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With Projections to 1995

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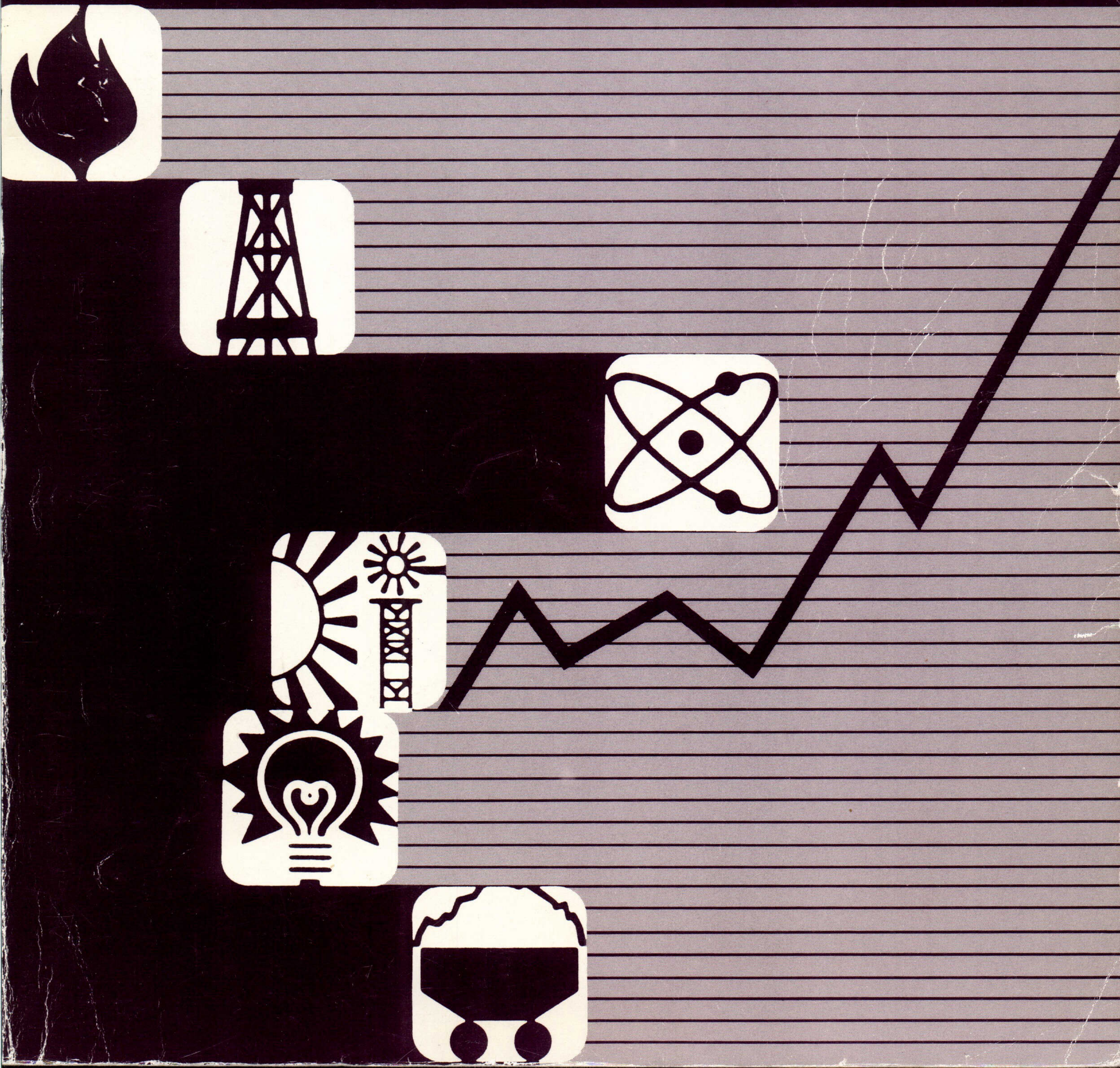

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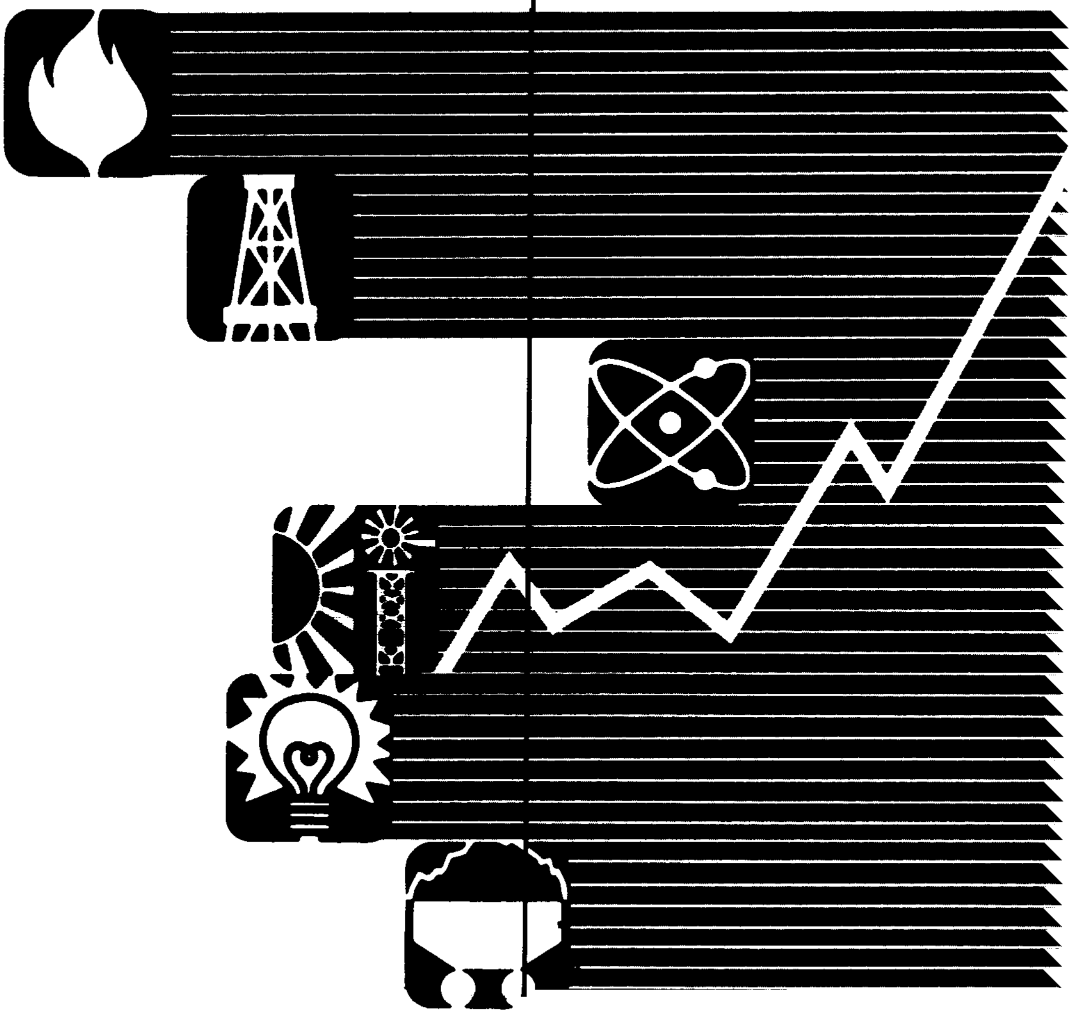

