed 50 percent of a company's net income. In times of low prices and meager earnings, this limitation substantially reduces the intended cash flow benefit from percentage depletion.
3. Removal of oil and gas preference items from alternative minimum tax computation.
4. Reduction of state severance taxes on petroleum extraction. Currently, states collect a percentage of wellhead revenue ranging to more than 12 percent, regardless of profitability. In 1985, petroleum industry severance and exploration and production property tax payments totaled $6.5 billion. In 1986, this figure is estimated at about $4 billion.
5. Repeal of the Windfall Profit Tax. Although essentially inoperative in times of depressed oil prices, this excise tax on revenue has siphoned $68 billion from the industry plus another $10 billion from royalty owners since its imposition in 1980. Existence of the tax dampens prospects for future cash flow rejuvenation from price increases, rendering current investments less attractive. It also imposes a significant accounting and reporting burden on oil firms.

Provide New Incentives

Actions that would provide new incentives for exploration and production activity include:

1. Providing an Investment Tax Credit including credits for research and exploration activity. The recent repeal of the investment tax credits has been estimated to reduce petroleum industry cash flow by $4.5 to $6.5 billion through 1991.
2. Restoring industry-wide percentage depletion at a 27.5 percent rate.
3. Enacting more rapid asset depreciation schedules.
4. Providing a price guarantee for domestic oil and gas discovered and produced after a specified date. The price guarantee, possibly financed by a consumption tax, would have to be high enough to make exploratory drilling attractive. The price could be guaranteed for oil and gas produced in the future from new fields discovered after the legislation is passed. If the actual price of oil and gas is above the guarantee level, the government would pay nothing. Even if market prices are below the guarantee level, the exposure of the government would be limited because only successful, newly discovered oil and gas fields would be covered. This guaranteed future price would represent an incentive price floor for new oil.
5. Restoring prior law treatment of taxes paid to foreign governments. Restrictions recently imposed on foreign tax credits reduce petroleum industry cash flow by an estimated $2 to $3 billion through 1991.

In a period of depressed prices, the cost of production for low volume "stripper" wells, heavy oil, and enhanced recovery operations may equal or exceed the price received, resulting in out-of-pocket losses or shut in of that production. Once shut in, many wells cannot be economically reactivated (due to mechanical and/or reservoir deterioration) even at dramatically higher price levels. Many of the actions noted above could be specifically targeted to sustain marginal production. Other measures that could be considered include outright grants per barrel of production and non-interest-bearing, volume-related loans with repayment obligations and timing tied to escalation of oil prices.

Advantages

- Removing existing disincentives and providing new incentives through the tax code would encourage exploration and development activity. At the same time, reducing the oil industry's tax burden would improve current and expected future cash flow, thus providing internally generated funds to finance investments and attracting external funds.
- Unlike tariffs, use of the tax code to provide incentives for petroleum exploration and production would not impair the international competitiveness of U.S. manufacturers.
- Capital-intensive industries in general are penalized by the U.S. tax system's bias toward consumption and against investment. Restoring the Investment Tax Credit, accelerating depreciation deductions, and providing other investment incentives would lessen this bias. Such measures would help stimulate petroleum exploration and production activity by reducing taxes and increasing investment incentives.
- Policies designed to support existing marginal production would have a measurable immediate and continuing effect on the availability of domestic oil, would help sustain the oil field service industry, and would permit recovery and utilization of proven petroleum reserves that might otherwise be foregone. More than 4 billion barrels of proven reserves are associated with stripper production.

Disadvantages

- Preferential tax treatment for any particular industry would distort investment decisions, preventing capital from flowing to its most efficient use. This would violate the goal of neutral tax impact widely endorsed during the recent tax reform debate.
- Providing incentives for domestic production when less expensive imports are available is an imprudent "drain America first" strategy.
- It may be more cost effective and economically efficient to use the public funds to expand strategic stockpiles rather than to promote exploration and production activity.
- A reduction in tax payments by the oil and gas industry would require tax increases elsewhere, reduced funding of other programs, or the acceptance of a higher federal budget deficit, which would result in higher interest rates, a stronger dollar, and a worsened trade deficit.
- Targeting stripper wells or other marginal oil production for special incentives would arbitrarily discriminate against other existing or prospective production. It would be more efficient and cost effective to allocate the funds involved to support new exploration activities if the combined cost of finding, developing, and producing new reserves were expected to be less than the cash operating cost of marginal production.
- Tax incentives are effective only for recipients who are paying taxes.

Enact an Oil Import Fee

An approach to reducing U.S. dependence on imported oil is through enactment of an oil import fee—a tariff on imports of crude oil and petroleum products. An oil import fee would stimulate domestic energy production while simultaneously reducing energy demand, in particular oil demand. But the fee would also impose economic costs on the U.S. economy, in terms of increased inflation and reduced economic growth and international competitiveness. The benefits of reduced import dependence and diminished vulnerability to an oil supply disruption must be balanced against these costs when evaluating any proposal for an oil import fee.

An import fee could be either a fixed fee or a variable fee that phases out when world oil prices reach a target price. A fixed fee would be set at a specific amount per barrel. A variable fee would equal the difference between a target crude oil price and the price of imported oil, thus raising the import price to the target level.

An oil import fee would raise the U.S. price of imported oil, and with it the price of domestic oil. Natural gas prices and, to a lesser extent, the prices of other U.S. energy supplies would also rise, although not necessarily in proportion to the oil price rise.

Any import fee would need to be imposed on both crude oil and refined petroleum product imports, otherwise import patterns would immediately shift toward products only. Such a shift would not only be detrimental to the domestic refining industry, but could also completely negate the objectives sought by the tariff on crude oil.

Advantages

- Energy security would be enhanced by lowering import dependence and vulnerability to future supply disruptions, through both increased domestic production and conservation created by the higher price. By 1990, imports would be reduced by 26 percent by a fee that would raise the crude oil price from the NPC survey lower price trend to the upper price trend. Such a fee would defer a 50 percent dependence on foreign oil by five years, until about 1995. A larger fee could postpone a 50 percent dependence to a later date.
- Price stability at an adequate level, which may be achieved through a variable oil import fee, would encourage domestic producers to continue exploration and development in high cost, high-reserve-potential areas, including frontier areas such as Alaska and the deep water U.S. Outer Continental Shelf. These areas are believed by the USGS to contain 35 billion barrels of oil, an amount equal to the total oil reserves added in the United States during the last 15 years.
- Over 100,000 stripper wells, producing in total as much as 250,000 barrels of oil per day, could be maintained. Once plugged, the reserves from these marginal wells could be permanently lost.
- An oil import fee would raise significant revenue for the federal government. This revenue would come from the fee on foreign imports, increased income taxes from domestic producers, and increased federal royalties. In addition, increased state income and severance taxes could be generated.
- An import fee would increase exploration and production activities, would rejuvenate the petroleum industry service sector, and would restore a portion of the 229,000 jobs lost in that sector from 1982 to December 1986.
- An import fee would strengthen the balance sheets of many "problem banks" with oil sector loans, minimizing the federal government's continued bailout of failed banks.
- A simple fee could be imposed using the existing duty payment process administered by the U.S. Custom Service. (A very small tariff is already imposed, 10.5 cents per barrel on crude oil and 52.5 cents per barrel on petroleum products—exclusive of Superfund.) Thus, establishment of a new bureaucracy could be unnecessary.

Disadvantages

- An import fee would have an immediate impact by raising the inflation rate and reducing GNP. This reduction in activity would cause a decline in corporate and individual income taxes collected from non-energy companies and their employees. This could ultimately offset the increase in taxes collected from the oil industry.
- Areas with no oil production, but a heavy dependence on fuel oil, would be adversely impacted by an oil import fee, which would be perceived as inequitable and politically troublesome.
- Enactment of an oil import fee would cause difficulties between the United States and its trading partners. It would violate the U.S. commitment under the General Agreement on Tariffs and Trade, as well as bilateral agreements with Canada and Venezuela. Mexico and Canada could be impacted if U.S. imports declined significantly, impairing both countries' ability to reduce foreign debt. Exemptions to "favored nations" or selected products would greatly reduce the effectiveness of the fee as a revenue contributor and as a mechanism for raising domestic oil prices.
- If the fee on petroleum products was not set in proper relation to the fee on crude oil, inequities among individual producers and refiners would be created. This could lead to a perceived need for select exemptions and the entitlements. The experience with the entitlements program in the 1970s is especially instructive here.
- If a similar fee is not placed on imported natural gas, Canadian and Mexican gas imports would be stimulated, which

would reduce the effectiveness of the fee in stimulating domestic gas production.

- Many key U.S. industries dependent on oil and natural gas, e.g., agriculture and petrochemicals, would be competitively disadvantaged in domestic and foreign markets.
- An oil import fee could evoke trade retaliation by the major oil-producing countries.
- Enactment of a variable fee, or any fee complicated by exemptions, would require establishment of a new bureaucracy. Even a simple fee could require additional bureaucracy to prevent potential evasion.

Encourage Research and Development Activities

Efficiencies in exploration and development as well as increased recoverability historically have been and can continue to be aided through targeted research and development. Research and development can be supported and encouraged by the government in both the public and private sectors through direct grants and appropriate tax incentives.

The amount of publically supported oil and gas research is small relative to public research support in other energy areas. The current low oil and gas prices have resulted in a reduction of private research and development in areas of oil and gas supply and demand, with little likelihood of restoration or increases in the near future. As research and development activities are investments in the future, the impact of lessened activity today will compound problems later.

The U.S. resource base in oil and natural gas is substantial, both for new discoveries and for increased recovery from existing reservoirs. But the resource base is marginal, and converting it to reserves is a relatively high cost proposition. Most reserves in the United States must be developed in small increments or from remote frontier areas. Although marginal, the U.S. oil and gas resource base is substantial and particularly amenable to development cost reductions arising from research activities.

Advantages

- A research and development support program by the government in all aspects of oil and gas extraction could enhance the recoverability of already discovered and potential U.S. reserves that would otherwise be unrecoverable.
- Government aid, in the form of grants and direct research, could help sustain the research effort in developing synthetic fuels that would yield significant benefits later on.
- Publication requirements associated with government-sponsored research projects would result in dissemination of information throughout the industry. This would be particularly helpful to the small operators who do not have access to privately funded research.
- A government support program, if implemented soon, would maintain some parts of skilled research teams that would otherwise break up or go into other fields of work.
- Cooperative research projects conducted by a group of companies, permitted under the limited antitrust protection given by the 1984 Cooperative Research Act, would eliminate duplication of effort and promote cross-fertilization of ideas, and thus enhance the prospects of earlier commercialization of research results.

Disadvantages

- The results of government-sponsored research are in the public domain, which makes them less desirable for a company whose main focus is on proprietary research. This might make some companies reluctant to participate.
- Cooperative research, encouraged by the government, might tend to eliminate the diversity of approach and quality of results that come from the individual company research efforts. To avoid this, government-supported activities should complement private efforts.
- Government-subsidized, large-scale demonstration projects are commonly ineffective; government support of projects at the research and development level are more appropriate.

Decontrol Natural Gas Prices and Markets

Decontrol of natural gas field prices, repeal of the incremental pricing provisions of the Natural Gas Policy Act of 1978, and repeal of the provisions of the Fuel Use Act prohibiting the use of natural gas as a primary fuel for new power plants and major fuel burning installations would promote the development and production of gas that would not otherwise be available and would create a more efficient energy market.

Interstate sales by producers have been regulated since the 1954 Phillips decision of the U.S. Supreme Court. The NGPA extended price controls to intrastate sales. On January 1, 1985, the NGPA removed controls on about half of the gas being produced. However, over 20 categories and subcategories of old gas remain under permanent price ceilings.

The Department of Energy has estimated that complete decontrol of natural gas field prices would provide an additional 30 to 34 TCF of natural gas supplies, an increase of about 20 percent in gas reserves in the lower 48 states. Market prices for this natural gas would permit existing wells to produce longer by lowering abandonment pressures, would improve the economics of well stimulations and workovers, and would encourage "infill" well drilling in old fields—the drilling of additional wells between existing wells for more efficient recovery.

The DOE estimate of additional gas reserves added through price decontrol is approximately twice the current annual natural gas production rate. These additional supplies would make it possible to raise natural gas production rates by around 1.5 TCF per year, eliminating the need for approximately 750 MB/D of crude oil imports.

The NGPA also contains incremental pricing provisions designed to discipline interstate pipelines in their gas purchasing practices. These regulations require the pipelines to include in the gas price to large industrial boiler fuel users gas purchase costs that exceed specified threshold levels. The prices for these users cannot exceed the price level established by FERC, based on alternative fuel costs. FERC has set this price at a residual fuel oil price level. Consequently, since this ceiling approximates the current market price for natural gas, the incremental pricing provisions are not currently impacting the price of natural gas for these users. However, a future commission could set natural gas prices higher for large industrial boiler fuel users.

The Powerplant and Industrial Fuel Use Act, also enacted in 1978, was designed to shift electric utility power plants and major industrial fuel-burning installations from oil and gas to coal and renewable energy sources. The Act prohibits the use of natural gas and oil in new electrical utility power plants and some new large industrial facilities. The Act empowers the Secretary of Energy, upon petition, to grant temporary and permanent exemptions from the prohibition for a set of site-specific situations. Exemptions for cogeneration facilities have been common, and several proposals to construct major utility-owned, gas-fired generating facilities under exemptions are actively being pursued.

Advantages

- Allowing all natural gas to achieve free-market prices would result in significant long-range increases in gas supplies that could be developed and produced over the next 10 to 20 years.
- These additional gas supplies would create downward pressures over time on prices of natural gas and competing fuels, keeping prices lower than they might otherwise be.
- The additional gas produced over time from old fields would require few new downstream facilities; thus this supply could reduce the average unit transportation cost of gas delivered to consumers.
- More work in fully developing old gas fields would provide jobs for American workers and boost local economies.
- Total decontrol of natural gas markets would send proper price signals through the economy, which would allow faster responses by producers and consumers alike to changes in energy prices, which would moderate the cycles of oversupply and shortage.
- Total price decontrol would reduce federal, state, and industry administrative costs.
- Repeal of NGPA incremental pricing (a program that is not currently operative) would remove possible future discrimination against boiler fuel users of interstate gas, permitting equal costs for competing companies in the same industry.
- Projections of U.S. electricity demand growth, when compared with the new generating capacity currently under construction or identified in utility plans, indicate that a significant amount of new capacity will have to be provided during the 1990s from initiatives that are not yet identified. Although combined-cycle power plants fired primarily by natural gas would be attractive options for a portion of this capacity, the exemption procedure of the Fuel Use Act, particularly for proposals that will be initiated several years in the future, adds significant uncertainties to an already uncertain planning environment, and reduces the attractiveness of the gas option.

- Natural gas is an extensive domestic resource, efficient, cost effective, and environmentally desirable, and it has an inherent capability to maintain diversity in the mix of fuels to meet national energy requirements. Increased diversity improves the reliability of the energy system in response to failure of any individual energy supply source.
- Greater use of gas to serve the increasing fuel requirements of electric utilities would compensate for gas market loss in the energy-intensive manufacturing industries arising from restructuring of the U.S. industrial base.
- Increased demand for gas in the growing electric utility sector would reduce market uncertainty and encourage investment in exploration and development of domestic gas resources.
- Gas-fired, combined-cycle power plants provide an option for utilities to add efficient small increments of capacity with short lead times (3 years from the date of order as compared to 6 to 10 years for coal plants). This option would reduce the danger of capacity shortfalls arising from greater than anticipated load growth.
- Most projections of U.S. energy outlook include a heavy reliance on coal, involving a 40 to 50 percent increase over current consumption by the year 2000. Greater use of gas in electric utilities would mitigate somewhat the environmental and logistical problems associated with increased coal use.
- To comply with the exemption process of the Fuel Use Act takes between 3 and 14 months to complete and costs anywhere from $10,000 to $100,000.

Disadvantages

- Because of unequal regional endowments of old price controlled gas, consumers in some areas could pay more for their gas, in the short run, if all gas prices were decontrolled.
- Decontrol may lead to congressional initiatives to impose excise taxes on old gas, which would be counterproductive.
- Old gas decontrol would affect many contracts, business relationships, and financial obligations, many of which are of long standing. A sudden switch from a controlled to a decontrolled market could cause severe transition problems for certain companies and individuals. Among the issues affected by decontrol of old gas are:

  1) Contract provisions
  2) Transportation problems
  3) Relationships between federal and state governments
  4) Anti-trust issues
  5) Relative competitive advantages and disadvantages of individual producers, pipelines, or distributors.

- The standby fuels for gas-fired, combined-cycle electric generating plants are likely to be petroleum products (probably distillates), which could increase the potential national use of oil in the event of seasonal gas supply constraints or a supply shortfall.
- Removal of restrictions on natural gas as a primary fuel is likely to encourage utilities to adopt the gas option for some portion of new electric generating capacity, thereby reducing the use of a known domestic abundant resource—coal—and not reserving gas and domestic oil to displace imported petroleum in more specialized uses.
- Reduced use of coal would lower the rate of growth of domestic employment in the coal mining and railroad service industries.

OPTIONS TO REDUCE DEPENDENCE ON IMPORTED OIL—REDUCE OIL AND GAS DEMAND

Another way to reduce U.S. dependence on oil imports is to reduce demand. Options to reduce demand are presented in this section.

The oil price shocks of the 1970s demonstrated that oil demand is responsive to changes in prices. After peaking in 1978 at 18.9 MMB/D, U.S. oil demand declined following the second price shock to 15.7 MMB/D in 1985. The policy options presented are to:

1. Reduce demand by increasing the price of oil through consumption and excise taxes
2. Create incentives and mandates to continue energy conservation efforts
3. Encourage greater use of alternative fuels as substitutes for oil and gas.