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Preface

Since 1976 the Energy Information Administration (EIA) and its predecessor agencies have provided projections of energy production, supplies, and prices. This report is the second Annual Energy Outlook. In most cases, previous projections were published in Volume 3 of the Annual Report to Congress. (The Annual Report for 1983, describing the activities of EIA, was published in March of this year.)

This report provides yearly projections through 1995 of the consumption and supply of energy by fuel and end use sector for use by members of Congress, the Administration, and the public. (Projections for the short term are provided in EIA's quarterly Short-Term Energy Outlook, issued each February, May, August, and November. Each issue of this publication presents updated energy production, consumption, and price projections for five or six calendar quarters.) The Annual Energy Outlook, 1983, like its predecessor, is specifically directed at the analysis of the issues, technologies, policies, and economic events that affect the Nation's energy future.

The report was produced by the Energy Analysis and Forecasting Division in the Office of Energy Markets and End Use in cooperation with the other Offices of the Energy Information Administration. This year's projections were produced using the Intermediate Future Forecasting System (IFFS) together with the Gas Analysis Modeling System (GAMS).

The analysis of petroleum and natural gas was provided by the Office of Oil and Gas. The coal, nuclear, and electric utility analysis was provided by the Analysis and Forecasting branches of the Coal, Nuclear, Electric and Alternate Fuels Office.

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Executive Summary

Overview

This is the second Annual Energy Outlook and the eighth annual energy forecast published by the Energy Information Administration and its predecessor agencies since the oil embargo of 1973-74. Ten years after the interruption of world oil supplies that brought energy to the forefront of national attention, the energy outlook is different from that the decade just past and different from the outlook just 1 year ago.

In an increasingly competitive world energy market, dramatic moves by energy-producing countries to increase the price of oil are becoming increasingly unlikely. Despite 3 years of conflict by two countries that control roughly 15 percent of OPEC production capacity, the current outlook is for slight declines in the average world price for oil for the next 2 to 3 years, and then for a gradual rise in the real price of oil to about the levels of 1980 by the early 1990's. This is essentially last year's oil forecast with the price rise delayed by 2 to 3 years. Higher growth in oil demand or slower expansion of oil production capacity could produce higher oil prices, while greater conservation and increased competition among oil producers could result in lower prices.

This more optimistic outlook for oil prices has been adopted because the expected recovery of world economic growth has not been sufficient to offset other factors that hold down demand for oil. Both Europe and the United States have had the blessing of two mixed but essentially warm winters that moderated usual seasonal peaks in oil demand and kept markets slack. Moreover, conservation continues to moderate the total demand for energy, particularly petroleum, as efficiency of use continues to increase in response to the past 10 years of higher energy prices.

The progress of conservation over the past 2 to 3 years has been greater than projected by energy forecasters in the 1970's. The unexpectedly slow recovery of petroleum, gas, and electricity demand over the last year suggests that the full impact of the past 10 years of higher prices is not completely understood. This forecast has been revised to incorporate the latest short-term trends in aggregate energy use, but future demand projections could be even lower when more detailed sectoral data for the current period become available. Only this will show the details of how the economy recovers from the recession.

It now appears far less likely than it did last year that the gas industry will be faced with a massive loss of market in the 1980's. Last year, it appeared that inflexible contracts for natural gas supplies would continue to drive prices up despite weak demand. For a time, rapidly rising prices of natural gas relative to oil did appear to cause gas consumers to begin switching out of gas into oil. This year's projection, in contrast, reflects the progressive adaptation of the gas industry to new market conditions. Significant revisions have been made in the natural gas price structure to meet the competition from lower fuel oil prices. In particular, it appears that the natural gas tariff structure is being modified to retain large industrial and utility customers that are readily able to switch fuels. Thus, this year's wellhead gas price forecast shows only very slight increases until the price of fuel oil increases in the late 1980's. The rapid increase in gas prices upon partial decontrol in 1985 is no longer expected.

Finally, it appears that the trend to electrification will continue, although only at about half the rate of the early 1970's. After a rapid projected recovery in 1984, the demand for electricity is forecast to grow about 0.4 percent per year faster than the economy for the next decade. An increasingly automated economy, apparently less dominated by its foundry sectors, appears to be responding positively to the much slower growth in electricity prices. Progressive expansion of the U.S. economy in the South and West, where electricity is relatively more important than in other regions, is also a large factor. The completion of coal and nuclear generation capacity currently under construction is projected to provide most of the increased generation requirements. The consequent reduction in average fuel costs due to reduction of the share of oil and gas in electricity generation is projected largely to compensate for increases in the utility rate base due to the new capacity additions. Thus, electricity price increases could be moderate into the 1990's, depending upon the growth in demand. Higher demand reduces capital costs per kilowatt-hour sold, which make up about 30 to 40 percent of the electricity price.

Two key assumptions drive energy forecasts: the assumed price of world crude oil supplies, and the rate of economic growth and its underlying indicators. The next sections of this summary itemize the assumptions and then identify the key points in this volume that are explained in detail in the nine chapters that follow. The Middle, Low, and High world oil price forecasts are tabulated in Appendixes A, B, and C, respectively.

Major Forecast Assumptions

As is usual in this series of *Outlooks*, no attempt is made to forecast legislative changes. It is assumed that there will be no major changes in Federal leasing policies for energy-producing lands and offshore areas apart from termination of the current leasing moratoria on federal lands. The movement toward decontrol of natural gas prices is assumed to proceed as specified in the Natural Gas Policy Act of 1978. Current environmental regulations are assumed to remain in place. The regulation of nuclear power and current plans for completing the construction of nuclear electric plants are also assumed to remain unchanged.

Petroleum Prices. While OPEC's ability to maintain world oil prices has weakened in the last few years, the midprice case assumed in this report projects a decline in the real world oil price only through 1986. Continued relatively slow economic growth and the rise in non-OPEC oil production and exports, particularly by Mexico and the United Kingdom, are expected to maintain downward pressure on oil prices over the next few years. An initially slow, but persistent rise in oil prices beyond 1986 results from an increasing demand for oil--particularly for oil from OPEC countries--which reduces current levels of surplus production capacity.

Three alternative world oil price assumptions have been used as the basis for the principal forecasts in this report, as shown in Table ES1. In the midprice assumption, the world oil price (in 1983 dollars) falls to a minimum of $26 in 1986, then rises to $37 per barrel in 1990 and $50 per barrel in 1995. No major disruptions are assumed in these scenarios, although the potential consequences of an abrupt rise in world oil prices are examined in Chapters 2 and 7. The high and low price cases reflect futures in which increases in world oil production are lower and higher, respectively, than in the midprice case. In the high price case, real oil prices rise throughout the forecast period. In the low case, prices fall further and rise later and more slowly than in the midprice case, returning to 1982 levels only in the middle 1990's.

Table ES1. World Oil Price: History and Assumptions
(1983 Dollars per Barrel)

Price	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Middle	35	29	28	27	26	27	31	34	37	39	42	45	48	50
Low	35	29	24	22	22	22	24	27	29	32	34	35	36	37
High	35	29	30	31	31	34	38	42	46	51	54	57	61	66

There remains significant uncertainty in the ability to predict world oil prices in the 1990's and beyond. The foundation of this uncertainty rests on two principal questions:

1. How will the effect of competition at all levels of the world energy producing system affect the ability of OPEC to set arbitrary prices?

2. How will consumers respond to the assumed resumption of increases in the real price of oil? The ability of consumers to effect surprising amounts of conservation has already been demonstrated.

The assumptions shown in Table ES1 make no special allowance for increased competition, or for an increased level of conservation other than that already demonstrated and should, therefore, be viewed in that light.

Macroeconomic Assumptions. Following a recovery from the recession of the early 1980's, U.S. economic growth is assumed to slow as the work force grows more slowly and energy price pressures rise. The principal macroeconomic assumptions for the midprice case are summarized in Table ES2. Since economic growth can be depressed by higher prices for imported oil, the income levels for the high price and low price cases are lower and higher, respectively, than in the midprice assumptions. This effect is discussed in Chapter 7.

Table ES2. Assumed Historical and Projected Growth Rates for the Principal Economic Aggregates and Population, Middle World Oil Price Case

Economic Aggregate	1983 to 1985	1983 to 1990	1983 to 1995	1985-90	1990-95
	(average annual percentage rate)				
Real Gross National Product	4.0	3.3	2.9	3.1	2.2
Real Disposable Personal Income	4.1	2.9	2.6	2.5	2.0
GNP Price Deflator	4.5	5.5	6.0	5.8	6.7
Population	0.92	0.92	0.87	0.92	0.80

Note: Assumptions are from the midprice case, Table 14 in Chapter 3.

Energy Consumption

Overview. The long-term trend toward energy conservation, as indicated by the declining ratio of Btu consumed to gross national product (GNP) (measured in constant dollars), is projected to continue through the forecast period. Even in the low-price case, energy prices are significantly higher than before 1979 so that the long-term incentive to continue to conserve energy--particularly through the installation of more energy-efficient capital equipment--is expected to persist. Further incentives for conservation are expected when oil and gas prices rise in the late 1980's.

Because of its efficiency in end-use applications and the projected improvement in the price of electricity relative to other energy forms, electricity's share of end-use energy consumption is forecast to continue to rise. More extensive and intensive use in homes, businesses, and industry causes projected electricity consumption to rise nearly three times faster than total end-use energy consumption through the forecast period.

End-Use Energy Consumption. As shown in Table ES3, end-use energy consumption in the midprice case for the period 1983-95 is projected to grow fastest in the commercial sector (2.1 percent per year) and industrial sector (1.6 percent per year) compared to a 0.7 percent rate in transportation and 0.3 percent per year in the residential sector. Higher or lower world oil prices would modify these growth rates with the transportation sector being most affected as shown in Table ES3.

Table ES3. Range of End-Use Energy Consumption and Growth Rates for the Middle, Low, and High World Oil Price Cases (Quadrillion Btu)

Sector	1973	1978	1983	1985	1990	1995
Residential						
Middle	9.9	10.0	8.7	8.9	9.2	9.1
Low/High	_	_	_	9.0/8.9	9.4/9.0	9.4/8.8
Commercial						
Middle	5.9	6.0	5.6	6.4	7.1	7.2
Low/High	_	_	_	6.5/6.4	7.2/6.9	7.5/6.9
Industrial						
Middle	25.9	24.6	19.6	21.3	22.9	23.7
Low/High	_	_	_	21.3/21.3	23.2/22.6	24.4/23.1
Transportation						
Middle	18.6	20.6	19.0	19.8	20.5	20.7
Low/High	_	_	_	19.9/19.6	21.3/19.5	22.2/19.2
Total End-Use Energy Consumption						
Middle	60.2	61.2	52.8	56.4	59.6	60.7
Low/High	_	_	_	56.7/56.2	61.1/58.0	63.5/58.0