Enact Energy Consumption and Excise Taxes

A tax on energy consumption would raise the price of energy and stimulate conservation. Such a tax would also raise general revenue or finance incentives for exploration, development, and production of domestic energy reserves.

Among options to be considered are a consumption tax or a BTU tax on all energy supplies, an excise tax on all oil supplies or refined petroleum products, and an increase in the motor fuels excise tax.

A broad-based energy consumption tax could be applied to most domestic and imported energy supplies, including oil, natural gas, coal, and nuclear power. Renewable resources, such as wood, solar, and hydroelectric power, could be exempted. The tax could be assessed as a percentage of the cost of energy or at a flat rate per BTU. The tax could be collected at the point of production or importation, or at the wholesale level.

A per barrel tax could be imposed on all crude oil (foreign and domestic) used by refineries, with a similar tax applicable to imported petroleum products. The crude oil tax could be collected at the refinery gate. The tax on imported products could be collected at the time of importation when U.S. Customs tariffs are collected. The Congressional Budget Office has estimated that a $5 per barrel oil excise tax would generate $22 to $25 billion per year in federal revenue.

A variation of the preceding oil excise tax would be an excise tax similar to the motor fuels tax levied on all refined petroleum products. The effects would be similar to the oil excise tax, but collection procedures would resemble those for the motor fuels tax.

The federal excise tax on motor fuels (gasoline and diesel) could be raised. The additional annual revenue is projected to be more than $1 billion for every 1 cent per gallon increase. However, unless current laws were changed, the additional revenue would flow into the Highway Trust Fund.

Advantages

- Consumption taxes on energy or oil would reduce demand.
- Consumption taxes would raise revenue that could be used to maintain existing production and stimulate new oil and gas exploration and development activity.
- Consumption taxes without exploration and production incentives would reduce oil imports, but not as much as an import fee since domestic production is not stimulated. Taxes on oil consumption would reduce imports more than broad energy taxes.
- An oil excise tax would encourage domestic natural gas and coal production, since their prices could rise with the tax inclusive price of oil.

Disadvantages

- Consumption taxes without exploration and production incentives would not stimulate domestic exploration and development of energy because the prices to producers would be unaffected.
- U.S. economic growth would be slowed and inflation would be increased.
- Consumption and excise taxes, like an oil import fee, are considered to be regressive. For example, households with incomes below $7,400 per year spend about 8 percent of their income on gasoline, while those with incomes above $36,000 typically spend about 4 percent.
- Most energy consumption taxes would impair the ability of U.S. manufacturers to compete with foreign companies in the United States and abroad. An increase in motor fuels excise tax would have the least effect on the costs of U.S. goods, except for goods for which transportation in the United States accounts for a large share of the final cost.
- Most energy consumption taxes would be difficult to administer and collect. The tax must be determined for each form of energy so that it does not upset the competitive position of that energy form relative to others. An inappropriate tax differential between crude oil and products could increase petroleum product imports or encourage refinery inefficiencies. A tax on motor fuels would be easiest to administer, because collection and accounting systems are already in place.
- To various degrees, energy consumption taxes would result in economic distortions. These distortions would be smaller for broad-based energy taxes, which would raise a given amount of revenue with the lowest tax rate.

Create Incentives and Mandates for Conservation

Peacetime energy conservation was never an issue of national importance until the 1973

Arab oil crisis exposed the nation's vulnerability to disruptions of its major energy source. The crisis triggered a wide-ranging response by public officials aimed at reducing energy consumption, especially oil. Many of the incentives and mandates are still in place, but it is generally accepted that price has been the principal driving force for conservation to date. Oak Ridge National Laboratory has attributed 70 percent of U.S. energy savings in the early 1980s to price response.[1] The decline in oil prices that began in 1982 has led to a reduced commitment to conservation, and mandated standards are now being ignored or moderated.

A renewed commitment to such standards and incentives is one of the options to reduce the nation's vulnerability to future energy crises.

Recent studies indicate that the 55 mile per hour speed limit saved about 150,000 barrels per day of gasoline until at least 1983. However, the current law is frequently violated and difficult to enforce because of diminishing public support.

Maintaining the 27.5 miles per gallon (MPG) Corporate Average Fuel Economy (CAFE) standard for new automobiles would reduce gasoline consumption about 250 MB/D in the year 2000, compared to the volume consumed if the temporary 26.0 MPG standard were extended to 2000 (if both standards were binding). Some automobile manufacturers claim, however, that maintaining the 27.5 MPG standard could cost U.S. industry thousands of jobs due to the shutdown of large-car plants, and that new automobile efficiencies will continue to improve even after the mandated efficiencies have been achieved.

Encourage Greater Use of Alternative Fuels to Oil and Gas

While the United States possesses proved reserves of only 28 billion barrels of oil and 193 TCF of natural gas—4 percent and 5 percent, respectively, of world totals—the U.S. possesses 283 billion short tons of coal, 29 percent of the world's total recoverable coal reserves. These coal reserves are roughly equal to 80 times the total energy consumed in the United States in 1985.

In 1985, coal provided 23 percent of U.S. total energy consumption, primarily in the generation of electricity. In 1985, 56 percent of U.S. electricity was generated from coal, up from 46 percent in 1970. The NPC Oil & Gas Outlook Survey shows coal usage increasing by 45 percent between 1985 and 2000.

Nuclear energy has shown the most dramatic growth over the past 25 years, increasing from zero in 1960 to almost 16 percent of all U.S. electricity generated in 1985. The NPC survey shows nuclear growing by almost 50 percent from 1985 to 2000.

The NPC survey shows the contributions of coal and nuclear to U.S. energy requirements to be the same for both price trends. This is due primarily to the long lead times required to construct new generating stations. Most of the new power plants that will be operating in 2000 have already been announced and included in the survey responses. However, should electricity requirements grow faster than shown in the survey, the only ways to meet the increased requirements would be by construction of combined cycle plants burning natural gas and distillate and by increased consumption of residual fuel oil in older oil-fired plants. This would increase U.S. oil imports.

To avoid this eventuality, options to encourage the use of coal and nuclear could be developed. Such options include amending the Clean Air Act to allow the use of low sulfur coal without stack-gas scrubbing when emissions are already in compliance, developing environmentally acceptable licensing and permitting procedures to reduce the costs and construction time of coal-fired and nuclear power plants, and reducing the transportation costs of coal.

OPTIONS TO REDUCE THE LIKELIHOOD OF ENERGY CRISES AND/OR MITIGATE THEIR IMPACT

These policy options are to:

1. Diversify oil supply sources to reduce the likelihood that a disruption of a single source could precipitate a crisis
2. Pursue diplomatic policies that promote greater stability in the Middle East and Africa and greater interdependence with the United States
3. Expand and use strategic petroleum reserves to enhance the ability to limit the effects of supply shortages and price increases; the presence of such reserves reduces the likelihood of disruptions being used as a political tool
4. Develop fiscal and monetary policies that could be used to mitigate the impacts of oil price shocks, and could act to reduce the likelihood of oil supply disruptions.

[1] Sawhill, John C., and Cotton, Richard, eds., "Energy Conservation Successes and Failures." 1986.

Diversify Oil Supply Sources

There have been six major oil supply disruptions since World War II, not all of which precipitated a world oil supply crisis. All of these disruptions were caused by events in the Middle East: the Iranian nationalization of the British Petroleum concessions in 1951, the Suez crisis in 1956–57, the June War in 1967, the Arab oil embargo in 1973, the Iranian revolution in 1978, and the Iran/Iraq war beginning in 1980. The disruptions had a minimal impact when surplus productive capacity existed outside of OPEC. A useful goal is the diversification of oil supply sources for the world as a whole. This would diminish the impact of a disruption in any single source of supply, and would decrease the ability of some oil exporters of using oil as a political weapon.

Because oil is an international commodity, the United States cannot isolate itself from the impact of a world oil supply disruption or price increase by diversifying its import sources. Even though imports of oil from the Western Hemisphere and from Western Europe are probably more secure than supplies from most other areas, crude oil is traded in an integrated worldwide market. Because of this integration and U.S. participation in International Energy Agency sharing agreements, a major physical disruption anywhere in the non-communist world would be felt, even if the specific imports of the United States were not disrupted. Furthermore, a rise in the world price of crude oil will be reflected in the United States regardless of the source of imports.

Pursue Diplomatic Policies

The Middle East has almost two-thirds of the non-communist world's proved oil reserves (Table 51 in Chapter Eight) and is the world's lowest cost oil producer. U.S. dependence on oil as an energy source will continue in the long term, and the United States will rely on the Middle East for oil to a significant extent. Middle East oil supplies are critical to the non-communist world.

One option to reduce the likelihood of an oil crisis is to pursue diplomatic policies that promote greater stability in the Middle East and Africa and greater interdependence with the United States. Substantial economic interdependence can reduce the likelihood of price shocks and the attractiveness of using oil as a political weapon. Energy policy is a part of overall U.S. economic, diplomatic, and defense objectives in the world. There is a tradeoff between such objectives and the need to protect the domestic economy from an oil crisis that may be triggered by events in the Middle East.

Expand and Use Strategic Petroleum Reserves

In response to the Arab oil embargo in 1973–74, the U.S. Congress authorized the creation of the SPR, to be used in times of oil disruptions to mitigate the effects of physical shortages and restrain the oil price increases associated with such supply/demand imbalances. The SPR currently contains more than 510 million barrels of oil. With declining exploration activity and oil production and increasing oil imports, an option to consider is increasing the size and delivery capacity of the SPR, at least to the current goal of 750 million barrels and possibly beyond as oil import dependence grows. U.S. allies, trade partners, and other consuming nations might also be encouraged to establish and maintain strategic petroleum stockpiles of their own.

One study analyzed the ability of an SPR drawdown to mitigate the impact of an oil supply disruption involving a reduction in OPEC production of 7 MMB/D for one year. The results showed that, in the case of a unilateral drawdown by the United States, use of the SPR would offset about one-third of the loss in GNP traceable to the shock.[2]

Advantages

- The maintenance of strategic petroleum reserves provides consuming nations with the ability to offset limited, temporary supply curtailments resulting from embargoes and other oil supply disruptions.
- The timely release of oil from the reserves could also assist in holding down prices and reducing panic buying.
- The very existence of a sizeable strategic reserve reduces the likelihood that oil-exporting nations would utilize oil embargoes and production cuts as political or economic weapons.
- Increasing the size of the Strategic Petroleum Reserve acts to maintain a given level of responsiveness to an oil disruption as oil import volumes are increasing.
- With oil prices down, the costs of expanding the reserves have been reduced.
- Purchasing greater quantities when prices are low is not only fiscally sensible, but also helps stabilize prices by increasing overall demand.

[2]See the review by Hubbard, Glenn, and Weiner, Robert, "Managing the Strategic Petroleum Reserve: Energy Policy in a Market Setting." *Annual Review of Energy* 10 (1985): pp. 515-556.

Disadvantages

- The principal drawback to the creation and maintenance of a strategic reserve is the cost involved in creating storage facilities, purchasing the oil to be placed in storage, and maintaining the facilities.
- Without the cooperation of other consuming nations to develop their own adequate strategic reserves, the United States could be required through treaty agreements to utilize its SPR to mitigate supply disruptions directed at other countries. Lack of international stockpile coordination would reduce the effectiveness of an SPR release in mitigating the economic costs of an oil supply disruption.
- In the event of an extended supply disruption, the reserves could be exhausted while only delaying the inevitable oil price increase.

Develop and Use Monetary and Fiscal Policies

In the event of an oil price shock, monetary and fiscal policies could be used to lessen the economic costs the shock would inflict.[3] Such policies could prevent a large drop in aggregate demand by stimulating consumption and investment, or they could ease the adverse impacts on production costs and productivity by reducing labor costs and increasing the capital stock. The goal of these policy responses is to reduce the income and unemployment costs of an oil supply disruption/price shock without inflicting an unacceptable stimulus to inflation. Having such policies on the shelf and known to the oil-exporting countries upon which the United States depends for oil imports would reduce the effectiveness and likelihood of oil supply disruptions being used as a political weapon. Several potential short-run macroeconomic policies and their underlying goals are shown in Table 54.

[3]In a 1983 study, the Stanford University Energy Modeling Forum 7 (EMF7) considered several policies for reducing the economic costs of an oil price shock. For a detailed discussion of the EMF7 study and the principal conclusions, see Hickman, Bert and Huntington, Hillard, "Macroeconomic Impacts of Energy Shocks: An Overview." EMF Working Paper 7.2, Stanford University, 1984.

TABLE 54

SHORT-RUN MACRO POLICY RESPONSES TO OIL SUPPLY SHOCKS

Fiscal Responses	Monetary Responses	Intended Impacts
(1) Temporary reduction in personal income taxes	—	(1) Stimulate consumer spending
(2) Temporary reenactment of the investment tax credit	—	(2) Stimulate business investment, thereby improving productivity and speeding adjustment to higher oil prices
(3) Temporary decrease in payroll taxes	—	(3) Mitigate any decline in the demand for labor; reduce inflationary pressure
—	(4) One-shot increase in the level of money supply	(4) Mitigate rise in interest rate and drop in aggregate demand without permanently increasing rate of inflation
—	(5) Permanent increase in the growth of the money supply	(5) Mitigate rise in interest rate and drop in aggregate demand
—	(6) Temporary decrease in monetary growth	(6) Avoid increase in the price level

Appendices

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

September 23, 1985

Dear Mr. Bailey:

Since the 1970's energy crises, there have been numerous technical developments in the production and consumption of energy as well as new analytical tools and models developed for looking to the future. Our energy efficiency has increased; domestic energy resources are being developed more effectively; real prices have declined; U.S. dependence on foreign energy sources has diminished; and the Nation's vulnerability to energy supply disruptions has been reduced. However, we must not become complacent because the factors that determine future energy supply and demand are constantly changing.

Accordingly, I am requesting the National Petroleum Council to undertake a new study examining the factors affecting the Nation's future supply and demand of oil and gas. The study should also examine the set of factors that precipitated the 1970's energy crises, their financial impact on the Nation's economy, the appropriateness of government's response, and the potential for a recurrence. This retrospective analysis should provide advice on how the vulnerability to future crises can be avoided or mitigated.

For the purpose of this study, I designate Donald L. Bauer, Acting Assisting Secretary for Fossil Energy, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Yours truly,

John S. Herrington

John S. Herrington

Mr. Ralph E. Bailey
Chairman
National Petroleum Council
1625 K Street, NW
Washington, DC 20006

Description of the National Petroleum Council

In May 1946, the President stated that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that this close relationship should be continued and suggested that the Secretary of the Interior establish an industry organization to provide advice on oil and natural gas matters. Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The sole purpose of the NPC is to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. Matters that the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of Energy include:

- *Materials and Manpower Requirements* (1979)
- *Petroleum Storage & Transportation Capacities* (1979)
- *Refinery Flexibility* (1979, 1980)
- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil and Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Petroleum Inventories and Storage Capacity* (1984)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

National Petroleum Council Membership 1987

ALLEN, Jack M.
President
Alpar Resources, Inc.

AMES, Eugene L., Jr.
President
Venus Oil Company

ANDERSON, Glenn P.
President
Andover Resources Corporation

ANGELO, Ernest, Jr.
Petroleum Engineer
Midland, Texas

BADEN, John A.
Executive Director
Maguire Oil and Gas Institute
Southern Methodist University

BAILEY, Ralph E.
Chairman and Chief Executive Officer
Conoco Inc.

BARNES, James E.
President and Chief Executive Officer
MAPCO Inc.

BARTON, W. A.
Chairman Emeritus
Barton Valve Company, Inc.

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Appendix C

Economic Modeling

Modeling and Analytic Approaches

In addition to the lack of historical experience with an oil shock, there were a number of technical reasons for the slowness in recognizing the impacts of the 1973 oil embargo and the ensuing rise in oil prices. For example, the modern theory of aggregate supply had only begun to reach the technical journals in the late 1960s, with the work of Milton Friedman[1] and Edmund Phelps,[2] among others, and the oil shock had aggregate supply as well as aggregate demand impacts.

Even the aggregate demand impacts of the first oil shock were surprisingly slow to be recognized: surprisingly because fiscal policy had been the demand-management success story of the previous decade. The first reference in *The Wall Street Journal* to the impact of higher fuel prices on consumer disposable incomes was an article in early January of 1974, nearly three months after the imposition of the Arab oil embargo. Not surprisingly, the author of that piece was Walter Heller, who had been one of the principal architects of the successful Kennedy-Johnson tax cut of the early 1960s. The February 1974 *Report of the Council of Economic Advisors* did not place much emphasis on aggregate demand impacts.

In the absence of historical experience, macroeconomic impact estimates seemed to be made on the backs of envelopes. Inflation impacts were typically estimated from energy weights in the various price indexes (apparently without correcting for stage of processing: fuel becomes an input cost in fuel-using industries).

Real output impacts were estimated by backing out some amount of oil consumption and trying to tie shortages to levels of industrial activity, perhaps with some scope for interfuel substitution or conservation. One shortcoming of this approach was the extreme year-to-year variability in the observed relationship between growth in energy consumption and growth in real output. Furthermore, one could never tell how much of a reduction in oil demand in a recession year (such as 1974) was due to "shortage" and how much to other factors.

In any event, most forecasts of macroeconomic impacts based on "shortages" missed the mark. The recession deepened during 1974—in part due to Fed tightening of the money supply (though that action affected primarily the latter part of 1974)—rather than easing, as many commentators expected and as would have been implied by the lifting of the embargo and freer availability of product. What happened was that the resource cost of obtaining imported oil increased during the embargo but did not fall when supplies became more abundant. In short, the quantity approach failed to reflect the issue of acquisition cost in the 1974 period.