Growth Rates (Percent)

	to 1983		from 1983 to			
	1973	1978	1990	1995	1985–1990	1990–1995
Residential						
Middle	-1.3	-2.7	0.8	0.3	0.6	-.3
Low/High	_	_	1.1/0.5	0.7/0.0	1.0/0.3	0.0/-0.6
Commercial						
Middle	-0.1	-1.5	3.4	2.1	1.9	0.4
Low/High	_	_	3.7/3.1	2.5/1.8	2.2/1.5	0.8/0.0
Industrial						
Middle	-2.7	-4.5	2.3	1.6	1.4	0.7
Low/High	_	_	2.4/2.0	1.8/1.4	1.7/1.2	1.0/0.4
Transportation						
Middle	0.2	-1.6	1.1	0.7	0.7	0.2
Low/High	_	_	1.7/0.4	1.3/0.1	1.3/-0.1	0.8/-0.3
Total End-Use Consumption						
Middle	-1.3	-2.9	1.7	1.2	1.0	0.4
Low/High	_	_	2.1/1.3	1.5/0.8	1.5/0.6	0.8/0.0

Source: Table 4 for cases in Appendixes A, B, and C.
Note: "Low/High" refers to range of values from the low and high cases, respectively.
_ = not applicable.

Residential energy use is determined primarily by household incomes, population characteristics, and energy prices. Although both income and population growth are projected to slow over the forecast period, the number of occupied housing units is forecast to rise at an annual rate of 1.7 percent, almost twice as fast as the U.S. population. Continued energy price increases (Table ES4), smaller housing units, conservation measures, the movement of population to warmer regions, and increasingly efficient use of electricity are projected to cause residential end-use energy consumption per household to decline at a 1.4-percent annual rate. As a result, residential energy use, which is primarily for space heating, water heating, and air conditioning, is forecast to grow at only 0.3 percent per year. Alternative price paths affect energy growth in the residential sector only modestly.

Because of the robust growth of services in the economy, energy use is projected to rise most rapidly in the commercial sector. In 1983, about three-fifths of commercial energy use was in office and retail/wholesale buildings; natural gas and electricity accounted for over four-fifths of commercial energy use. Energy use per square foot of commercial building space is forecast to continue to decline under the influences of rising energy prices and the resulting conservation measures, together with the more rapid growth of commerce in warmer regions. Total commercial natural gas consumption is forecast to rise somewhat over the forecast period, while electricity consumption reflects most of the growth. Regional differences in projected commercial floorspace growth explain much of the increased reliance on electricity: building floorspace in the South and West census regions, which have relied heavily on electricity in the past, is projected to grow about twice as fast as building floorspace in the North and East census regions.

Over 60 percent of U.S. petroleum consumption and almost 36 percent of total end-use energy consumption occurred within the transportation sector in 1983. Although the energy efficiency of automobiles, trucks, and aircraft is projected to continue to improve, recent declines in the real prices of transportation fuels, rising affluence, and changing tastes of the new-car-buying population are shifting the mix of new vehicles away from the recent conception of a small car America. As a result, the trend toward higher average automotive fleet efficiency has slackened somewhat. Partly because of improved efficiency, motor gasoline consumption is projected to decline by over 9 percent from 1983 to 1995 despite a projected 59-percent increase in automobile vehicle-miles traveled. In addition, diesel fuel oil is projected to make significant inroads into the expanding intermediate-weight truck market. The slow growth (0.7 percent per year) that is forecast for transportation energy use accounts for much of the diminished role that petroleum is projected to play in future U.S. energy use. Transportation oil consumption is projected to be most sensitive to oil prices because higher prices influence both the growth rate of vehicle-miles travelled and the efficiency of cars chosen by consumers. With high oil prices, growth in transportation oil consumption is negligible through the forecast period. Low oil prices nearly double the rate of growth compared to the midprice case in transportation oil consumption in the 1985-90 period, and maintain significant growth out to 1995.

The industrial sector is the major consumer of energy, accounting for an estimated 37 percent of the U.S. end-use energy consumption in 1983. Following several years of weakness in this sector, total industrial energy consumption, under the midprice projection, is forecast to grow by 2.3 percent per year from 1983 to 1990 and then by 0.7 percent per year from 1990 to 1995, somewhat slower than overall economic growth. Industrial energy consumption, including the use of natural gas and electricity, is projected to rise moderately in response to economic activity that is stimulated, in part, by lower oil prices.

As demonstrated in the past 3 years, the overall industrial fuel mix is very sensitive to short-term shifts in the growth and structure of the economy. Industrial fuel shares are projected to shift significantly over the forecast period, with electricity increasing from less than 14 percent of industrial energy use in 1983 to almost 18 percent in 1995. The industrial natural gas consumption

Table ES4. Selected Energy Prices, World Oil Midprice Case
(1983 Dollars per Million Btu)

Sector/Energy Source	1973	1978	1983	1985	1990	1995
Residential						
Natural Gas	2.60	3.62	5.80	6.01	7.38	10.67
Heating Oil	3.37	5.13	7.88	7.30	9.29	12.12
Electricity	14.28	17.01	19.02	19.32	19.51	20.12
Average All Sources	5.41	7.20	10.03	10.20	11.67	14.38
Commercial						
Natural Gas	1.89	3.16	5.42	5.55	6.83	10.04
Heating Oil	2.78	4.53	6.42	5.84	7.81	10.62
Electricity	13.51	16.83	19.20	19.55	19.81	20.59
Average All Sources	5.03	7.51	10.73	10.75	12.02	14.53
Industrial						
Natural Gas	0.99	2.41	4.18	4.33	5.56	8.64
Residual Fuel Oil	1.63	3.01	4.12	3.78	5.18	7.08
Electricity	7.05	10.94	16.20	16.46	16.62	17.15
Average All Sources	2.02	4.07	6.18	6.03	7.34	9.60
Transportation						
Motor Gasoline	6.34	7.54	9.79	9.03	11.31	14.37
Distillate	3.23	4.76	8.67	8.08	10.07	12.88
Average All Sources	5.09	6.50	8.93	8.22	10.32	13.26
Electric Utility Inputs						
Natural Gas	0.76	2.04	3.37	3.44	4.49	7.05
Residual Fuel Oil	1.59	3.05	4.28	3.97	5.44	7.37
Steam Coal	0.94	1.85	1.72	1.82	1.90	2.13
Average, for Fossil Fuels	1.05	2.17	2.24	2.25	2.58	3.41
Average All Sectors	3.20	4.91	6.72	6.51	7.68	9.50

Source: Historical data to 1980 from The State Energy Price System. Forecasts shown for 1983-95 are from the midprice case, Table 5 in Appendix A.

share is forecast to decline, while the share of oil in industrial consumption rises and industrial coal consumption ends its long-term decline and increases its share of industrial energy use.