Retrospective Studies

Several retrospective studies of the impact of the first oil shock have been made. One can classify them in terms of five somewhat overlapping approaches:

1) Indirect production function: reduced energy input

[1] For example, Friedman, Milton, "The Role of Monetary Policy." *American Economic Review*, vol. 58 (March 1968), pp. 1–17.

[2] For example, Phelps, Edmund S., "Money Wage Dynamics and Labor Market Equilibrium." *Journal of Political Economy*, vol. 76 (July/August 1968), pp. 687–711.

2) Production function: capital obsolescence/potential GNP

3) Extensive growth decomposition (production function)

4) Conventional econometric model simulation

5) Econometric-process model simulation

The first three approaches relate economic output to factor inputs. Capital, labor, and natural resources are the three classic factors of production; empirical macroeconometric analyses often ignore the resource inputs. In practice, one does not necessarily estimate a production function directly in terms of factor inputs; measurement issues (how much capital is used, for example) and technical statistical issues often dictate the approach taken.

Under the assumption of competitive marketplaces, one can relate uniquely estimates of demand equations for each factor to the underlying production function. Specifically, demand for each factor depends upon relative factor prices and total output. By this indirect method, one can avoid some rather messy measurement problems.

The first approach cited above takes full use of the indirect approach by making energy a factor of production. Then, in principal, one can solve for the underlying production function and ask the question, "What would have happened if energy prices did not increase in 1974?" Moreover, one can ask the question without trying to guess how great the "shortage" was (if any).

Unfortunately, despite its theoretical appeal and its occasional use in the literature, the approach fails. Specifically, the indirect approach assumes that the underlying markets are competitive. In the case of energy during the early 1970s (and, arguably, before), the marketplace was anything but competitive. All energy commodities and products were subject to the price controls of the Nixon administration. Moreover, other energy prices—natural gas and electricity, for example—were subject to price controls for longer periods; even crude oil prices were effectively regulated (before OPEC's 1973 embargo) through domestic production limitations such as prorationing by the Texas Railroad Commission and limitations on imports.

In a world of price controls, the fundamental law of demand need not apply. Specifically, it may be true that raising price will lead to raising consumption. If this situation occurred (as it may have in the early 1980s with natural gas price regulation under NGPA), then, obviously, OPEC's actions to raise U.S. energy prices would have led to an increase in U.S. real economic output. Such an implication would hardly be credible.

The second approach—estimating the effect on the capital stock and, thus, potential output—is more fruitful. Essentially, the notion is that rising energy prices in the 1970s rendered some fraction of the capital stock uneconomic to operate. With a smaller capital stock, the economy's potential output is lower. Rasche and Tatom[3] estimate that potential output fell for this reason by perhaps 5 percent between the last quarter of 1973 and the third quarter of 1974.

The 5 percent figure seems high, given that the peak to trough decline in GNP was slightly less—4.3 percent—and the U.S. economy was at full employment in the fourth quarter of 1973, and that the inflation rate fell markedly by 1976. If capacity fell more than output (though, to be sure, industrial production fell by nearly 15 percent) from a position of full employment, inflation should not have declined much and could well have increased.

Studies using the third approach—the detailed decomposition of growth rates into sources—tend to agree with the above criticism. Denison,[4] for example, finds only limited importance to the aggregate supply effects of reduced energy consumption in the post-1973 period, though there was a greater impact post-1979. His analysis is in terms of explained and residual productivity growth and includes the following considerations: the timing of the slowdown in residual productivity growth after 1973, the fact that energy conservation was underway well before the OPEC embargo, the failure of published business opinion to reflect any impact of energy on productivity, and the small share of energy in output in 1973 (albeit larger by 1979, when greater conservation was observed as well).

Econometric models (the fourth approach) and econometric/process models (the fifth approach) represent the most complete and complex set of estimates. Different models produce different results, not only because of their properties but also because of the way the simulations are controlled.

[3]Rasche, Robert H., and Tatom, J. A., "The Effects of the New Energy Regime on Economic Capacity, Production, and Prices." Federal Reserve Bank of St. Louis *Review* (May 1977), pp. 2–12, and "Energy Resources and Potential GNP." Federal Reserve Bank of St. Louis *Review* (June 1977), pp. 10–24.

[4]Denison, Edward F., *Trends in American Economic Growth, 1929–1982*. Washington, DC: The Brookings Institution, 1985, pp. 52 ff.

Two key—and somewhat related—modeling issues concern the specification of energy sector inputs and the treatment of macroeconomic policy. Both items are important in any single simulation and in comparing simulations with different models.

The first issue arises because models are constructed with different elements and because items excluded from a model might be the most important sources of impact. For example, it was not uncommon, prior to 1973, for econometric models not to incorporate energy prices explicitly. Now models typically include some detail for the energy sector. In any event, the modeling issue is to find adequate representations for items outside of the model.

The policy issue can be more serious. Fiscal and monetary policies obviously affect the performance of the economy, hence one would like to keep them "unchanged" to separate out the impacts of changing oil prices. However, the notion of "unchanged" policy is far from unambiguous, even apart from sharp differences of opinion in how policies actually work.

For example, holding fiscal policy constant can mean that federal purchases are unchanged in either nominal or real terms. Holding state and local government expenditures constant involves the same choice. Holding transfer payments constant can mean either holding programs unchanged or amounts of money transferred unchanged. On the tax side, tax rates or tax revenues can be held constant, in nominal or real terms.

Monetary policy can be held constant by setting any of several monetary aggregates, in nominal or real terms. Alternatively, an instrument—e.g., nonborrowed reserves or an interest rate—may be held constant. All of these variables may be controlled in a simulation, and the issue is what assumptions are made, explicitly or implicitly.

A recent trend in econometric models recognizes that economic policy is not made in a vacuum. More and more models have reaction functions for monetary policy, in which the Fed's actions depend on what happens in the economy. As a modeling issue, is monetary policy being held "constant" if a reaction function is left in place? Analytically, keeping policy at least partially endogenous will act to mitigate the impacts of external shocks, such as oil price changes. Moreover, it is arguable that keeping the rules under which the Fed operates unchanged (i.e., the reaction function) is a form of holding monetary policy constant, albeit a somewhat complicated one.

In any event, holding policy "constant" is hardly a trivial exercise.

Holding economic policy constant, moreover, is not the only control issue in working with macroeconometric models. Many behavioral relationships are omitted from models for perfectly valid reasons. However, one may not wish to ignore these relationships in the case of such sharp discontinuities such as oil price shocks.

TABLE C-1

IMPACT OF 1973 OIL PRICE SHOCK
(DRI Model Results)

	1973	1974	1975	1976
Percent Difference in Levels				
Real GNP	-0.5	-3.3	-5.3	-4.5
Real Consumption	-0.4	-3.0	-5.6	-5.7
Real Nonresidential Investment	-0.5	-5.5	-11.5	-9.4
Industrial Production	-0.7	-5.2	-9.1	-7.4
Housing Starts	-3.0	-18.9	-23.3	-10.9
Unit Car Sales	-3.3	-23.3	-29.9	-23.2
Unemployed Persons	1.7	14.1	19.6	18.2
Difference in Inflation Rates				
GNP Deflator	0.1	1.5	1.6	-0.1
Consumer Price Index	0.7	4.0	1.6	0.3

Source: Eckstein, Otto, *The DRI Model of the U.S. Economy*. New York: McGraw-Hill Book Company, 1983, p. 244.

TABLE C-2

ECONOMIC IMPACT OF 1973 OIL PRICE SHOCK
(Actual versus Hypothetical No-Shock Case, Wharton Mark 8 Model)

	1973	1974				1975				1976		
	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3
Real GNP												
(Billion 1982 $)	0.17	-2.53	-7.94	-11.09	-26.16	-37.83	-48.85	-58.87	-66.77	-73.06	-77.68	-79.70
% Difference	0.01	-0.09	-0.29	-0.41	-0.96	-1.41	-1.79	-2.10	-2.35	-2.52	-2.66	-2.72
GNP Deflator												
(1982 = 100)	-0.10	-0.16	0.05	0.53	0.74	0.98	1.15	1.17	1.17	1.28	1.45	1.65
% Difference	-0.20	-0.31	0.09	0.98	1.34	1.74	2.03	2.02	1.98	2.15	2.41	2.70
Consumer Price Index												
(1967 = 100)	0.57	2.11	3.19	3.71	4.59	4.88	5.08	5.20	5.48	6.04	6.56	6.72
% Difference	0.42	1.51	2.25	2.55	3.08	3.22	3.32	3.34	3.46	3.77	4.08	4.11
Unemployment Rate (% Points)	0.00	0.02	0.08	0.16	0.32	0.53	0.78	0.98	1.15	1.28	1.37	1.41
Interest Rates (% Points)												
3-Month T-Bills	0.00	0.25	0.93	1.34	1.30	1.18	0.84	0.49	0.24	0.17	0.22	0.24
AAA Bonds	0.00	0.09	0.33	0.58	0.75	0.85	0.77	0.55	0.36	0.28	0.36	0.51
Consumption												
(Billion 1982 $)	-1.95	-7.85	-13.40	-17.59	-25.33	-32.32	-38.87	-44.33	-49.33	-54.07	-58.16	-61.18
% Difference	-0.12	-0.47	-0.79	-1.03	-1.50	-1.89	-2.22	-2.51	-2.75	-2.94	-3.14	-3.26
Nonresidential Fixed Investment												
(Billion 1982 $)	0.27	0.95	1.20	0.59	-1.25	-3.97	-6.85	-10.03	-13.04	-15.51	-17.63	-19.35
% Difference	0.08	0.29	0.37	0.19	-0.41	-1.37	-2.40	-3.44	-4.35	-5.08	-5.67	-6.07
Industrial Production												
(1977 = 100)	0.32	1.21	1.51	0.36	-0.92	-1.62	-2.48	-3.09	-3.27	-3.10	-2.93	-3.17
% Difference	0.33	1.32	1.65	0.38	-1.01	-1.93	-2.96	-3.53	-3.61	-3.32	-3.08	-3.28
Car Sales (Millions)	-0.20	-0.76	-1.10	-1.19	-1.38	-1.57	-1.55	-1.42	-1.41	-1.37	-1.35	-1.30
% Difference	-2.02	-7.63	-11.11	-10.08	-16.01	-16.00	-16.36	-13.61	-13.08	-12.00	-12.03	-11.64
Housing Starts (Millions)	-0.01	-0.02	-0.05	-0.07	-0.10	-0.14	-0.18	-0.21	-0.20	-0.21	-0.21	-0.20
% Difference	-0.35	-1.57	-3.19	-5.63	-9.06	-11.95	-14.11	-13.73	-12.78	-12.26	-12.24	-11.39
Trade Balance												
(Billion $)	-0.71	-1.35	-9.86	-8.90	-9.40	-7.62	-6.00	-7.77	-8.99	-8.38	-8.45	-8.67
Federal Budget Deficit												
(Billion $)	-0.28	0.10	0.25	-0.78	-2.75	-4.72	-6.55	-9.88	-12.27	-12.43	-12.35	-12.78
Oil Consumption												
(MMB/D)	-0.02	-0.10	-0.16	-0.25	-0.42	-0.55	-0.61	-0.71	-0.85	-0.97	-0.95	-1.02
% Difference	-0.15	-0.58	-1.00	-1.51	-2.34	-3.09	-3.74	-4.28	-4.83	-5.14	-5.45	-5.78
Oil Imports												
(Billion 1982 $)	-0.18	-0.68	-1.73	-2.51	-5.92	-5.52	-6.87	-8.18	-9.32	-10.31	-11.23	-12.08
% Difference	-0.20	-1.08	-2.12	-3.09	-4.54	-6.90	-9.02	-9.58	-10.39	-11.22	-11.29	-11.47

TABLE C-3

ECONOMIC IMPACT OF 1979 OIL PRICE SHOCK
(Actual versus Hypothetical No-Shock Case, Wharton Mark 8 Model)

	1979				1980				1981			
	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3	Q-4
Real GNP												
(Billion 1982 $)	-2.98	-10.38	-17.00	-27.37	-43.42	-60.40	-79.07	-93.28	-103.79	-112.50	-118.42	-118.16
% Difference	-0.09	-0.33	-0.53	-0.85	-1.32	-1.88	-2.44	-2.84	-3.10	-3.35	-3.52	-3.57
GNP Deflator												
(1982 = 100)	-0.05	-0.03	0.35	0.76	1.24	2.22	2.81	3.26	3.72	3.97	4.10	4.50
% Difference	-0.07	-0.04	0.44	0.94	1.51	2.68	3.35	3.80	4.23	4.46	4.50	4.87
Consumer Price Index												
(1967 = 100)	0.62	2.27	3.78	5.54	7.63	8.91	10.82	12.09	12.27	12.45	12.91	13.22
% Difference	0.30	1.07	1.74	2.49	3.33	3.77	4.53	4.94	4.88	4.84	4.89	4.93
Unemployment Rate (% Points)	0.02	0.08	0.19	0.33	0.53	0.78	1.07	1.34	1.57	1.72	1.83	1.86
Interest Rates (% Points)												
3-Month T-Bills	0.00	0.14	0.53	0.84	1.10	1.41	1.38	1.11	0.83	0.54	0.25	0.04
AAA Bonds	0.00	0.05	0.21	0.42	0.68	0.86	0.92	0.92	0.80	0.67	0.59	0.53
Consumption												
(Billion 1982 $)	-1.94	-7.33	-13.22	-21.29	-32.53	-41.85	-52.88	-62.55	-69.68	-73.84	-77.89	-79.51
% Difference	-0.10	-0.37	-0.66	-1.04	-1.58	-2.08	-2.58	-3.02	-3.33	-3.53	-3.71	-3.80
Nonresidential Fixed Investment												
(Billion 1982 $)	-0.07	-0.43	-1.28	-2.87	-5.41	-8.76	-12.48	-16.72	-21.20	-24.67	-26.98	-27.74
% Difference	-0.02	-0.11	-0.33	-0.72	-1.34	-2.30	-3.28	-4.29	-5.26	-5.94	-6.36	-6.62
Industrial Production												
(1977 = 100)	0.26	1.05	1.48	1.00	0.32	-0.89	-2.71	-4.26	-5.75	-6.76	-6.64	-5.97
% Difference	0.24	0.95	1.34	0.91	0.29	-0.83	-2.51	-3.76	-4.96	-5.77	-5.64	-5.29
Car Sales (Millions)	-0.15	-0.60	-0.99	-1.44	-2.20	-2.54	-2.75	-2.80	-2.64	-2.41	-2.20	-2.03
% Difference	-1.34	-5.42	-8.45	-12.68	-17.48	-24.94	-24.10	-24.03	-21.47	-23.27	-19.97	-22.28
Housing Starts (Millions)	-0.01	-0.02	-0.05	-0.08	-0.12	-0.15	-0.20	-0.21	-0.23	-0.22	-0.21	-0.19
% Difference	-0.40	-1.31	-2.60	-4.98	-9.12	-12.54	-12.93	-12.34	-14.36	-16.36	-18.21	-18.33
Trade Balance												
(Billion $)	-0.73	-3.60	-6.39	-10.62	-11.39	-10.48	-3.44	-6.50	-5.04	-5.17	-3.27	-1.27
Federal Budget Deficit												
(Billion $)	-0.44	-0.93	-1.28	-3.00	-4.98	-5.00	-9.36	-13.70	-18.58	-22.43	-25.18	-23.67
Oil Consumption												
(MMB/D)	-0.02	-0.07	-0.14	-0.27	-0.45	-0.57	-0.79	-1.08	-1.33	-1.44	-1.66	-1.91
% Difference	-0.10	-0.39	-0.78	-1.43	-2.37	-3.35	-4.68	-5.87	-7.24	-8.43	-9.64	-10.68
Oil Imports												
(Billion 1982 $)	-0.09	-0.53	-1.25	-2.36	-4.04	-6.05	-8.42	-11.11	-14.00	-16.67	-19.16	-21.61
% Difference	-0.09	-0.50	-1.23	-2.23	-4.05	-6.57	-10.51	-12.52	-15.84	-18.31	-20.95	-24.12

TABLE C-4

POST-1973 INDUSTRIAL PRODUCTION INDEXES, OIL AND GAS INDUSTRIES
(Percentage Changes from November 1973)

Industry	After One Year	After Two Years	After Three Years
Crude Oil and Natural Gas Extraction	-2.8	-4.5	-4.4
Production, Crude Oil and Natural Gas	-6.2	-10.4	-11.7
Crude Oil (Total)	-5.9	-9.4	-12.0
Alaska and California	-2.8	-3.6	-0.3
Texas	-4.0	-6.6	-9.9
Louisiana and Other	-8.4	-13.4	-16.6
Natural Gas	-6.7	-12.9	-11.5
Drilling and Services	16.4	29.9	37.4

POST-1979 INDUSTRIAL PRODUCTION INDEXES, OIL AND GAS INDUSTRIES
(Percentage Changes from February 1979)

Industry	After One Year	After Two Years	After Three Years
Crude Oil and Natural Gas Extraction	7.2	10.1	16.1
Production, Crude Oil and Natural Gas	2.7	-0.3	0.6
Crude Oil (Total)	1.6	0.3	1.3
Alaska and California	15.8	17.2	24.8
Texas	-5.1	-8.1	-10.6
Louisiana and Other	-1.2	-3.0	-3.3
Natural Gas	8.1	2.2	3.2
Drilling and Services	30.5	67.8	103.8