Although the industrial sector has a relatively wide scope for substituting between alternative fuels (through shifts in the mix of production, process changes, and investment in new equipment), total energy use per unit of industrial output appears to be relatively insensitive to energy prices in the short term.

Energy price changes have a noticeable lagged effect on the efficiency of industrial energy use. This sector's embedded capital appears to turn over at about 10 percent per year and, as new stock is added, energy use drops by about 2 percent for every 10-percent increase in prices. The trend toward the production of less energy-intensive products is expected to continue to reduce the energy use per unit of total industrial output. Higher or lower world oil prices affect the manufacturing sector principally through the changes in output level of the economy, and the direct effect of world oil price on oil consumption in this sector appears to be small.

Primary Energy Sources

Overview

Compared to many countries, the United States is well-endowed with energy resources. The major source of energy for domestic consumption in 1983 was petroleum, which provided 43 percent of domestic energy consumption. Largely because oil and gas consumption in 1983 was reduced by the recession and a warm winter, only 28 percent of the petroleum consumed was accounted for by net imports. Natural gas provided 25 percent of U.S. energy consumption; only 6 percent of this was imported. The United States is the world's largest producer of coal, which provided 22 percent of domestic energy consumption in 1983.

While petroleum is projected to remain the principal source of energy consumed in the United States throughout the forecast period, coal is expected to become the major domestically produced energy form in this decade. Domestic oil and natural gas production are projected to remain relatively stable through the 1980's, then decline slowly in the 1990's.

Petroleum

The Nation's principal source of petroleum is still domestic crude oil and natural gas liquids production, which provided more than two-thirds of U.S. petroleum consumption in 1983. This figure is projected to remain remarkably level over the rest of the 1980's as Alaskan oil and enhanced oil recovery techniques substitute for the steady decline in production from conventional sources in the Lower-48 States.

Following the 1979-1980 world oil price increase, domestic oil and drilling increased sharply until late 1981, giving way to an equally sharp decline in 1982. Drilling appeared to stabilize in 1983. The sharp downturn in drilling activity has not resulted in a comparable decrease in reported production, although new discoveries are down. It is expected that, with continued depletion of the resource base, the average volume of crude oil discovered per foot of well drilled will continue to decline. Recent exploratory activity continues to bring pleasant and unpleasant surprises in the remaining offshore frontier areas. For instance, there are indications of significant new reserves in a number of areas, most notably offshore California, while there have been costly failures in exploration along the Atlantic coast and offshore Alaska.

World oil prices affect U.S. oil and gas production by setting domestic prices and thus stimulating or inhibiting more exploration and development. In these projections, domestic petroleum production could increase by 1.8 million barrels per day in the high case and fall by 1.1 million barrels per day in the low case in 1995. Table ES5 summarizes domestic energy production for the three cases in this report.

Table ES5. Range of Domestic Production for the Low, Middle, and High World Oil Price Cases (Quadrillion Btu)

Fuel	1973	1978	1983	1990	1995
Petroleum[a]					
Middle	22.1	20.7	20.5	20.8	20.0
Low/High	--	--	--	19.5/22.4	17.5/23.8
Dry Natural Gas					
Middle	22.2	19.5	16.3	16.7	15.3
Low/High	--	--	--	16.7/16.9	14.9/15.8
Coal					
Middle	13.9	14.9	17.3	23.1	26.2
Low/High	--	--	--	23.2/22.9	26.6/25.8
Other Sources					
Nuclear Power	0.9	3.0	3.2	6.3	7.0
Hydro/Other	2.9	3.0	3.6	3.3	3.3
Total Domestic Production					
Middle	62.0	61.1	61.0	70.3	71.9
Low/High	--	--	--	69.1/71.9	69.4/75.8

Source: Table 2 in Appendices A, B and C.
Note: "Low/High" refers to the range of values taken from the low and high cases, respectively.
-- = not applicable.
[a]Includes crude oil, lease condensate, natural gas plant liquids, and other domestic refinery production.

Petroleum Imports

Petroleum imports, which had been declining since the late 1970's, appear to have stabilized in 1983. Net petroleum imports are projected to increase as oil consumption rises as a result of relatively stable energy prices and economic growth, while domestic oil production stabilizes before resuming its long-term downward trend. In the middle world oil price case, net imports increase from a 12-year low of 4.25 million barrels per day in 1983 to about 7.0 million barrels per day in 1995 (Table ES6).

These projections are lower than in earlier years in part because of more optimistic expectations of maintaining domestic supply and in part because lower demand is anticipated.

In the 1982 Annual Energy Outlook, the possibility of substantial switching from natural gas into oil raised import projections by as much as 1.5 million barrels per day. This year, with lower projected gas prices, this possibility is much diminished.

By the early 1990's in the midprice forecasts, large industrial consumers and electric utilities substitute 0.4 to 0.5 million barrels of oil per day for gas. This displacement of gas is forecast to occur because in some regional markets the delivered price of gas rises above the price of competitive oil products. In the low oil price forecast, oil demand grows more rapidly and domestic oil production is less resilient than in the midprice case. The increase in demand for oil stemming from lower prices and higher levels of economic activity is further encouraged by increased substitution of oil for gas as changes in relative fuel prices lead to increased displacement of gas by oil, particularly in electric utilities. The net impact of all of these factors in the low oil price case is to increase oil imports by as much as 2.9 million barrels per day over the midprice case. By contrast, in the high oil price forecast, the price induced drop in demand for oil products and concurrent lower economic activity combine to reduce domestic oil demand. Under the circumstances forecast in the high oil price case, natural gas prices remain more competitive, allowing gas to maintain higher market shares, especially in electric utilities. Overall, in the high oil price case, net oil imports are only 3.6 million barrels per day by 1995; this level is 3.4 million barrels per day lower than in the midprice case.

Table ES6. Net Imports of Crude Oil and Petroleum Products
(Million Barrels per Day)

World Oil Price Case	1973	1978	1983	1985	1990	1995
Middle	6.02	8.00	4.25	5.2	6.0	7.0
Low	--	--	--	5.6	7.4	9.9
High	--	--	--	4.9	4.3	3.6

Source: Table 15 in Appendixes A, B, and C.
-- = Not applicable.

Natural Gas

Projections for natural gas prices in 1985, when 50-60 percent of domestic production is to be decontrolled under the Natural Gas Policy Act of 1978 (NGPA), have undergone a number of revisions in recent years. In 1978-80, it was projected that gas prices would rise too slowly to reach free-market levels by 1985, causing a major increase or "fly-up" in prices upon decontrol. After 1981, oil prices fell, while average gas prices rose faster than expected, leading to the current situation in which the average price is already at market-clearing levels in some markets. For a time, the concern about "fly-up" was supplanted by concern that contracts with price escalators would push prices above market-clearing levels before or upon decontrol in 1985. The recent development of increasingly free markets in gas has changed this view as well. In large part because of substantial competition between oil and gas as boiler fuel, the price of natural gas delivered to large users in some regions is now projected to be adjusted, where necessary, to follow that of oil. The extent to which large consumers will respond to this increased competition by switching consumption between oil and gas is a potential source of uncertainty in the forecasts presented here.

> The Natural Gas Policy Act of 1978 (P.L. 95-621) established a pricing structure that put most gas under price ceilings based on the geology, distance from other wells, location, depth, vintage, and existing contractual agreements for the gas. Price ceilings for new gas were allowed to increase somewhat faster than inflation, but the Act limited increases in the price of "old gas" to the rate of inflation. One category, so called "deep gas," has already been decontrolled. A larger share of gas production is to be decontrolled in 1985, and an additional smaller share will be decontrolled in 1987.

Upon enactment of the NGPA, pipeline companies that had been previously unable to obtain sufficient supplies bid aggressively for new and uncontrolled gas, often signing stringent "take-or-pay" contracts with various price escalators. These committed the pipeline to pay for minimum specified quantities of gas even if this gas were not accepted for delivery because it could not be sold--an event that few foresaw following the gas shortages of the 1970's. Some contracts also contain provisions that upon decontrol the wellhead price of gas would be priced at parity with fuel oil. A large share of contracts contain "most-favored-nation" clauses which require that the gas covered by the contract receive a price as high as that paid to other producers in the area.

The payment of high prices for certain categories of gas was made possible because pipeline sales to gas distribution companies are made at prices that reflect the pipelines' average cost of gas. Thus, many pipelines sell gas to distribution companies for less than the price paid for their incremental (highest-cost) natural gas sources. The cost of gas to end-users has risen as more high-cost gas has been averaged in with declining amounts of cheaper gas.

The decline in industrial and utility demand has forced gas producers and pipelines to confront the consequences of the contract-induced pricing situation. At the same time that demand was declining due to recession, mild weather, and higher prices, the price increase was being further exacerbated by "take-or-pay" contracts for new and high-priced gas. The result was a situation in which producers were willing to supply more gas than consumers would buy at prevailing prices. In particular, utilities and large industrial customers with facilities capable of using either oil or gas (dual-fuel consumers) began to switch away from gas.

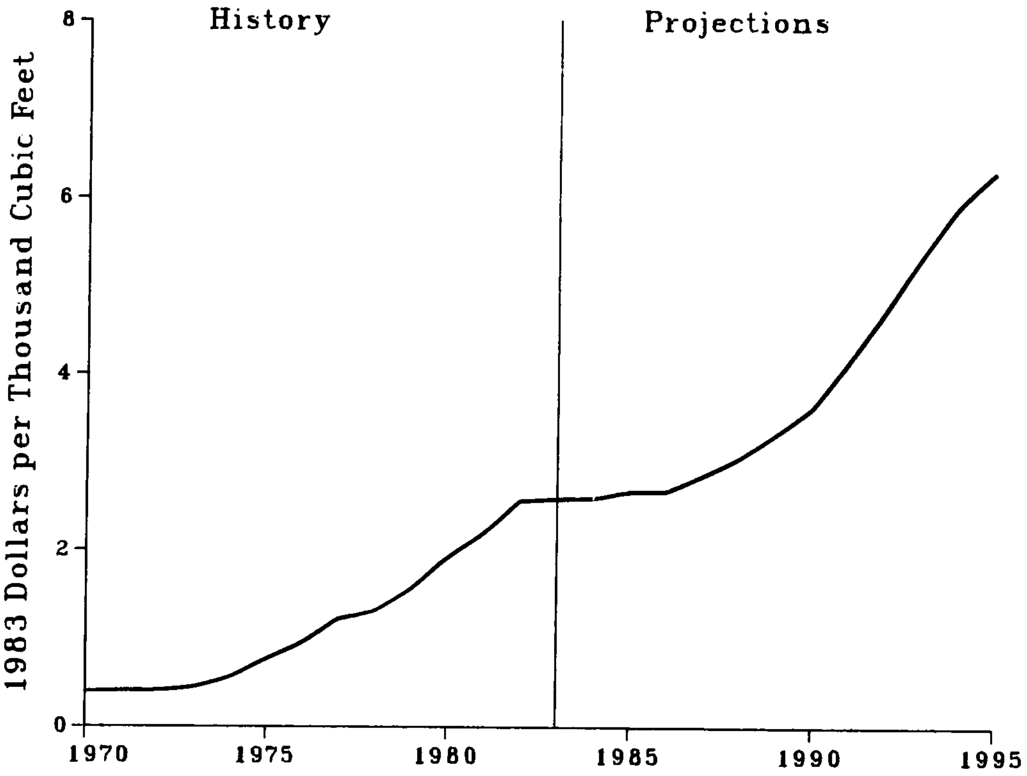
In response to these conditions, a number of actions have been taken to reduce gas prices and restore gas demand. To reduce wellhead prices, there has been extensive recourse to market-out clauses, contract renegotiation, and outright refusal to either take or pay, via imaginative use of legal clauses including force majeur. It is assumed that this trend in response will continue despite litigation over the details.