TABLE C-5

SHORT-TERM IMPACTS OF NPC PRICE SCENARIOS

	1985	1986				1987				1988				1989
	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1	Q-2	Q-3	Q-4	Q-1
Wharton PC Mark 8														
Real GNP (Billion 1982 $)														
Lower Price Trend	3,590.80	3,700.30	3,683.80	3,716.90	3,762.40	3,800.60	3,828.60	3,855.20	3,876.20	3,889.20	3,913.20	3,940.60	3,968.70	3,987.70
Upper Price Trend	3,590.80	3,654.00	3,644.90	3,674.80	3,715.70	3,746.70	3,770.50	3,796.50	3,819.00	3,834.20	3,863.90	3,897.70	3,929.50	3,948.00
Inflation Rate (Annualized Rate of Change in Consumer Price Index)														
Lower Price Trend	N/A	-4.57	-2.89	1.81	3.30	4.39	4.40	4.30	4.15	5.05	4.62	4.54	4.46	5.22
Upper Price Trend	N/A	-0.75	-0.73	2.76	3.76	4.98	4.87	4.53	4.37	5.40	4.87	4.63	4.64	5.58
Car Sales (Millions)														
Lower Price Trend	10.30	11.70	11.50	11.00	10.80	10.50	10.10	10.10	10.00	9.90	9.90	9.90	9.90	9.80
Upper Price Trend	10.30	11.00	10.70	10.50	10.50	10.30	10.00	10.10	10.20	10.20	10.20	10.30	10.40	10.30
Unemployment (Percentage)														
Lower Price Trend	7.00	6.50	6.40	6.30	6.20	6.10	6.00	6.00	6.10	6.30	6.40	6.60	6.70	6.90
Upper Price Trend	7.00	6.70	6.80	6.80	6.70	6.70	6.60	6.60	6.70	6.80	7.00	7.00	7.10	7.20
Washington University Model														
Real GNP (Billion 1982 $)														
Lower Price Trend	3,590.80	3,623.50	3,644.50	3,681.70	3,712.60	3,742.80	3,767.60	3,792.70	3,815.50	3,841.10	3,869.30	3,897.10	3,926.60	—
Upper Price Trend	3,590.80	3,623.50	3,639.90	3,671.10	3,697.70	3,724.00	3,744.80	3,766.60	3,786.60	3,809.10	3,834.20	3,859.30	3,886.30	—
Inflation Rate (1967 = 100) (Annualized Rate of Change in Consumer Price Index)														
Lower Price Trend	N/A	1.48	-3.97	3.12	2.10	2.95	2.93	3.28	3.01	3.59	3.44	3.53	3.85	—
Upper Price Trend	N/A	1.48	-2.29	3.41	2.44	3.41	3.30	3.46	3.30	3.92	3.58	3.59	3.85	—
Car Sales, Domestic (Millions)														
Lower Price Trend	N/A	7.90	8.00	7.80	8.10	8.00	7.70	7.40	7.20	7.20	7.10	7.00	7.00	—
Upper Price Trend	N/A	7.90	7.90	7.60	7.90	7.80	7.40	7.10	6.90	6.90	6.80	6.70	6.70	—
Unemployment (Percentage)														
Lower Price Trend	7.00	7.10	7.00	7.00	6.90	7.00	7.00	7.00	7.00	6.80	6.60	6.50	6.40	—
Upper Price Trend	7.00	7.10	7.10	7.10	7.00	7.20	7.30	7.30	7.30	7.10	7.00	6.90	6.90	—

TABLE C-6

LONG-TERM IMPACTS OF NPC PRICE SCENARIOS
LOWER PRICE TREND—4 PERCENT REAL GROWTH IN OIL PRICES FROM $12 IN 1986
(DRI Model)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Average Refiners' Acquisition Price (Dollars per Barrel)																
Crude Oil, Imported	27.04	11.47	12.55	13.74	14.86	16.17	17.67	19.36	21.24	23.35	25.71	28.27	31.07	34.14	37.51	41.20
Percentage Change	-6.3	-56.6	9.4	9.5	8.1	8.9	9.3	9.6	9.7	9.9	10.1	9.9	9.9	9.9	9.9	9.8
Average Refiners' Acquisition Price (Dollars per Barrel)																
Crude Oil, Composite	26.75	12.00	12.74	13.74	14.80	16.07	17.52	19.16	21.00	23.08	25.42	27.96	30.74	33.78	37.13	40.78
Percentage Change	-6.6	-55.2	6.2	7.9	7.7	8.5	9.0	9.4	9.6	9.9	10.1	10.0	9.9	9.9	9.9	9.9
Gross National Product (Billion 1982 $)	3,570.0	3,654.5	3,761.3	3,884.5	3,949.8	4,055.0	4,185.9	4,302.6	4,408.1	4,503.7	4,603.3	4,711.9	4,829.5	4,956.9	5,087.4	5,224.9
Percentage Change	2.2	2.4	2.9	3.3	1.7	2.7	3.2	2.8	2.5	2.2	2.2	2.4	2.5	2.6	2.6	2.7
GNP Price Deflator	1.117	1.147	1.171	1.212	1.257	1.312	1.374	1.442	1.517	1.600	1.688	1.778	1.873	1.972	2.074	2.181
Percentage Change	3.4	2.6	2.2	3.5	3.7	4.3	4.7	5.0	5.2	5.4	5.5	5.4	5.3	5.3	5.2	5.1
Consumer Price Index (All Urban)	3.221	3.264	3.351	3.483	3.619	3.773	3.947	4.142	4.352	4.582	4.836	5.097	5.369	5.650	5.943	6.255
Percentage Change	3.5	1.3	2.7	4.0	3.9	4.3	4.6	4.9	5.1	5.3	5.5	5.4	5.3	5.2	5.2	5.3
Personal Consumption Expenditures (Billion 1982 $)	2,313.0	2,399.5	2,470.4	2,543.1	2,579.4	2,638.9	2,709.7	2,776.3	2,838.5	2,892.8	2,950.3	3,011.8	3,074.6	3,144.3	3,216.9	3,292.2
Percentage Change	3.3	3.7	3.0	2.9	1.4	2.3	2.7	2.5	2.2	1.9	2.0	2.1	2.1	2.3	2.3	2.3
Gross Fixed Private Nonresidential Investment (Billion 1982 $)	472.1	466.5	468.4	489.0	499.9	510.9	538.5	562.7	589.3	618.2	643.9	666.4	692.2	720.2	751.7	784.1
Percentage Change	9.7	-1.2	0.4	4.4	2.2	2.2	5.4	4.5	4.7	4.9	4.2	3.5	3.9	4.0	4.4	4.3
Industrial Production Index	1.245	1.257	1.297	1.351	1.367	1.406	1.464	1.512	1.551	1.589	1.633	1.675	1.724	1.777	1.829	1.884
Percentage Change	2.3	1.0	3.2	4.2	1.2	2.9	4.1	3.3	2.6	2.4	2.8	2.6	2.9	3.1	2.9	3.0
Unit Sales of Automobiles (Millions)	11.1	11.2	11.6	11.6	10.8	10.9	11.2	11.4	11.5	11.5	11.7	11.9	12.1	12.3	12.5	12.6
Percentage Change	7.1	0.4	4.0	-0.6	-6.8	1.2	3.0	1.7	1.0	0.0	1.4	1.7	1.4	1.9	1.3	1.3
Housing Starts, Private Including Farm (Millions)	1.741	1.966	1.827	1.769	1.727	1.685	1.758	1.791	1.778	1.722	1.661	1.618	1.618	1.657	1.697	1.719
Percentage Change	-1.2	12.9	-7.1	-3.2	-2.4	-2.4	4.3	1.9	-0.7	-3.2	-3.5	-2.6	0.0	2.4	2.5	1.3
Unemployment Rate, All Civilian Workers (Percent)	7.20	7.05	6.78	6.46	6.64	4.77	6.59	6.49	6.51	6.64	6.76	6.82	6.82	6.75	6.64	6.51
Average Market Rate on U.S. Gov't. 3-Month Bills (Percent)	7.48	6.13	6.02	5.23	5.36	5.86	6.05	6.08	6.08	6.04	6.00	6.00	5.98	5.96	5.94	5.92
Average Yield on Moody's AAA Corporate Bonds (Percent)	11.37	9.04	8.61	8.08	8.02	8.38	8.41	8.45	8.43	8.34	8.25	8.23	8.21	8.14	8.10	8.08
Exports Of Goods & Services (Net) (Billions of Dollars)	-78.5	-91.3	-73.7	-57.3	-44.1	-27.9	-21.8	-13.5	-11.5	-10.3	-7.4	4.8	19.5	29.7	34.0	39.5
Federal Government Surplus Or Deficit (-), MIA Basis (Billions of Dollars)	-200.0	-191.9	-137.9	-145.0	-132.4	-113.2	-99.8	-97.1	-98.0	-101.6	-109.2	-116.3	-117.1	-114.7	-113.6	-113.7

TABLE C-7

LONG-TERM IMPACTS OF NPC PRICE SCENARIOS
LOWER PRICE TREND—5 PERCENT REAL GROWTH IN OIL PRICES FROM $18 IN 1986
(DRI Model)

	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Average Refiners' Acquisition Price (Dollars per Barrel)																
Crude Oil, Imported	27.04	17.26	18.94	20.95	22.87	25.14	27.73	30.67	33.98	37.70	41.90	46.49	51.55	57.16	63.37	70.23
Percentage Change	-6.3	-36.2	9.8	10.6	9.2	9.9	10.3	10.6	10.8	11.0	11.1	11.0	10.9	10.9	10.9	10.8
Average Refiners' Acquisition Price (Dollars per Barrel)																
Crude Oil, Composite	26.75	18.00	19.23	20.95	22.79	24.98	27.49	30.36	33.59	37.27	41.43	45.98	51.01	56.57	62.72	69.52
Percentage Change	-6.6	-32.7	6.8	8.9	8.8	9.6	10.1	10.4	10.6	10.9	11.2	11.0	10.9	10.9	10.9	10.8
Gross National Product (Billion 1982 $)	3,570.0	3,653.4	3,752.0	3,855.0	3,913.4	4,018.9	4,158.3	4,279.4	4,390.9	4,495.0	4,597.8	4,702.7	4,812.7	4,930.0	5,046.8	5,168.0
Percentage Change	2.2	2.3	2.7	2.7	1.5	2.7	3.5	2.9	2.6	2.4	2.3	2.3	2.3	2.4	2.4	2.4
GNP Price Deflator	1.117	1.147	1.178	1.226	1.276	1.334	1.400	1.472	1.551	1.638	1.732	1.830	1.933	2.042	2.154	2.271
Percentage Change	3.4	2.6	2.7	4.1	4.1	4.5	4.9	5.2	5.4	5.6	5.7	5.7	5.7	5.6	5.5	5.4
Consumer Price Index (All Urban)	3.221	3.295	3.417	3.573	3.729	3.903	4.095	4.307	4.537	4.788	5.067	5.358	5.664	5.982	6.316	6.671
Percentage Change	3.5	2.3	3.7	4.6	4.4	4.7	4.9	5.2	5.3	5.6	5.8	5.7	6.7	5.6	6.6	5.6
Personal Consumption Expenditures (Billion 1982 $)	2,313.0	2,386.0	2,439.6	2,502.4	2,538.8	2,597.4	2,669.2	2,736.7	2,801.1	2,859.5	2,920.3	2,982.8	3,044.6	3,112.2	3,181.0	3,251.4
Percentage Change	3.3	3.2	2.2	2.6	1.5	2.3	2.8	2.5	2.4	2.1	2.1	2.1	2.1	2.2	2.2	2.2
Gross Fixed Private Nonresidential Investment (Billion 1982 $)	472.1	469.8	473.7	489.6	496.3	507.8	537.3	559.1	587.7	619.6	645.4	666.0	689.2	714.3	741.6	769.0
Percentage Change	9.7	-0.5	0.8	3.4	1.4	2.3	5.8	4.1	5.1	5.4	4.2	3.2	3.5	3.6	3.8	3.7
Industrial Production Index	1.245	1.252	1.281	1.319	1.328	1.365	1.426	1.477	1.518	1.558	1.601	1.639	1.682	1.728	1.771	1.816
Percentage Change	2.3	0.5	2.3	3.0	0.6	2.8	4.5	3.5	2.8	2.7	2.7	2.4	2.6	2.7	2.5	2.5
Unit Sales of Automobiles (Millions)	11.1	10.9	10.9	10.8	10.3	10.5	11.0	11.2	11.4	11.4	11.6	11.8	11.9	12.1	12.3	12.4
Percentage Change	7.1	-2.2	0.5	-1.4	-4.2	2.0	4.2	2.2	1.3	0.5	1.7	1.6	1.2	1.7	1.0	1.0
Housing Starts, Private Including Farm (Millions)	1.741	1.943	1.748	1.697	1.667	1.637	1.740	1.801	1.792	1.740	1.677	1.625	1.617	1.647	1.681	1.697
Percentage Change	-1.2	11.6	-10.0	-2.9	-1.8	-1.8	6.2	3.5	-0.5	-2.9	-3.6	-3.1	-0.5	1.9	2.0	1.0
Unemployment Rate, All Civilian Workers (Percent)	7.20	7.06	6.84	6.66	6.94	7.05	6.77	6.56	6.51	6.53	6.59	6.65	6.69	6.68	6.64	6.60
Average Market Rate on U.S. Gov't. 3-Month Bills (Percent)	7.48	6.24	6.33	5.67	5.88	6.44	6.45	6.39	6.37	6.33	6.31	6.30	6.29	6.27	6.26	6.25
Average Yield on Moody's AAA Corporate Bonds (Percent)	11.37	9.13	8.92	8.44	8.53	8.97	8.94	8.90	8.85	8.75	8.69	8.69	8.70	8.67	8.66	8.69
Exports Of Goods & Services (Net) (Billions of Dollars)	-78.5	-98.8	-72.7	-58.9	-50.4	-37.8	34.2	-28.6	-30.4	-34.2	-37.1	-30.9	-24.1	-24.0	-33.1	-43.0
Federal Government Surplus Or Deficit (-), MIA Basis (Billions of Dollars)	-200.0	-192.0	-145.3	-160.8	-153.2	-136.4	-20.0	-114.6	-113.0	-113.5	-121.8	-132.6	-139.2	-144.1	-153.7	-167.5

APPENDIX D

NPC OIL & GAS OUTLOOK SURVEY AND ADDITIONAL DATA ON EXPLORATION, PRODUCTION, AND RESERVES

Provisos Regarding the NPC Survey of Oil & Gas Outlook

The NPC Oil & Gas Outlook Survey requested detailed energy outlooks for the U.S. and non-communist world under two price trends provided by the DOE in the attached letter of May 14, 1986. The upper price trend starts at an average refiner crude oil acquisition price of $18 per barrel in 1986, rising 5 percent per year in real terms to $36 per barrel in the year 2000. The lower price trend starts at $12 per barrel in 1986, rising 4 percent per year in real terms to $21 per barrel in 2000.

The analysis of the survey responses was complicated by the varying degree of detail provided among the responses. While 52 questionnaires were distributed, 28 of the 33 responses received were in a usable form.

Even sophisticated statistical analysis of past events is inadequate for predicting the future if the historical data do not contain an event similar to the current or expected future events. This limitation is reflected in this survey. Energy forecasters have no recent historical events to measure the impact of sharply falling prices of petroleum, nor has there been a period in history when the price of petroleum grew in real terms at a 4 to 5 percent rate for fifteen years.

Fewer forecasts were received for the lower price trend. A number of respondents indicated that their proprietary models yielded results that were unacceptable or that their models could not reach a feasible solution in the later years in the lower price case.

Despite the difficulties experienced by some forecasters in developing "reasonable" responses to the two price outlooks provided, the general story told by the responses of experts is consistent as to direction if not as to the absolute level of specific variables. Both the domestic supply and demand of oil and gas are responsive to economic forces. Low prices stimulate demand and retard supply, and the reverse is true for higher prices. Hence the survey responses are not unreasonable in projecting higher oil imports in the lower price trend than in the upper price trend, although individual respondents and others may disagree with the projected level of oil imports in the later years.

Department of Energy
Washington, DC 20585

May 14, 1986

Mr. James L. Ketelsen
Chairman and Chief Executive Officer
Tenneco Incorporated
Tenneco Building
Post Office Box 2511
Houston, TX 77001

Dear Mr. Ketelsen:

Immediately following the April 22, 1986, meeting of the National Petroleum Council (NPC) Committee on U.S. Oil and Gas Outlook, the Coordinating Subcommittee met. A prime agenda item was to discuss critical path items for the study examining the primary factors affecting the Nation's future supply and demand of oil and gas.

It was agreed that the Department of Energy would provide two oil price cases intended to suggest a range of plausible prices as assumptions for the purpose of this study. In response, we would propose the following simplified cases:

1. Case A -- Starting at $12 per barrel in 1986 and increasing by four percent per year to about $21 per barrel in the year 2000.

2. Case B -- Starting at $18 per barrel in 1986 and increasing by five percent per year to about $36 per barrel in the year 2000.

These oil prices are expressed in 1986 dollars and should be interpreted as the U.S. Composite Refiner Acquisition Cost.

We appreciate the efforts of you and the other NPC members on this most important study.

Sincerely,

Donald L. Bauer

Donald L. Bauer
Acting Assistant Secretary
for Fossil Energy

cc:
Marshall Nichols

INSTRUCTIONS

NPC SURVEY OF U.S. AND WORLD ENERGY AND OIL SUPPLY/DEMAND FORECASTS

Please return surveys by June 16, 1986 to:

John H. Guy, IV
Deputy Executive Director
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

This survey is being conducted by the Future Supply/Demand Factors Task Group of the National Petroleum Council Committee on U.S. Oil and Gas Outlook. The responses will be analyzed and consolidated, if possible, by the Task Group into consensus forecasts based upon the price trends provided. No individual forecasts will be identified in the NPC report. However, the survey responses will become part of the permanent record of the study and will be available for public inspection in the NPC offices.