Small but significant introduction of industrial sales programs and contract carriage arrangements has made it possible to market gas to consumers who would not have bought under prevailing price terms because fuel oil was cheaper. This has benefitted producers facing loss of sales as well as pipelines and consumers. Finally, a number of Public Utility Commissions have permitted flexible pricing programs in which distributors reduce prices charged dual-fuel consumers to levels low enough to prevent fuel switching.

In 1985, over half of domestic natural gas production will be freed of price controls under the NGPA. Because of the market conditions of the last few years, it is believed that most of the price effects that would be expected to result from the deregulation of gas have already been seen. Therefore, in contrast with earlier forecasts, no significant gas price "flyup" is projected in these forecasts. By 1985, in the midprice case, the price of low-sulfur residual fuel oil is the constraining factor in the industrial and electric utility sectors in key regions of the country. While natural gas prices to residential and commercial consumers are forecast to continue to rise, gas prices to electric utility and dual-fuel industrial consumers could be adjusted to compete with oil prices where necessary. Because of the differences in transportation costs and regional use for the major fuels, the relative competitive positions of each fuel can be expected to vary significantly among regions. On average, natural gas is not projected to equilibrate nationally with the price of fuel oil.

The range of projected national average wellhead prices for natural gas is presented in Figure ES1. Currently, new contracts for gas are being made at prices below the regulated ceilings, but at about the average cost of gas paid by the interstate pipelines. Through 1984, the average wellhead price of natural gas is projected to remain unchanged as a result of continued weakness in new contract prices. Up to 1990, prices rise gradually in line with the price of oil. Post-1990, higher oil prices imply continued demand for gas, and this plus the effects of accumulated depletion of the reserve base will increase bid prices for

Figure ES1. Wellhead Price of Natural Gas, Midprice Scenario, 1970 to 1995



Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0131(83) (Washington, D.C., 1984); Natural Gas Annual, 1982 DOE/EIA-0131(82).

new gas in the 1990's. An additional uncertainty is the possibility of substantially higher gas imports in the 1990's from various sources. This could stabilize gas prices rather more than projected here.

The end-use prices of natural gas projected in this report reflect the assumption that a significant portion of the industrial and electric utility consumers in many parts of the country have the dual-fuel capability to switch from natural gas to oil, and that Public Utility Commissions largely have or will permit preferential pricing to such dual-fuel consumers. In the forecasts, it is assumed that the tariffs charged to gas customers will be adjusted so that there will be little or no loss of gas sales to large customers that have the capability of switching to oil, and that rates charged to "captive" end-users will be increased so that pipelines and distributors recover 50 percent of the revenues foregone through flexible pricing to dual-fuel consumers.

These flexible pricing options do not necessarily mean that residential consumers will pay more for natural gas than they would if gas purchase costs were passed on uniformly to all users. In the latter case, loss of gas sales to consumers capable of switching would reduce pipeline and distributors' recovery of fixed costs to such an extent that it would be necessary to raise residential rates above the levels reached under flexible pricing options.

Gas prices and consumption are affected most directly by assumed world oil prices via the competition for the utility and industrial sector multifuel boiler market. For 1995, relative to the projected values in Table ES6, total consumption increases by 0.4 trillion cubic feet in the high world oil price case and falls by 0.6 trillion cubic feet in the low world oil price case. Relative to the midprice case, the average wellhead gas price per 1,000 cubic feet increases by 37¢ or falls by 65¢ in each case, respectively.

Additional uncertainty about natural gas demand not captured in this range arises from potential competition from other fuels in the residential and commercial market. Due to the franchise area protection offered gas retail distribution companies, it has been traditionally assumed that individual consumers (both residential and commercial) possess little power to influence prices. Certainly they cannot shop for the best gas price as they may be able to shop for heating oil. There are two ways, however, in which consumers bring significant market pressures to bear on retail gas companies.

First, competition among electricity, oil, and natural gas as an energy source for heating and for some appliances does exist where new housing developments are concerned. This competitive pressure on retail price could be expected to increase significantly during a home building expansion era.

Second, in the future, residential gas consumption per customer may face even stronger declines due to conservation since gas heated homes are older, tend to have less insulation, and have older heating appliances. The principal conservation mechanism may be in the replacement of existing furnaces which operate at up to 60-percent efficiency with new-technology furnaces that operate in the 80-90-plus percent range. These new furnaces could also play an important role in increasing new gas hook-ups since the end-use heat value price differential for natural gas, compared to electricity or heating oil, is small. In the new homes market, the gas share has declined from 60 percent in 1971 to 40 percent in 1982 while electricity's share has increased from 30 to 50 percent.

Recent shifts in expectations for the price of natural gas are illustrated by Figure ES2, which displays the remarkable changes in successive EIA forecasts of national average wellhead prices in reports for the years 1981, 1982, and 1983. In the 1981 report, the analysis focussed on the "fly-up" of prices upon decontrol of major categories of gas in 1985. Because a significant supply response in the deregulated market had not been observed in 1981, it was thought to be low, and thus average wellhead prices were projected to be high. For the 1982 report world oil prices were lower, but it was realized that prevailing contract terms were creating a problem which would force gas prices up independently of supply conditions. However, in the 1982 report, the gas market was not considered to be sufficiently responsive to avoid a loss of sales due to switching into oil. Events in 1983 have confirmed that the gas market can most likely adapt; this is the biggest single change in assumptions in the gas forecast in this report.

Coal and Nuclear Power

Although total U.S. coal production has risen significantly since its low point in 1961, coal's share of domestic energy consumption did not rise significantly until after 1978. By 1983, coal accounted for 28 percent of U.S. energy production. Although U.S. coal exports fell from 1982 to 1983, coal exports in this forecast are expected to continue to rise through 1995, although at a slower pace than in the last 10 years.