There are two sets of forms for each of the following tables, one for each of the price trends, upper and lower:

I. Non-Communist World Oil Supply/Demand Balance.
II. Total U.S. energy consumption by fuels and by consuming sectors.
III. U.S. liquid fuels and natural gas supplies.
   A. U.S. crude and condensate production.
   B. U.S. marketed natural gas production.
IV. Proved U.S. oil and gas reserves.

Each table requests data for 1990, 1995 and 2000. Preliminary 1985 (or 1984) actuals have been provided by the DOE as a guide. (These numbers are generally consistent with the data in the Monthly Energy Review of January 1986). Respondents are encouraged, if they are unable to resolve definitional differences between their data and that reflected in the 1985 estimates, to provide their own 1985 estimate.

Note that the forms are generally designed to allow completion at varying levels of detail. We will use the responses at whatever level you are able to provide.

Please note that, especially for the details of U.S. supply in Tables III A and B, the impact of the change from the high to the low price trend is more significant than the absolute level of any subcategory.

It is important to note the accompanying assumptions, especially the two price trend cases. These are simplified trends provided by the DOE for purposes of this study. They are not forecasts of future prices, but are intended to suggest a range of plausible prices, and more importantly, provide insight into the impact of lower prices on the oil and gas outlook.

Please provide the gas prices that you feel would prevail consistent with these two oil price trends and the rationale utilized to arrive at such gas prices.

It is further requested that you return with the completed survey forms any explanatory notes you feel necessary for an accurate interpretation of the forecast data you supply, as well as any significant differences in assumptions.

Please use existing forecasts whenever available. We recognize additional work will be necessary in some cases to provide reasonable estimates for the survey.

In order to expedite the processing of your response, leave blank any question you are unable to answer. If you wish to indicate zero quantity for a product, insert a "0." A negative quantity should be bracketed, i.e., (159). Only provide information for the categories indicated on the tables. If you wish to supply information not requested in the tables, please attach additional sheets. Also, please use the units indicated on the table when completing the survey. If your data is in a different form, please provide conversion factors and note the units used on the table.

Table II in the attached questionnaire requests consumption in the form of Btu equivalents. Some respondents may forecast petroleum liquids consumption in barrels. These should be converted to Btu equivalents as follows:

1. If petroleum liquids are forecast within sectors by individual product barrels, then convert to Btu equivalents using the enclosed EIA Conversion Factors.

2. If petroleum liquids are forecast within sectors by total barrels only, then use the following composite conversion factors based on 1985 data:

	Million Btu/BBL
Transportation	5.42
Residential/Commercial	5.25
Industrial	5.66
Electrical Generation	6.24
Non-Energy	4.93

These tables are prepared on Lotus 1-2-3 spreadsheets (version 1A or version 2), and a disk with the blank worksheets and summation formulas is included to expedite your response if desired. The instructions and description of the worksheets are contained on the disk in a file which can be printed by the DOS 2.0+ (IBM PC or compatible) command PRINT d:README where d: is the diskette drive specification.

Please include the name and phone number of the individual in your organization to be contacted if any questions arise as we review the completed forms. Company identification is encouraged, but if you are not willing to submit responses on this basis, please submit your response with a simple classification of your firm, e.g., oil or gas, consulting, financial, etc., and no other identification.

If any questions arise regarding the survey, please contact Mr. John H. Guy IV, Deputy Executive Director, National Petroleum Council, 1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100.

PRICE ASSUMPTIONS

In order to provide background for a range of plausible future U.S. oil and gas outlooks (and recognizing there are considerable studies available based on prices prevailing in 1985), the Department of Energy has provided two simplified price trends:

World Oil Prices*
1986 $/Bbl.

	1986	1990	1995	2000
Upper Price Trend (5%/Year Growth)	18	22	28	36
Lower Price Trend (4%/Year Growth)	12	14	17	21

*U.S. Composite Refiner Acquisition Cost

There are many possible price paths which could occur between now and 2000. It is hoped that these will provide a basis for U.S. oil and gas outlooks which will be useful in identifying the critical factors behind the future outlooks, and at the same time, be neutral trends which will allow individual submissions without concern for submission of proprietary forecasts.

The upper price trend is consistent with scenarios where it is assumed that OPEC countries act quickly to stabilize world oil prices by constraining production, and continue to adjust production to balance market share and revenue interests.

The lower price trend is consistent with scenarios where it is assumed that OPEC production is relatively unconstrained, but demand is lower due to, for example, competition from alternative fuels and continued conservation.

While the lower trend is plausible, many forecasters may feel that without very special circumstances, the supply/demand pressures after a period of time would force an increase in the price in order to avert shortages. While we do not wish to require another set of survey responses, it would be useful if respondents do have an estimate of the timing and rate of increase which might occur in such a "bounce-back," they describe this on the last page of the assumptions.

OTHER BASIC ASSUMPTIONS

The following are assumptions that should be used when developing the future energy supply/demand scenarios for both the high and low price trend. When extrapolating figures from recent company in-house forecasts, after trying to make forecasts consistent with these assumptions, if major differences in assumptions still exist for either the high or low price trend, please note those differences in the space provided on the next page.

1. Economic: U.S.

   Real GNP growth is expected to move along a stable trend path with continued modest inflation.

   Please specify your assumed rates for:

	Actual 1985	1990 Over 1985	1995 Over 1990	2000 Over 1995
a. Real GNP				
High Price Trend	2.2	___	___	___
Low Price Trend	2.2	___	___	___
b. Price Inflation (GNP Price Deflator)				
High Price Trend	3.3	___	___	___
Low Price Trend	3.3	___	___	___

2. Financial

   a. No dramatic change in exchange rates between the world's currencies.

   b. No worldwide banking or financial crises.

3. Government

   a. Domestically, no change in present laws, e.g., no early deregulation of natural gas, no early phase out of Windfall Profits Tax, continuation of current tax law.

   b. Current environmental regulations will continue as presently designated.

   c. Leasing policies as presently constituted will continue.

4. Political

   a. Domestically, no unforeseen events not presently planned for are assumed.

   b. Internationally, no drastic changes in the world are assumed, such as new major wars, revolutions or the end of OPEC.

5. Technological

   a. No new major technological breakthroughs in either the production or consumption of energy.

   b. Refining capacity will be adequate at all times to allow for conversion of oil to meet light product demand.

6. Conservation and Fuel Use

   Please provide any comments on your assumptions affecting energy efficiency, especially:

   a. Automobile efficiency/fleet average.

   b. Major assumptions impacting the use of different forms of energy.

   c. Electricity growth rates and treatment of cogeneration (if not as a primary fuel input by sector).

7. Please highlight specific (step function) assumption changes between the upper and low price trend cases.

If there are any significant deviations from these assumptions that result in substantial changes in the supply or demand for oil or gas, then those exceptions should be noted below.

Conversion Factors

Approximate Heat Content of Petroleum Products

	Million Btu per Barrel
Asphalt	6.636
Aviation gasoline	5.048
Butane	4.326
Butane-propane mixture[1]	4.130
Distillate fuel oil	5.825
Ethane	3.082
Ethane-propane mixture[2]	3.308
Isobutane	3.974
Jet fuel—kerosene type	5.670
Jet fuel—naphtha type	5.355
Kerosene	5.670
Lubricants	6.065
Motor gasoline	5.253
Natural gasoline	4.620
Pentanes Plus	4.620
Petrochemical feedstocks	
Naphtha 400°F or less	5.248
Other oils over 400°F	5.825
Still gas	6.000
Petroleum coke	6.024
Plant condensate	5.418
Propane	3.836
Residual fuel oil	6.287
Road oil	6.636
Special naphtha	5.248
Still gas	6.000
Unfinished oils	5.825
Unfractionated stream	5.418
Wax	5.537
Miscellaneous	5.796

[1]60 percent butane and 40 percent propane.
[2]70 percent ethane and 30 percent propane.

NATIONAL PETROLEUM COUNCIL
SURVEY OF U.S. AND WORLD ENERGY
AND OIL SUPPLY/DEMAND FORECASTS

Cover Page

Reporting Organization: ______________________________

Address: ______________________________

____

Date Internal Forecast Prepared: ______________________________

Person to be Contacted
if Questions Arise: ______________________________

Telephone Number: ______________________________

Please return by June 16, 1986: John H. Guy, IV
Deputy Executive Director
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

TABLE D-1

UPPER PRICE TREND
NON-COMMUNIST WORLD OIL SUPPLY /DEMAND BALANCE
(Thousand Barrels Per Day)

	Actual 1985	1990	1995	2000
Consumption				
United States	15,726	16,331	17,004	17,403
Western Europe	11,673	11,891	12,116	12,362
Japan	4,336	4,531	4,658	4,667
Other OECD	2,543	2,562	2,635	2,712
Rest of World*	12,170	12,883	14,061	15,306
Total Consumption	**46,448**	**48,198**	**50,474**	**52,450**
Supply				
Non-OPEC Crude & Condensate Production†				
United States	8,971	7,959	6,990	6,353
Canada (excluding tar sands)	1,296	1,265	1,252	1,182
Mexico	2,735	3,015	3,351	3,664
Western Europe	3,750	3,515	3,100	2,636
Other Non-OPEC	5,759	6,380	6,624	6,296
Total Non-OPEC Crude & Condensate	22,511	22,134	21,317	20,131
Non-OPEC NGL Production	2,696	2,592	2,586	2,388
OPEC Crude & Condensate Production†				
Ecuador	278	274	260	234
Venezuela	1,674	1,855	1,992	1,967
Algeria	643	690	724	706
Gabon	153	147	134	117
Libya	1,059	1,218	1,399	1,483
Nigeria	1,471	1,724	1,798	1,795
Iran	2,201	2,344	2,887	3,117
Iraq	1,433	2,175	2,663	3,161
Kuwait	846	1,065	1,395	1,821
Qatar	301	327	396	409
United Arab Emirates	1,193	1,307	1,618	2,030
Saudi Arabia	3,218	4,471	5,554	7,374
Neutral Zone	340	347	422	455
Indonesia	1,258	1,374	1,314	1,250
Total OPEC Crude & Condensate	16,068	19,318	22,556	25,919
OPEC NGL Production	1,110	1,301	1,400	1,600
Total Crude, Cond., & NGL Production	42,385	45,345	47,859	50,038
Tar Sands, Shale & Other Syn. Fuels	436	488	592	713
Refinery Gains & Inventory Change‡	1,330	874	924	930
Net Imports from Comm. Countries	1,804	1,491	1,099	769
Total Oil Supply	**45,955**	**48,198**	**50,474**	**52,450**
Errors & Omissions	493	0	0	0

*Includes OPEC, middle income countries, and the less developed countries.
†Does not include tar sands, shale, and other synthetics, which are reported below.
‡Includes strategic reserves.

TABLE D-2

UPPER PRICE TREND
TOTAL U.S. ENERGY CONSUMPTION BY FUELS AND BY CONSUMING SECTORS
(Trillion BTU Per Year)

	Primary Energy Inputs to Sector*									
	Petroleum Liquids	Natural Gas (Dry)	Coal	Nuclear	Hydro-Electric	Geo-Thermal	Other†	Total Primary Energy	Electricity Distributed to Sector	Energy‡ Consumption
Total*										
Actual 1985	30,922	17,868	17,488	4,160	2,871	97	3,242	76,648	—	76,648
1990	32,189	18,128	19,178	5,915	3,465	154	3,152	82,181	—	82,181
1995	33,520	17,826	22,038	6,169	3,480	199	3,336	86,568	—	86,568
2000	34,328	17,485	25,318	6,210	3,540	238	3,444	90,563	—	90,563
Residential /Commercial										
Actual 1985	2,584	7,063	181	—	—	—	1,070	10,898	5,055	15,953
1990	2,656	7,267	195	—	—	—	939	11,057	5,646	16,703
1995	2,630	7,238	195	—	—	—	958	11,021	6,242	17,263
2000	2,534	7,310	200	—	—	—	953	10,997	6,746	17,743
Transportation										
Actual 1985	19,548	526	—	—	—	—	—	20,074	12	20,086
1990	20,200	550	—	—	—	—	—	20,750	13	20,763
1995	20,800	535	—	—	—	—	—	21,335	15	21,350
2000	21,200	525	—	—	—	—	—	21,725	15	21,740
Industrial										
Actual 1985	3,900	7,128	2,658	—	—	—	1,740	15,426	2,813	18,239
1990	4,262	7,487§	2,916	—	—	—	1,715	16,380	3,255	19,635
1995	4,629	7,396§	3,246	—	—	—	1,739	17,010	3,692	20,702
2000	4,781	7,327§	3,650	—	—	—	1,781	17,539	4,136	21,675
Electric Utility										
Actual 1985	1,090	3,151	14,549	4,160	2,871	97	432	26,350	(7,880)	18,470
1990	1,066	2,824	15,984	5,915	3,465	154	498¶	29,906	(8,914)	20,992
1995	1,210	2,657	18,509	6,169	3,480	199	639¶	32,863	(9,949)	22,914
2000	1,297	2,323	21,374	6,210	3,540	238	710¶	35,692	(10,897)	24,795
Non-Energy & Others**										
Actual 1985	3,800	—	100	—	—	—	—	3,900	—	3,900
1990	4,005	—	83	—	—	—	—	4,088	—	4,088
1995	4,251	—	88	—	—	—	—	4,339	—	4,339
2000	4,516	—	94	—	—	—	—	4,610	—	4,610

*Standard Conversion Factors—Petroleum Liquids (total): See conversion table on page D-8; Natural Gas: 1,030 BTU/Cubic Foot; Coal: 21.4 MMBTU/Short Ton; Nuclear, Hydro, Geothermal, Imports: 10,400 BTU/KWH (equiv. fuel input in steam plant); Electricity Distributed: 3,412 BTU/KWH.

†Solar/Wood/Other.

‡Energy consumption equals primary energy inputs plus electricity distributed for all sectors, except "Electric Utility." For electric utility sector, energy consumption equals total primary energy less electricity distributed. Include cogeneration under the sector operating the facility.

§Include lease and plant gas.

¶Include electricity net imports as if generated by utility.

**Include synthetic fuel production conversion losses (if any) and Products Reclassified (a negative adjustment).

TABLE D-3

UPPER PRICE TREND
U.S. LIQUID FUELS AND NATURAL GAS SUPPLIES

	Actual 1985	1990	1995	2000
Oil (Thousand Barrels Per Day)				
Domestic Production—Total	10,580	9,359	8,259	7,495
Crude Oil & Lease Condensate	8,971	7,959	6,990	6,353
Natural Gas Liquids	1,609	1,400	1,269	1,142
Net Imports*	4,168	6,214	7,937	9,068
Gross Imports—Total	4,949	6,905	8,617	9,667
Crude Oil*	3,083	4,605	5,917	6,667
Products†	1,866	2,300	2,700	3,000
Gross Exports—Total	(781)	(691)	(680)	(599)
Processing Gain, etc.‡	702	709	738	750
Synthetic Liquids§	55	49	70	90
From (To) Inventory*	221	0	0	0
Total Oil Supply	**15,726**	**16,331**	**17,004**	**17,403**
Gas (Billion Cubic Feet Per Year)				
Net Dry Gas Production	16,382	16,356	15,187	14,455
Marketed Production of Wet Gas¶	17,198	17,127	15,902	15,136
Extraction Loss, Transfers Out	(816)	(771)	(715)	(681)
Gross Imports—Total	950	1,344	2,220	2,616
Canada	926	1,344	2,095	2,196
Mexico	0	0	125	220
Liquefied Natural Gas	24	0	0	200
Gross Exports—Total	(57)	(55)	(55)	(55)
From (To) Inventory (Transmission Loss & Unaccounted)	(120)	(245)	(245)	(240)
Total Dry Natural Gas	17,155	17,400	17,107	16,776
Syngas & Other Supplemental Gaseous Fluids	126	200	200	200
Total Gas Supply	**17,281**	**17,600**	**17,307**	**16,976**

*Deduct crude oil supplied to the SPR (118 MB/D in 1985).

†Includes NGL, alcohol, and other unfinished.

‡Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude oil inputs and losses.

§Includes tar sands, shale, alcohols, and other synthetic fuels.

¶Excludes quantities for repressuring, vented and flared.

TABLE D-4

UPPER PRICE TREND
U.S. CRUDE OIL AND CONDENSATE PRODUCTION
(Thousand Barrels Per Day)

	Actual 1985	1990	1995	2000
Existing Fields	**8,971**	**7,683**	**6,391**	**5,260**
Developed Production*	8,421	5,351	3,577	2,173
Lower 48	6,596	3,972	2,582	1,511
Onshore	5,364	3,209	2,058	1,218
Offshore	1,232	763	524	293
Alaska	1,825	1,379	995	662
New Investment†	—	1,727	2,104	2,239
Lower 48	—	1,507	1,764	1,853
Onshore	—	1,124	1,352	1,477
Offshore	—	383	412	376
Alaska	—	220	340	386
Enhanced Oil Recovery‡	550 est.	605	710	848
Lower 48	550 est.	574	672	782
Onshore	532 est.	552	640	718
Offshore	18 est.	22	32	64
Alaska	0	31	38	66
New Discoveries§	**—**	**276**	**599**	**1,093**
Lower 48	—	276	499	771
Onshore	—	187	322	504
Offshore	—	89	177	267
Alaska	—		100	322
Memo: Stripper¶	1,270	1,096	988	884
Total	**8,971**	**7,959**	**6,990**	**6,353**

*Excludes EOR projects in production before January 1, 1986. Includes recompletions, workovers, and normal maintenance.

†Extensions, development drilling, infill drilling, and new pools in known fields since January 1, 1986. Excludes new investment in EOR.

‡Includes production from EOR projects in place prior to January 1, 1986, and new EOR projects added to known (1985) fields after January 1, 1986.

§Includes all recovery production, including EOR, from new discoveries since January 1, 1986.

¶Included as portion of developed production. The data used were for January 1, 1985.

TABLE D-5

UPPER PRICE TREND
U.S. MARKETED NATURAL GAS PRODUCTION
(Billion Cubic Feet Per Year)

	Actual 1985	1990	1995	2000
Existing Fields	**17,198**	**15,793**	**13,041**	**10,888**
Developed Production*	17,198	11,240	7,062	4,471
Lower 48	16,877	10,950	6,787	4,221
Onshore	12,245	7,968	5,060	3,194
Offshore	4,632	2,982	1,727	1,027
Alaska	321	290	275	250
New Investment†		4,553	5,979	6,417
Lower 48		4,503	5,904	6,317
Onshore		2,613	3,409	3,846
Offshore		1,890	2,495	2,471
Alaska		50	75	100
New Discoveries‡		**1,334**	**2,861**	**4,248**
Lower 48		1,334	2,851	4,218
Onshore		716	1,455	2,367
Offshore		618	1,396	1,851
Alaska		0	10	30
Total	**17,198**	**17,127**	**15,902**	**15,136**

*Includes recompletions, workovers, and normal maintenance.

†Extensions, development drilling, infill drilling, and new pools in known fields since January 1, 1986.

‡Includes all recovery/production from new discoveries since January 1, 1986.

TABLE D-6

UPPER PRICE TREND
PROVED U.S. OIL AND GAS RESERVES*
(as of December 31st)

	Actual 1985	1990	1995	2000
Total				
Crude Oil (billion barrels)	28.4	23.2	18.5	17.6
Natural Gas Liquids (billion barrels)	7.94	5.3	4.5	4.2
Natural Gas—Dry (TCF)†	193.4	166.9	151.9	141.5
Onshore (Lower 48)				
Crude Oil (billion barrels)	17.8	13.8	11.0	10.4
Natural Gas Liquids (billion barrels)	6.81	4.5	3.8	3.5
Natural Gas—Dry (TCF)†	122.2	94.3	81.0	73.5
Offshore (Lower 48)				
Crude Oil (billion barrels)	3.5	3.3	2.9	2.9
Natural Gas Liquids (billion barrels)	0.75	0.8	0.7	0.7
Natural Gas—Dry (TCF)†	37.3	38.6	37.3	34.4
Alaska				
Crude Oil (billion barrels)	7.1	6.1	4.6	4.3
Natural Gas Liquids (billion barrels)	0.38	0.01	0.01	0.01
Natural Gas—Dry (TCF)†	33.9	34.0	33.6	33.6
Memo: (in millions)				
Cumulative footage drilled from 1/1/86		1,176	2,592	4,258
Cumulative wells drilled from 1/1/86		.236	.516	.849

*Assumptions consistent with those used by the Energy Information Agency publication DOE/EIA-0216(85).

†TCF = trillion cubic feet.

TABLE D-7

LOWER PRICE TREND
NON-COMMUNIST WORLD OIL SUPPLY/DEMAND BALANCE
(Thousand Barrels Per Day)

	Actual 1985	1990	1995	2000
Consumption				
United States	15,726	17,625	18,977	19,938
Western Europe	11,673	12,681	13,269	13,861
Japan	4,336	4,845	5,044	5,284
Other OECD	2,543	2,657	2,833	3,031
Rest of World*	12,170	13,193	14,527	15,870
Total Consumption	**46,448**	**51,000**	**54,650**	**57,984**
Supply				
Non-OPEC Crude & Condensate Production†				
United States	8,971	7,136	5,654	4,542
Canada (excluding tar sands)	1,296	1,073	1,033	978
Mexico	2,735	2,980	3,203	3,446
Western Europe	3,750	3,343	2,584	2,041
Other Non-OPEC	5,759	5,443	5,578	5,433
Total Non-OPEC Crude & Condensate	22,511	19,975	18,052	16,440
Non-OPEC Natural Gas Liquid Production	2,696	2,464	2,367	2,158
OPEC Crude & Condensate Production†				
Ecuador	278	289	256	245
Venezuela	1,674	1,929	2,129	2,122
Algeria	643	770	781	776
Gabon	153	163	160	160
Libya	1,059	1,345	1,520	1,606
Nigeria	1,471	1,841	1,879	1,900
Iran	2,201	2,725	3,350	3,901
Iraq	1,433	2,734	3,406	4,184
Kuwait	846	1,398	1,823	2,264
Qatar	301	390	417	406
United Arab Emirates	1,193	1,567	1,962	2,264
Saudi Arabia	3,218	7,221	10,438	13,228
Neutral Zone	340	424	481	483
Indonesia	1,258	1,535	1,526	1,520
Total OPEC Crude & Condensate	16,068	24,331	30,128	35,059
OPEC Natural Gas Liquid Production	1,110	1,446	1,694	1,961
Total Crude, Cond., & NGL Production	42,385	48,216	52,241	55,618
Tar Sands, Shale & Other Syn. Fuels	436	424	499	605
Refinery Gains & Inventory Change‡	1,330	958	949	975
Net Imports from Comm. Countries	1,804	1,403	961	786
Total Oil Supply	**45,955**	**51,001**	**54,650**	**57,984**
Errors & Omissions	493	0	0	0

*Includes OPEC, middle income countries, and the less developed countries.

†Does not include tar sands, shale, and other synthetics, which are reported below.

‡Includes strategic reserves.

TABLE D-8

LOWER PRICE TREND
TOTAL U.S. ENERGY CONSUMPTION BY FUELS AND BY CONSUMING SECTORS
(Trillion BTU Per Year)

	Primary Energy Inputs to Sector*									
	Petroleum Liquids	Natural Gas (Dry)	Coal	Nuclear	Hydro-Electric	Geo-Thermal	Other†	Total Primary Energy	Electricity Distributed to Sector	Energy‡ Consumption
Total*										
Actual 1985	30,922	17,868	17,488	4,160	2,871	97	3,242	76,648	—	76,648
1990	34,779	17,460	19,268	5,915	3,465	124	3,152	84,163	—	84,163
1995	37,502	15,960	22,437	6,169	3,480	176	3,336	89,060	—	89,060
2000	39,449	15,426	25,262	6,210	3,540	216	3,444	93,547	—	93,547
Residential/Commercial										
Actual 1985	2,584	7,063	181	—	—	—	1,070	10,898	5,055	15,953
1990	2,855	7,330	195	—	—	—	939	11,319	5,731	17,050
1995	2,947	7,312	197	—	—	—	958	11,414	6,359	17,773
2000	2,923	7,417	189	—	—	—	953	11,482	7,026	18,508
Transportation										
Actual 1985	19,548	526	—	—	—	—	—	20,074	12	20,086
1990	21,100	525	—	—	—	—	—	21,625	13	21,638
1995	22,000	480	—	—	—	—	—	22,480	16	22,496
2000	23,000	465	—	—	—	—	—	23,465	18	23,483
Industrial										
Actual 1985	3,900	7,128	2,658	—	—	—	1,740	15,426	2,813	18,239
1990	4,805	7,313§	2,829	—	—	—	1,715	16,662	3,306	19,968
1995	5,617	6,538§	3,207	—	—	—	1,739	17,101	3,795	20,896
2000	6,118	6,152§	3,393	—	—	—	1,781	17,444	4,315	21,759
Electric Utility										
Actual 1985	1,090	3,151	14,549	4,160	2,871	97	432	26,350	(7,880)	18,470
1990	1,954	2,292	16,171	5,915	3,465	124	498¶	30,419	(9,050)	21,369
1995	2,559	1,630	18,953	6,169	3,480	176	639¶	33,606	(10,170)	23,436
2000	2,686	1,392	21,582	6,210	3,540	216	710¶	36,336	(11,359)	24,977
Non-Energy & Others**										
Actual 1985	3,800	—	100	—	—	—	—	3,900	—	3,900
1990	4,065	—	73	—	—	—	—	4,138	—	4,138
1995	4,379	—	80	—	—	—	—	4,459	—	4,459
2000	4,722	—	98	—	—	—	—	4,820	—	4,820

*Standard Conversion Factors—Petroleum Liquids (total): See conversion table on page D-8; Natural Gas: 1,030 BTU/Cubic Foot; Coal: 21.4 MMBTU/Short Ton; Nuclear, Hydro, Geothermal, Imports: 10,400 BTU/KWH (equiv. fuel input in steam plant); Electricity Distributed: 3,412 BTU/KWH.

†Solar/Wood/Other.

‡Energy consumption equals primary energy inputs plus electricity distributed for all sectors, except "Electric Utility." For electric utility sector, energy consumption equals total primary energy less electricity distributed. Include cogeneration under the sector operating the facility.

§Include lease and plant gas.

¶Include electricity net imports as if generated by utility.

**Include synthetic fuel production conversion losses (if any) and Products Reclassified (a negative adjustment).

TABLE D-9

LOWER PRICE TREND
U.S. LIQUID FUELS AND NATURAL GAS SUPPLIES

	Actual 1985	1990	1995	2000
Oil (Thousand Barrels Per Day)				
Domestic Production—Total	10,580	8,420	6,742	5,484
Crude Oil & Lease Condensate	8,971	7,136	5,654	4,542
Natural Gas Liquids	1,609	1,284	1,088	942
Net Imports*	4,168	8,439	11,397	13,608
Gross Imports—Total	4,949	9,139	12,082	14,256
Crude Oil*	3,083	6,439	8,382	9,556
Products†	1,866	2,700	3,700	4,700
Gross Exports—Total	(781)	(700)	(685)	(648)
Processing Gain, etc.‡	702	725	793	800
Synthetic Liquids§	55	41	45	46
From (To) Inventory*	221	0	0	0
Total Oil Supply	**15,726**	**17,625**	**18,977**	**19,938**
Gas (Billion Cubic Feet Per Year)				
Net Dry Gas Production	16,382	15,459	13,345	12,426
Marketed Production of Wet Gas¶	17,198	16,187	13,974	13,011
Extraction Loss, Transfers Out	(816)	(728)	(629)	(585)
Gross Imports—Total	950	1,582	2,220	2,616
Canada	926	1,582	2,095	2,281
Mexico	0	0	125	300
Liquefied Natural Gas	24	0	0	35
Gross Exports—Total	(57)	(55)	(55)	(55)
From (To) Inventory (Transmission Loss & Unaccounted)	(120)	(235)	(215)	(210)
Total Dry Natural Gas	17,155	16,751	15,295	14,777
Syngas & Other Supplemental Gaseous Fluids	126	200	200	200
Total Gas Supply	**17,281**	**16,951**	**15,495**	**14,977**

*Deduct crude oil supplied to the SPR (118 MB/D in 1985).

†Includes NGL, alcohol, and other unfinished.

‡Includes other hydrocarbon and hydrogen refinery inputs, "unaccounted for" crude oil inputs and losses.

§Includes tar sands, shale, alcohols, and other synthetic fuels.

¶Excludes quantities for repressuring, vented and flared.

TABLE D-10

LOWER PRICE TREND
U.S. CRUDE OIL AND CONDENSATE PRODUCTION
(Thousand Barrels Per Day)

	Actual 1985	1990	1995	2000
Existing Fields	**8,971**	**7,020**	**5,380**	**4,004**
Developed Production*	8,421	5,373	3,599	2,130
Lower 48	6,596	3,954	2,543	1,489
Onshore	5,364	3,184	2,006	1,185
Offshore	1,232	770	537	304
Alaska	1,825	1,419	1,056	641
New Investment†	—	1,182	1,387	1,492
Lower 48	—	1,076	1,208	1,294
Onshore	—	780	900	963
Offshore	—	296	308	331
Alaska	—	106	179	198
Enhanced Oil Recovery‡	550 est.	465	394	382
Lower 48	550 est.	448	377	359
Onshore	532 est.	436	365	342
Offshore	18 est.	12	12	17
Alaska	0	17	17	23
New Discoveries§	**—**	**116**	**274**	**538**
Lower 48	—	116	237	458
Onshore	—	60	138	289
Offshore	—	56	99	169
Alaska	—		37	80
Memo: Stripper¶	1,270	901	626	468
Total	**8,971**	**7,136**	**5,654**	**4,542**

*Excludes EOR projects in production before January 1, 1986. Includes recompletions, workovers and normal maintenance.

†Extensions, development drilling, infill drilling, and new pools in known fields since January 1, 1986. Excludes new investment in EOR.

‡Includes production from EOR projects in place prior to January 1, 1986, and new EOR projects added to known (1985) fields after January 1, 1986.

§Includes all recovery production, including EOR, from new discoveries since January 1, 1986.

¶Included as portion of developed production. The data used were for January 1, 1985.

TABLE D-11

LOWER PRICE TREND
U.S. MARKETED NATURAL GAS PRODUCTION
(Billion Cubic Feet Per Year)

	Actual 1985	1990	1995	2000
Existing Fields	**17,198**	**15,225**	**11,914**	**10,090**
Developed Production*	17,198	11,180	6,735	4,145
Lower 48	16,877	10,890	6,460	3,895
Onshore	12,245	7,894	4,772	2,899
Offshore	4,632	2,996	1,688	996
Alaska	321	290	275	250
New Investment†		4,045	5,179	5,945
Lower 48		3,995	5,104	5,845
Onshore		1,840	2,832	3,335
Offshore		2,155	2,272	2,510
Alaska		50	75	100
New Discoveries‡		**962**	**2,060**	**2,921**
Lower 48		962	2,050	2,891
Onshore		491	957	1,547
Offshore	471	1,093	1,344	
Alaska		0	10	30
Total	**17,198**	**16,187**	**13,974**	**13,011**

*Includes recompletions, workovers, and normal maintenance.

†Extensions, development drilling, infill drilling, and new pools in known fields since January 1, 1986.

‡Includes all recovery/production from new discoveries since January 1, 1986.

TABLE D-12

LOWER PRICE TREND
PROVED U.S. OIL AND GAS RESERVES*
(as of December 31st)

	Actual 1985	1990	1995	2000
Total				
Crude Oil (billion barrels)	28.4	20.2	14.6	13.8
Natural Gas Liquids (billion barrels)	7.94	4.8	3.8	3.3
Natural Gas—Dry (TCF)†	193.4	149.2	124.5	116.0
Onshore (Lower 48)				
Crude Oil (billion barrels)	17.8	11.9	8.3	8.0
Natural Gas Liquids (billion barrels)	6.81	4.1	3.2	2.7
Natural Gas—Dry (TCF)†	122.2	82.0	61.0	54.0
Offshore (Lower 48)				
Crude Oil (billion barrels)	3.5	3.0	2.5	2.8
Natural Gas Liquids (billion barrels)	0.75	0.7	0.6	0.6
Natural Gas—Dry (TCF)†	37.3	33.2	29.5	28.1
Alaska				
Crude Oil (billion barrels)	7.1	5.3	3.8	3.0
Natural Gas Liquids (billion barrels)	0.38	0.01	0.01	0.01
Natural Gas—Dry (TCF)†	33.9	34.0	34.0	33.9
Memo: (in millions)				
Cumulative footage drilled from 1/1/86		767	1,549	2,508
Cumulative wells drilled from 1/1/86		.136	.328	.537

*Assumptions consistent with those used by the Energy Information Agency publication DOE/EIA-0216(85).

†TCF = trillion cubic feet.

Reconciliation of the 1985 Totals Used in Tables D-2 and D-8 With EIA's June 1986 Monthly Energy Review

NOTE: All units shown in this discussion are in trillions of BTUs per year unless otherwise noted.

Industrial

- Numbers for industrial use are for energy use only and exclude feedstocks. Industrial feedstocks are shown under "Non-Energy and Others" and when added to industrial energy use, agree with the totals for 1985 in the Monthly Energy Review (MER).
- The feedstock (non-energy) use in industry was taken from draft NEPP-VI tables that show actual use in 1985.
  - Petroleum Liquids = 3,800
  - Gas = 800
  - Coal = 100
- Industrial use of hydro and coke exports is not in the survey table.

Utility

- Hydro in the MER includes electricity imports. These are shown on page 13 to be 418. When subtracted from the hydro number (3,289) on page 33, the result is the 2,871 in the survey table. The 418 of imports are included under "other" in the survey table.
- Geothermal, included under "other" in the MER, was determined by private communication with EIA to be 199. Subtracting the 199 from the 213 of other in the MER leaves 14 of other renewables used in central station applications. The survey table shows 97 instead of 199 because EIA used a conversion factor for equivalent energy report of 21,303 BTU/kwh and the survey used 10,400 BTU/kwh.
- Adding together the 418 of imports and the 14 of other renewables gives the 432 shown as "other" in the survey table.

Renewables

- The MER does not include decentralized (dispersed) renewables in its total energy consumption. Thus, this consumption was taken from the draft NEPP-VI projections and added to the MER totals. The sectoral breakdown was taken from Table B-2 of the NEPP-VI draft report.
- The 33 of industrial hydro shown in the MER (page 29) is included in the "other" column in the survey. It is not shown separately in the hydro column.

Reconciliation

The following calculation reconciles total 1985 energy use shown in the June 1986 MER with the total consumption shown in the survey table.

Total Shown in MER	**73,959**
Add:	
Renewables in the Residential/ Commercial Sector	1,070
Renewables in the Industrial Sector (Including Hydro)	1,740
Coke Exports by Industry	13
Subtotal	76,782
Subtract:	
Discrepancy in Geothermal Number (199-97)	−102
Industrial Hydro Already in MER Total	−33
Rounding Error	+1
Total Shown on Survey Table	**76,648**

Effects of Prices on Costs of Finding, Developing, and Producing Oil and Gas

Prices vs. Rig Count

New oil price data in Figure 34 are based on the postings of a representative operator for West Texas sour 33 degree gravity crude oil. These postings are based on new oil and then upper tier prices from 1973 until the start of phased decontrol of oil prices in June 1979. Average U.S. crude oil and gas prices were calculated by first converting average gas prices to equivalent crude oil prices using a heat content equivalency of 5.7 MCF per barrel of crude oil and then volumetrically weighting average oil prices [1,2] and the converted gas prices. The Hughes rig count is the annual average of the weekly reports by the Hughes Tool Co. of the number of rotary rigs that are actually drilling when their survey is made each week.

Observed Rig Productivity

The following table shows how observed rig productivity (wells/rig) has varied over the 1970 and 1985 time period:

	API Well Completions	Hughes Rig Count	Wells Per Rig	Average Depth (Ft.)
1970	28,173	1,028	27.4	4,918
1981	89,993	3,970	22.7	4,541
1982	83,889	3,105	27.0	4,475
1983	75,738	2,232	33.9	4,180
1984	85,094	2,428	35.0	4,336
1985	72,086	1,976	36.5	4,438

Wells per rig would be expected to vary as an inverse function of well depth, with a change in average well depth causing a larger change in the ratio of wells per rig. However, as the rig count rose during the 1970s, the opposite occurred as observed rig productivity decreased from 27.4 in 1970 to 22.7 in 1981, in spite of an 8 percent reduction in the average depth per well. This could have been caused by the use of outdated equipment that normally would have been retired, using equipment for drilling tasks that were less than optimum, and the influx of inexperienced drilling crews. With the reduction in rig count after 1981, this process was reversed and rig productivity increased to 36.5 in 1985, or 61 percent over the 1981 level, while the average well depth decreased by only 2 percent from the 1981 well depth. The increase over the total time period of wells per rig from 27 to 36, or 33 percent, is a significantly larger percentage change than the 10 percent decrease in well depth from 4,918 to 4,438 feet.

The data in the above table are not completely compatible since the oil well, gas well, and dry hole completions included in the API well completion column, which are based on API's Quarterly Completed Well Reports, includes wells that are completed by other types of rigs that are not included in the Hughes rotary rig count. However, the U.S. total well-to-rig ratio in the above table tracks in a nearly parallel fashion the ratio calculated for the 17 states that predominantly use rotary rigs. Consequently, this ratio has in the past been a good surrogate for rig productivity. The recent 1986 crude oil price drop could have caused a change in mix in the type of rigs by increasing the emphasis on cheap shallow wells that can be drilled by cable tool rigs. This could cause further increases in wells per rig. This could also have affected the wells per rig count in 1983 through 1985 in all states, including those that predominantly use rotary rigs.

Irrespective of the reason for the increase in wells per rig in recent years, all factors that will cause the index to increase, namely—increased efficiency, lower well depths, and shifts to other types of drilling—will also result in lower average completed well costs.

[1]U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review, May 1986*. DOE/EIA-0035 (86105), Washington, DC, August 1986.

[2]DeGolyer and MacNaughton, *20th Century Petroleum Statistics 1985*. Dallas, TX, November 1985.

The Effect of Prices on Drilling and Reserves

Industry Expenditure Data

Table D-13 sets forth the data used to prepare Figure 37. Data in the table are actual data through 1984 and are partially estimated for 1985. Data for 1986 are completely estimated using procedures outlined in Table D-14.

The drilling and completion costs for exploration and development investments in Table D-13 are based on the Joint Association Survey of Expenditures and Revenues during 1970 through 1975 and the Joint Association Survey of Drilling Costs during 1978 through 1985. For the years 1976 and 1977, total drilling and completion costs reported in the Joint Association Survey of Drilling Costs by oil wells, gas wells, and dry holes were apportioned between exploration and development investments by using the API[3] exploratory and development well

[3]American Petroleum Institute, *Well Completions and Footage Drilled in the United States, 1970–1982*. Washington, DC, January 1985.

TABLE D-13

EXPENDITURE HISTORY OF THE PETROLEUM INDUSTRY

	1970	1971	1972	1973	1974	1975	1976	1977
Exploration Investment ($MM)								
Drilling and Completing	845	799	945	1,059	1,681	2,337	2,477	3,146
Lease Bonus	1,103	254	2,629	3,460	5,401	1,871	3,026	2,697
Operating	917	952	1,005	988	1,373	1,667	1,794	2,112
Total	2,865	2,005	4,579	5,507	8,455	5,875	7,297	7,955
Development Investment ($MM)								
Drilling and Completing	1,734	1,572	1,869	2,016	2,686	4,234	4,985	6,810
Lease Equipment	443	388	497	620	907	1,683	1,595	1,787
Improved Recovery	285	323	310	276	399	556	381	467
Development Overhead	390	387	417	297	521	790	1,417	1,168
Total	2,462	2,670	3,093	3,209	4,513	7,263	8,378	10,232
Production Expense ($MM)								
Operating Cost	2,379	2,504	2,563	3,138	3,876	4,765	5,431	6,499
Production Overhead	416	465	467	586	701	904	1,030	1,083
Total	2,795	2,969	3,030	3,724	4,576	5,670	6,461	7,582
Revenue ($MM)								
Crude Oil and Condensate	11,184	11,709	11,712	13,074	21,588	23,111	24,373	25,787
Natural Gas	3,748	4,094	4,191	4,892	6,567	8,949	11,572	15,820
Total	14,933	15,803	15,903	17,966	28,155	32,059	35,946	41,607
Royalty@ 15% ($MM)	2,240	2,370	2,386	2,695	4,223	4,809	5,392	6,241
Operating Taxes								
Property and Severance ($MM)	857	882	882	971	1,616	1,845	1,999	2,219
Property and Severance (% Rev.)	5.74	5.58	5.55	5.40	5.74	5.76	5.56	5.33
Windfall Profit Tax ($MM)	0	0	0	0	0	0	0	0
GNP Deflator								
Annual Escalation (%)	5.5	5.7	4.7	6.5	9.1	9.8	6.4	6.7
1986 Index	0.366	0.387	0.405	0.431	0.470	0.516	0.549	0.586
1986 Real Dollars ($MM)								
Exploration	7,834	5,187	11,314	12,776	17,979	11,378	13,282	13,570
Development	6,732	6,907	7,642	7,445	9,602	14,076	15,250	17,455
Subtotal	14,566	12,094	18,956	20,221	27,581	25,454	28,532	31,025
Operating Cost	7,643	7,681	7,486	8,640	9,731	10,980	11,760	12,934
Subtotal	22,209	19,774	26,442	28,861	37,312	36,434	40,292	43,959
Royalty and Property/Severance Taxes	8,468	8,414	8,073	8,504	12,417	12,887	13,453	14,432
Subtotal	30,677	28,188	34,516	37,365	49,729	49,321	53,744	58,390
Windfall Profit Tax	0	0	0	0	0	0	0	0
Total	30,677	28,188	34,516	37,365	49,729	49,321	53,744	58,390
Reinvestment Ratio (% of Net Revenue)								
Drilling and Completing	20.4	17.6	20.8	20.1	18.2	24.1	24.5	28.1
Exploration, Development, and Production	70.7	63.5	85.7	87.8	80.1	75.8	79.0	79.1

TABLE D-13 (Continued)

	1978	1979	1980	1981	1982	1983	1984	1985	1986
Exploration Investment ($MM)									
Drilling and Completing	4,246	5,075	7,224	12,185	12,427	7,171	7,102	6,692	4,315
Lease Bonus	4,489	7,801	6,927	12,460	9,834	8,068	7,653	4,563	2,303
Operating	2,521	3,388	4,858	6,599	8,035	6,590	6,931	6,723	4,706
Total	11,256	16,264	19,009	31,244	30,296	21,829	21,686	17,978	11,324
Development Investment ($MM)									
Drilling and Completing	8,815	11,004	15,576	24,480	27,001	17,934	18,104	17,005	9,275
Lease Equipment	2,479	2,526	4,260	5,374	5,896	4,371	4,744	4,412	3,971
Improved Recovery	645	584	953	1,496	1,990	1,431	1,451	1,349	1,214
Development Overhead	1,115	1,467	1,861	2,356	2,162	2,302	2,762	2,569	2,055
Total	13,054	15,581	22,650	33,706	37,049	26,038	27,061	25,355	16,515
Production Expense ($MM)									
Operating Cost	7,391	9,556	12,189	17,101	18,240	16,458	15,368	15,522	13,515
Production Overhead	1,300	1,536	2,063	2,879	3,846	3,262	4,276	4,319	3,775
Total	8,691	11,092	14,252	19,980	22,085	19,720	19,644	19,841	17,290
Revenue ($MM)									
Crude Oil and Condensate	28,602	39,449	67,922	99,408	90,038	83,048	84,110	78,871	40,056
Natural Gas	18,076	24,156	32,086	39,513	45,559	43,569	48,492	43,167	29,530
Total	46,678	63,605	100,008	138,921	135,597	126,617	132,602	122,038	69,586
Royalty @ 15% ($MM)	7,002	9,541	15,001	20,838	20,340	18,993	19,890	18,306	10,438
Operating Taxes									
Property and Severance ($MM)	2,516	3,003	5,149	7,369	7,555	6,740	7,088	6,540	3,723
Property and Severance (% Rev.)	5.39	4.72	5.15	5.30	5.57	5.32	5.35	5.35	5.35
Windfall Profit Tax ($MM)	0	0	8,648	22,605	14,797	9,425	7,833	5,000	0
GNP Deflator									
Annual Escalation (%)	7.3	8.9	9.0	9.7	6.4	3.9	3.8	3.3	3.0
1986 Index	0.629	0.685	0.747	0.819	0.871	0.905	0.940	0.971	1.000
1986 Real Dollars ($MM)									
Exploration	17,895	23,744	25,460	38,147	34,764	24,108	23,074	18,517	11,324
Development	20,754	22,747	30,337	41,153	42,514	28,757	28,793	26,095	16,515
Subtotal	38,649	46,491	55,797	79,300	77,278	52,865	51,866	44,613	27,839
Operating Cost	13,817	16,193	19,089	24,394	25,343	21,779	20,901	20,436	17,290
Subtotal	52,466	62,683	74,885	103,694	102,621	74,645	72,767	65,049	45,129
Royalty and Property/Severance Taxes	15,132	18,313	26,989	34,440	32,009	28,420	28,705	25,591	14,161
Subtotal	67,598	80,996	101,874	138,134	134,630	103,064	101,472	90,640	59,290
Windfall Profit Tax	0	0	11,583	27,599	16,979	10,409	8,334	5,150	0
Total	67,598	80,996	113,457	165,733	151,609	113,473	109,806	95,790	59,290
Reinvestment Ratio (% of Net Revenue)									
Drilling and Completing	32.9	29.8	26.8	31.1	34.2	23.3	22.4	22.8	23.0
Exploration, Development, and Production	89.5	85.0	82.0	97.3	97.0	77.8	73.9	72.0	82.6

Note: Data for 1986 and portions of 1985 are estimated.

TABLE D-14

ESTIMATED 1986 EXPENDITURES FOR PETROLEUM INDUSTRY

	Actual 1985	Estimated 1986	Percent Reduction	Comments
Production				
Crude Oil and Condensate (MMB)	3,274	3,164	3	Based on Dept. of Energy Jan. 7, 1987 estimate
Wet Marketed Natural Gas (BCF)	17,198	16,665	3	
Lease Hydrocarbons (MMBE)	6,291	6,088	3	Based on 5.7 MCF/BE
Price				
Crude Oil and Condensate ($/B)	24.090	12.660	48	Based on revising Sept. 1986 price with posting changes
Wet Marketed Natural Gas ($/MCF)	2.510	1.770	29	Used Aug. 1986 for remainder of 1986
Lease Hydrocarbons ($/BE)	19.398	11.431	41	
Revenue				
Crude Oil and Condensate ($MM)	78,871	40,056	49	
Wet Marketed Natural Gas ($MM)	43,167	29,530	32	
Lease Hydrocarbons ($MM)	122,038	69,586	43	
Activity				
Average Seismic Crew Months	378	197	48	Estimated Oct. 1986 level through rest of 1986
Exploratory Well Completions	12,523	8,967	28	Estimated fourth quarter 1986 equals third quarter 1986
OCS Lease Bonuses	1,563	203	87	Actual for 1986
Non OCS Lease Bonus	3,000	2,100	30	Estimated
Development Well Completions	59,563	36,155	39	Estimated fourth quarter 1986 equals third quarter 1986
Unit Costs				
Development Well ($MM/Well)	0.305	0.275	10	Estimated
Exploration Well ($MM/Well)	0.556	0.500	10	Estimated
Operating Expense ($/BE)	2.525	2.273	10	Estimated
Production Overhead ($/BE)	0.696	0.626	10	Estimated
Royalty (Fraction of Revenue)	0.150	0.150	0	Value in 1985
Property and Severence (Fraction of Revenue)	0.0535	0.0535	0	Value in 1985
API Development Well/JAS Development Well	1.070	1.070	0	Value in 1985
API Exploratory Well/JAS Exploratory Well	1.040	1.040	0	Value in 1985
Exploration Investment ($MM)				
Drilling	6,692	4,315	36	Activity times unit cost/API-JAS well ratio
Lease Bonus	4,563	2,303	50	Sum of OCS and non-OCS bonus activity
Operating	6,723	4,706	30	Estimated
Total	17,978	11,324	37	
Development Investment ($MM)				
Drilling	17,005	9,275	45	Activity times unit cost/API-JAS well ratio
Lease Equipment	4,412	3,971	10	Estimated
Improved Recovery	1,349	1,214	10	Estimated
Development Overhead	2,569	2,055	20	Estimated
Total	25,335	16,515	35	
Production Expense ($MM)				
Operating Cost	15,522	13,516	13	Unit cost times production
Production Overhead	4,319	3,775	13	Unit cost times production
Total	19,841	17,291	13	
Royalty and Operating Taxes ($MM)				
Royalty	18,306	10,438	43	Same as revenue reduction
Property and Severence Tax	6,540	3,723	43	Same as revenue reduction
Total	24,846	14,161	43	
Windfall Profit Tax ($MM)	5,000	0	100	
Total Expenditures ($MM)	93,000	59,291	36	

completions distributions by type of well. Development drilling and completion costs for 1976 and 1977 were determined by difference.

The remaining expenditures, except for royalty and windfall profit taxes, were based on the Joint Association Survey of Expenditures and Revenues from 1970 through 1972, the Bureau of the Census Annual Survey of Oil and Gas during 1973 through 1982, and the API Survey of Oil and Gas Expenditures for 1983 and 1984. The Bureau of the Census data had to be adjusted for a lack of complete coverage in their net company interest statistics as shown in the following table:

	Census Reported Share of U.S. Total (%)			
	1973	1977	1982	Source of Total
Net Oil and Gas Value	94.4	92.8	86.5	DOE Monthly Energy Review
Net Oil and Gas Equivalent Production	93.2	91.7	87.3	DOE Monthly Energy Review
Completed Well Costs	81.4	80.0	69.4	JAS Section I
Wells Drilled	NA	69.3	60.4	JAS Section I

The published data in the Bureau of the Census reports are segregated into nine company size strata, according to total lease revenues, making up the first 200 companies, and then a tenth size stratum containing all other companies. The first 200 companies were required to complete the survey, while a random sample according to size distribution was selected for the remaining companies. Accordingly, it has been assumed that the character of the companies not included in the Bureau of the Census survey is most closely represented by the tenth size stratum for all other companies.

Expenditure data for other companies in the tenth size stratum were compared to their reported data for the items in the above table to form a basis for grossing up to a total value for these other companies, since the amount of understatement by these items are known for the total United States. The following comparisons were used to gross up the expenditure data calculations shown in Table D-15.

Expenditures	Comparison Data
Property and Severance Taxes	Oil and Gas Value
Operating Costs	Oil and Gas Production
Production Overhead	Oil and Gas Production
Development Overhead	Completed Wells Costs (Oil, Gas, & Dry)
Lease Equipment	Oil & Gas Completed Well Costs
Improved Recovery	Oil and Gas Value
Lease Bonus	Oil and Gas Value
Exploration Operating	Oil and Gas Value

Since the Bureau of the Census did not report improved recovery expenditures during 1973 through 1975, the improved recovery expenditures reported by the Joint Association Survey of Expenditures and Revenues for 1973 through 1975 were used. Accordingly, the development overhead expenditures in Table D-15 had to be reduced by these expenditures as shown in the following table:

Year	Bureau of Census Development Overhead ($MM)	Joint Assn. Survey Improved Recovery ($MM)	Revised Development Overhead ($MM)
1973	573	276	297
1974	920	399	521
1975	1,346	556	790

Costs during 1985 for the items in Table D-15, excluding exploration operating, lease bonus, and property and severance taxes, were estimated by adjusting 1984 costs by DOE[4] estimates of the variations in costs between 1984 and 1985 for lease equipment and operating cost. Property and severance taxes were varied between 1984 and 1985 in accordance with the variation in oil and gas revenue while exploration operating expense was assumed to be reduced by 3 percent.

The data on lease bonus expenditures were modified to conform with OCS leasing expenditures, as shown in Table D-16. The total expenditure amounts are listed under column 4 in this table. These expenditures are as reported by the Joint Association Surveys during 1959–72; they are based upon the adjusted annual surveys of oil and gas by the Bureau of the Census in Table D-15 during 1973–82; and they are from the American Petroleum Institute's Survey on Oil and Gas Expenditures for 1983 and 1984. The OCS lease bonus expenditure amounts are listed under column 2 with the December portion of same listed under column 3. The source of the OCS data is the Minerals Management Service of the U.S. Department of the Interior. Columns 5 and 6 pertain to the non-OCS lease bonus expenditures.

The data gathering procedures do not differentiate between cash and accrual systems of accounting. OCS bonus payments are not due until 30 days after the sale date. Accordingly, the December OCS expenditures under column 3 can be included in either the current or the

[4]U.S. Department of Energy, *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations 1985 by Energy Information Administration.* DOE/EIA-0185 (85), Washington, DC, April 7, 1986.

TABLE D-15

ADJUSTMENT OF BUREAU OF CENSUS DATA — 1973–1982
(Millions of Dollar)

	Property and Severance Taxes	Operating Costs	Production Overhead	Development Overhead*	Lease Equipment	Improved Recovery†	Lease Bonus	Exploration Operating
Reported by Bureau of Census								
1973	925	2,787	497	517	572	0	3,552	935
1974	1,534	3,499	601	850	824	0	5,774	1,296
1975	1,746	4,311	769	1,265	1,500	0	1,615	1,555
1976	1,898	4,877	866	1,334	1,487	378	3,024	1,671
1977	2,099	5,714	905	1,048	1,608	461	2,580	1,962
1978	2,379	6,546	1,070	908	2,175	639	2,885	2,360
1979	2,750	7,834	1,181	1,146	2,146	528	7,037	2,939
1980	4,565	10,191	1,710	1,457	3,573	941	7,899	4,225
1981	6,639	14,545	2,245	1,717	4,760	1,458	11,188	5,906
1982	6,609	15,515	3,048	1,691	5,135	1,944	8,163	6,712
Adjusted Data								
1973	971	3,138	586	573	620	0	3,727	988
1974	1,616	3,875	701	920	907	0	6,041	1,373
1975	1,845	4,765	904	1,346	1,683	0	1,730	1,667
1976	1,999	5,431	1,030	1,417	1,595	381	3,167	1,794
1977	2,219	6,499	1,083	1,168	1,787	467	2,697	2,112
1978	2,516	7,391	1,300	1,115	2,479	645	3,071	2,521
1979	3,003	9,556	1,536	1,467	2,526	584	7,493	3,388
1980	5,149	12,189	2,063	1,861	4,260	953	8,653	4,858
1981	7,369	17,101	2,879	2,356	5,374	1,496	12,373	6,599
1982	7,555	18,240	3,846	2,161	5,896	1,990	9,922	8,035

*Includes other capital.

†Included in development overhead during 1973 through 1975.

TABLE D-16

LEASE BONUS EXPENDITURES
(Millions of Dollars)

Year	OCS Lease Bonus Total	OCS Lease Bonus December	Total Lease Bonus	U.S. Non-OCS Lease Bonus Unadjusted	U.S. Non-OCS Lease Bonus Adjusted	Revised U.S. Total Lease Bonus
1970	945	847	714	(231)	158	1,103
1971	96		642	546	158	254
1972	2,251	1,666	1,722	(529)	378	2,629
1973	3,082	1,491	3,727	645	378	3,460
1974	5,023		6,041	1,018	378	5,401
1975	1,088	417	1,730	642	783	1,871
1976	2,243		3,167	924	783	3,026
1977	1,569		2,697	1,128	1,128	2,697
1978	1,767	872	3,071	1,304	2,722	4,489
1979	5,079	1,305	7,493	2,414	2,722	7,801
1980	4,205		8,653	4,448	2,722	6,927
1981	6,613	322	12,373	5,760	5,847	12,460
1982	3,987		9,922	5,935	5,847	9,834
1983	5,749		8,068	2,319	2,319	8,068
1984	3,928		7,653	3,725	3,725	7,653
Totals	**47,625**		**77,673**	**30,048**	**30,048**	**77,673**
1985	1,563	124			3,000E	4,563

following year's total under column 4. Therefore, the non-OCS bonus amounts listed under column 5 are obtained by subtracting OCS sale amounts from total U.S. expenditure amounts. These numbers are obviously in error in a couple of years where negative numbers are calculated and could be in error during any year having a December lease sale. For those groupings of years containing significant December OCS sales amounts, the non-OCS expenditures have been averaged and listed in column 6, yielding a revised schedule of lease bonus expenditures in the last column.

OCS lease sale expenditures are known for 1985 and are tabulated on the bottom of the table. Non-OCS lease bonus expenditures were decreased by approximately 20 percent to obtain estimated total lease bonus expenditures for 1985.

Crude oil and natural gas royalty data, on an industry basis, are not available. However, it was possible to work up in most years the gross and net (after deducting royalty) crude oil production volumes for large, medium, and small companies, which generally accounted for about two-thirds of the total U.S. production (see Table D-13). The net and gross crude oil volume factors appeared generally steady at about 0.85 without any strong tendency for variation with company size or time. It has been assumed that a 15 percent royalty rate can also be applied to natural gas volumes and further be applicable to revenue amounts based on oil and gas production volumes and prices.[5,6]

Windfall profit tax payments have been reported by quarter by the Internal Revenue Service from the commencement of the tax in 1980 through the third quarter of 1985. The payments listed in Table D-13 exclude the royalty owners' share of the tax payments. Values for 1985 were obtained by extrapolating the trend observed during the first three quarters of 1985.

[5]U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review, September 1986*. DOE/EIA-0035 (86105), Washington, DC, December 1986.

[6]January 10, 1987, letter from Dr. H. A. Merklein, Department of Energy, to Dr. E. H. Murphy, American Petroleum Institute.

Reserves Discussion

The division between reserve growth and new field discoveries of reserve additions of crude oil and natural gas in the United States from 1970 to 1985 was calculated as follows. First, the gross reserve additions for oil and gas from 1970 to 1983 were determined for each state or district and for the nation as a whole. (Gross reserve additions in any one year are the sum of net adjustments, net revisions, extensions, new pool discoveries, and new field discoveries.) The data used to determine gross reserve additions were the annual reports of the API/AGA on reserves of crude oil, natural gas, and natural gas liquids in the United States; the annual reports of EIA on U.S. crude oil, natural gas, and natural gas liquids reserves; and R. Nehring, *Linking U.S. Oil and Gas Reserve Estimates*, The Rand Corporation, N-2049-DOE, September 1983 (this report linked the two sets of reserve estimates for crude oil and natural gas by state or district). The estimates of gross reserve additions were adjusted for the large net negative revisions in natural gas reserves in the Louisiana and Texas Gulf Coast region during this period (45.3 TCF total). Excluding these negative revisions, gross reserve additions of natural gas from 1970 to 1985 were thus calculated at 240.5 TCF.

Using the API/AGA estimates of ultimate recovery by year of discovery, the latest estimate in the Significant Oil and Gas Fields data base of known recovery of crude oil and natural gas for all significant fields (one million barrels or more) discovered since 1970, and estimates of oil and gas discovered in fields that were not significant, the amount added to reserves from new discoveries was determined in each state or district. For the United States as a whole, this added up to 11.4 billion barrels of crude oil and 144.0 TCF of natural gas. Reserve growth in older fields was then calculated as a residual, the amount added from new discoveries being subtracted from gross reserve additions. Reserve additions from reserve growth were thus determined to be 23.3 billion barrels of crude oil and 96.5 TCF of natural gas for the 1970–85 period. As a result, approximately 67 percent (23.3 ÷ 34.7) of crude oil and 40 percent (96.5 ÷ 240.5) of natural gas has come from reserve growth in fields discovered prior to 1970.

NPC Survey Reserve-to-Production Ratio Analysis

The projected decline in reserves does not result in a proportional decline in production (see table below). Both oil and gas production are projected to decrease at a slower rate than reserves. As a result, the ratio of reserves-to-production (the R/P ratio) declines during the next 15 years from 9.2 to 7.9 (lower price) and 6.9 (upper price) for crude oil and condensate.

PROJECTED DOMESTIC RESERVE-TO-PRODUCTION RATIOS — 1985-2000

	Lower Price Trend		Upper Price Trend	
Crude Oil and Condensate				
1985	9.2		9.2	
1990	8.4		7.9	
1995	8.0		7.4	
2000	7.9		6.9	
Natural Gas, Wet*				
1985	11.8	(10.2)	11.8	(10.2)
1990	10.1	(8.3)	10.3	(8.7)
1995	10.3	(8.1)	10.6	(8.7)
2000	9.9	(7.6)	10.8	(8.7)

*Data for 48 contiguous states are in parentheses.

For natural gas, the R/P ratio for the entire United States declines from 11.8 to 9.9 (lower price) and 10.8 (upper price). For the contiguous 48 states—the area from which domestic gas supply will essentially be drawn—the R/P ratio for natural gas declines from 10.2 to 7.6 (lower price) and to 8.7 (upper price).

The crude oil and condensate R/P ratios are lower in the upper price trend than in the lower price trend because respondents apparently projected that the higher prices would permit the drilling of more marginal wells and more infill wells to boost production. These wells would generally be expected to have lower ultimate recoveries and lower R/P ratios than the average well. This more than offsets the impact of a higher activity level that increases the relative number of initial well complétions that are produced for only a portion of the year, thereby increasing the R/P ratio. Although the same factors would also affect gas well drilling, the respondents probably also included the drilling of more deep gas wells and unconventional gas wells in the upper price trend. These wells would have higher R/P ratios than the average gas well and could in conjunction with the increased activity levels be the reason the R/P ratio is higher for the upper price trend than for the lower price trend for natural gas. Since the R/P ratio is smaller in the lower price trend for natural gas, reserves decline at a faster rate than in the upper price trend and production remains relatively higher. Lower activity levels in the lower price trend arise from the reduced incentive to explore and develop.

Appendix E

IPAA/SIPES Drilling Survey

The Independent Petroleum Association of America (IPAA) and the Society of Independent Professional Earth Scientists (SIPES) surveyed their memberships with the intent of determining how the recent oil price decline has impacted the near-term outlook for drilling. The respondents were asked to estimate their participation in wells from 1986 to 1990 based on three alternate price levels for oil and gas: $13 per barrel and $1.30 per thousand cubic feet respectively; $20 per barrel and $2.40 per thousand cubic feet; and $27 per barrel and $3.50 per thousand cubic feet. The low and middle price assumptions here approximate the lower and upper price trends of the NPC Oil & Gas Outlook Survey. There were 1,023 usable responses out of an estimated 7,000 potential respondents. The responses covered participation in 18,102 wells in 1985, for an average of 17.7 well participations and $2.4 million investment per respondent.

The data is best summarized by using 1985 as a base year and expressing the number of wells in which respondents would participate as a percentage of that base.

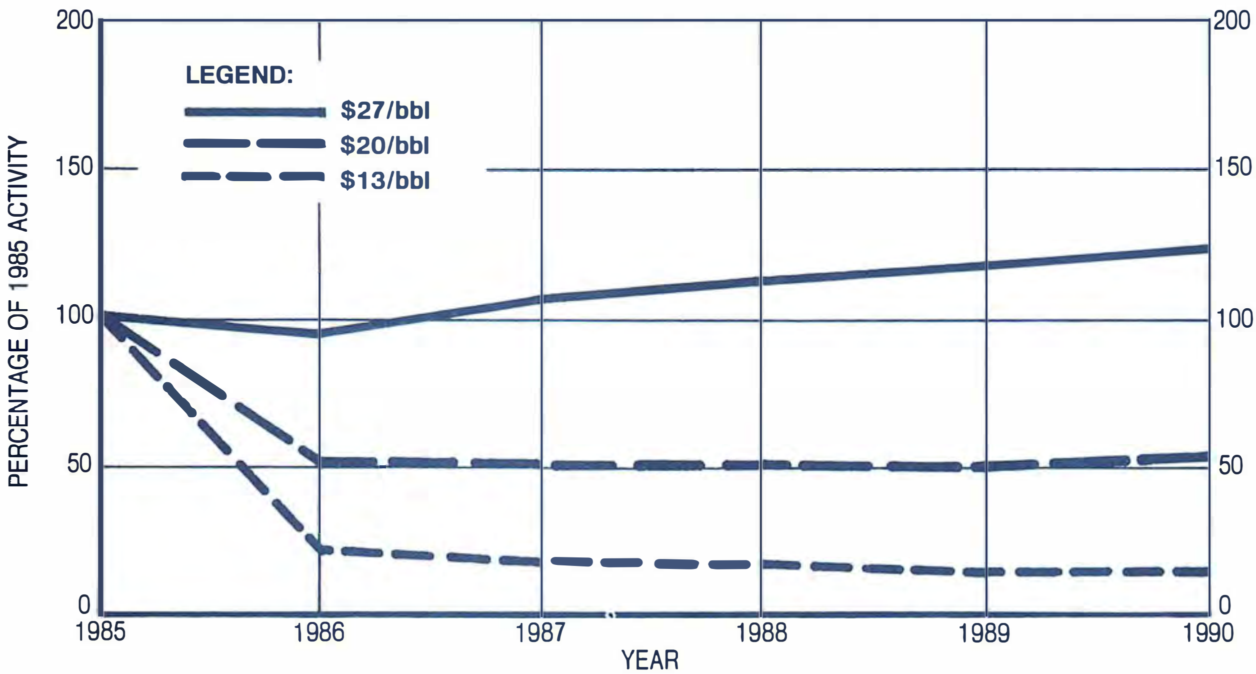

Figure E-1. Activity Change for All Respondents.

PERCENTAGE CHANGE IN RESPONDENT ACTIVITY

at	Percentage of 1985 Base 1985	1986	1987	1988	1989	1990
$13/$1.30	100	21.6	18.3	15.6	14.0	14.7
$20/$2.40	100	50.0	51.2	51.3	50.6	52.5
$27/$3.50	100	95.3	106.8	112.8	116.8	124.0

Clearly, a substantial reduction in drilling activity is projected by the respondents for the low and middle price assumptions. These drilling trends largely confirm the level of domestic activity implied by the NPC Oil & Gas Outlook Survey. The high price assumption in this IPAA/SIPES Survey represents approximately the oil price before the recent decline, and respondents indicate a decline in 1986, followed by moderate growth in drilling thereafter.

A breakdown of survey results was made by operating size of respondent, by comparing the estimates of respondents above and below the average of 17 wells per respondent in 1985. Those who participated in less than 17 wells in 1985 represented over 70 percent of the respondents. Of significance was that these smaller operators showed a more extreme response in estimated well participation in both high and low price assumptions.

PERCENTAGE CHANGE IN RESPONDENT ACTIVITY
FEWER THAN 17 WELLS

at	Percentage of 1985 Base 1985	1986	1987	1988	1989	1990
$13/$1.30	100.0	19.2	14.0	12.3	11.5	11.8
$20/$2.40	100.0	61.6	64.8	67.0	68.4	69.3
$27/$3.50	100.0	124.0	143.8	154.0	162.9	171.1

PERCENTAGE CHANGE IN RESPONDENT ACTIVITY
MORE THAN 17 WELLS

at	Percentage of 1985 Base 1985	1986	1987	1988	1989	1990
$13/$1.30	100.0	22.4	19.7	16.7	14.8	15.7
$20/$2.40	100.0	46.0	46.5	45.9	44.5	46.8
$27/$3.50	100.0	85.5	94.1	98.7	101.0	107.8

The above tends to confirm the empirical observation that the smaller operators respond faster and to a greater degree than the larger entities.

NATIONAL PETROLEUM COUNCIL DRILLING SURVEY

Total wells participated in during 1985 ____________________

Total investment in these wells (approximate) ____________________

Assuming present law tax treatment, availability of good quality prospects and 1985 drilling costs, plus/minus inflation (if any), we would anticipate participating in the following number of wells if the average prices were:

	$13/BBL $1.30/MCF	$20/BBL $2.40/MCF	$27/BBL $3.50/MCF
1986	________	________	________
1987	________	________	________
1988	________	________	________
1989	________	________	________
1990	________	________	________

Please return by June 16, 1986 to: John H. Guy, IV, Deputy Executive Director
National Petroleum Council
1625 K Street, N.W., Washington, D.C. 20006

APPENDIX F

ACRONYMS AND ABBREVIATIONS

ANWR—Arctic National Wildlife Refuge

API—American Petroleum Institute

BOE—barrel of oil equivalent

BTU—British thermal units

CAFE—Corporate Average Fuel Economy

DOE—U.S. Department of Energy

DRI—Data Resources, Inc.

E&D—exploration and development

EIA—Energy Information Administration

EOR—enhanced oil recovery

EPA—Environmental Protection Agency

EPCA—Energy Policy and Conservation Act

FEA—Federal Energy Administration

FEO—Federal Energy Office

FERC—Federal Energy Regulatory Commission

FPC—Federal Power Commission

GDP—gross domestic product

GNP—gross national product

IPAA—Independent Petroleum Association of America

LNG—liquefied natural gas

MB/D—thousand barrels per day

MCF—thousand cubic feet

MMB/D—million barrels per day

MW—megawatts

NGA—Natural Gas Act

NGPA—Natural Gas Policy Act

NPC—National Petroleum Council

OCS—Outer Continental Shelf

OECD—Organization for Economic Cooperation and Development

OPEC—Organization of Petroleum Exporting Countries

SIPES—Society of Independent Professional Earth Scientists

SMPs—special marketing programs

SPE—Society of Petroleum Engineers

SPR—Strategic Petroleum Reserve

TCF—trillion cubic feet

USGS—United States Geological Survey

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