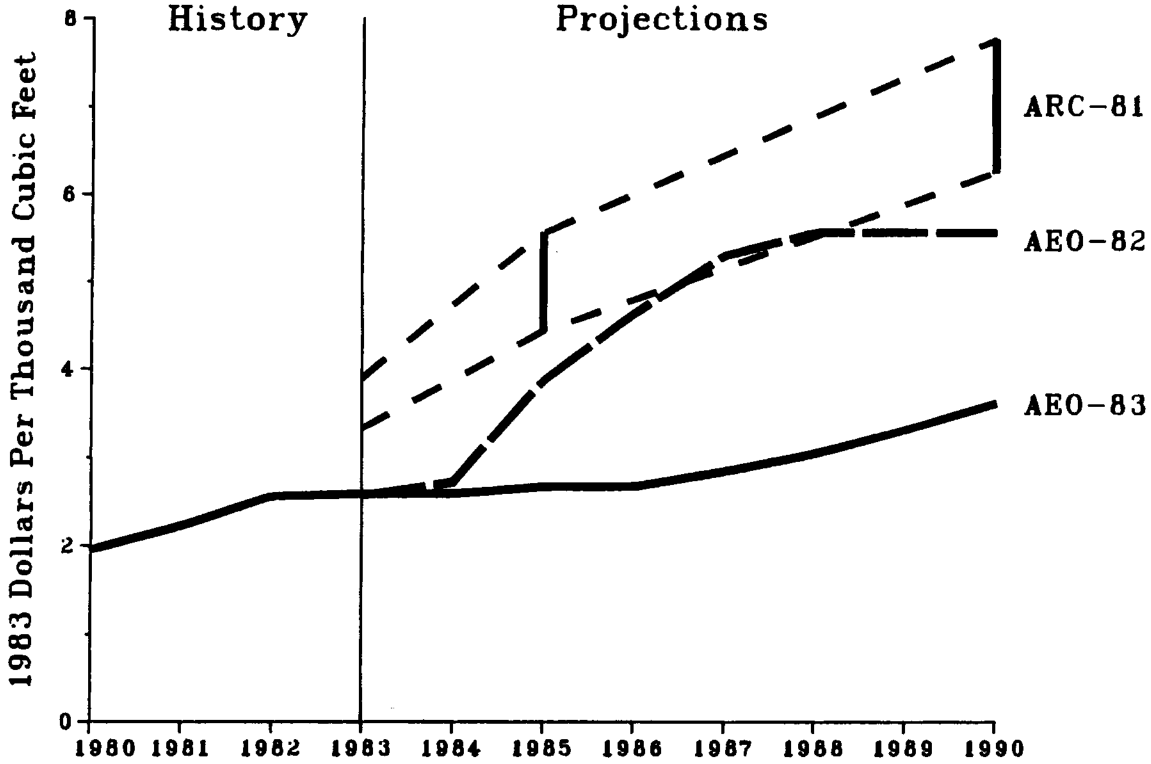
Coal is used primarily as a boiler fuel to generate steam. About 85 percent of domestic consumption is for electricity generation by utilities. Its low cost, relative to competing fossil fuels, has created an incentive for increased consumption, particularly since the large oil-price increases of the 1970's. Over the forecast period, the price of coal at the minemouth is expected to rise less than 1 percent per year in real terms, because of very abundant supplies and the relatively low costs of the expanding surface mining industry. The cost advantage of coal is expected to enhance further the price-competitiveness of electricity.

The outlook for coal consumption and for the location and quality of coal produced is influenced considerably by the Clean Air Act. In this forecast, the mix of coal produced is affected by the permissible levels of sulfur emissions in the consuming regions; State Clean Air Act Implementation Plan standards are assumed to be met by 1984.

Coal is less affected by variation in the assumed world oil price because its consumption is limited principally by coal-fired capacity of electric utilities rather than by price. However, utility generation and industrial demand both respond to variation in economic output driven by oil price changes.

In order to meet domestic and foreign demands, U.S. coal production is forecast to rise by an average of 4.2 percent per year from 1983 to 1990 --to a large extent because of the rebound from the weak economic conditions of the early 1980's--then slow to 2.7 percent per year from 1990 to 1995. Coal is forecast to become the major domestically produced energy source by the late 1980's, contributing 36 percent of U.S. energy production by 1995.

Figure ES2. Wellhead Price of Natural Gas and Successive Price Outlooks, 1980 to 1990



Note: The 1981 report middle and low world oil prices straddled the 1982 and 1983 midprice assumptions. The resulting range of gas prices is indicated by the bars. There were no projections for intervening years.

Sources: Energy Information Administration, Annual Report to Congress 1981, Volume 3 Projections, DOE/EIA-0173(81)/3 (Washington, D.C., 1983); 1982 Annual Energy Outlook, DOE/EIA-0383(82).

Electric utility use of nuclear power is projected to nearly double from 1983 to 1990--rising more rapidly than any other energy source--because of the number of plants now under construction that are expected to be completed. Because of the very long times involved in planning, licensing, and construction, the nuclear projections used in this forecast are based on plants currently under construction. In the forecast, nuclear power's 13 percent share of 1983 utility electricity generation rises to over 19 percent by 1995.

A total of 80 nuclear reactors were in an operable status, and an additional 3 reactors were in low-power testing at the end of 1983. Despite the recent announcements of plant cancellations, 43 reactors are actively under construction; 37 of these are more than 50 percent complete. Nuclear plant cancellations have resulted, in part, from the slowdown in the growth of electricity demand that has affected the entire electric utility industry. In addition, construction cost overruns have been substantial. Over half the nuclear reactors covered in a recent EIA survey had experienced cost overruns of more than 100 percent. The current abundance of uranium is expected to continue to contribute to the low operating costs of nuclear generating plants.

Electric Utilities

In 1983, 35 percent of total U.S. energy consumption was in the form of inputs to electricity generation by utilities, up from 30 percent in 1978. Electricity now provides nearly 14 percent of the energy consumed by end users. The long-term trend toward the use of more electricity has been driven by rising incomes, electricity's high efficiency in end-use applications, and the decline in electricity prices relative to the cost of alternative energy sources. Most electricity is produced from relatively low-cost primary energy sources, such as coal and uranium, which are in plentiful supply.

Despite the advantages of electricity relative to other forms of energy delivered to end users, rising energy prices and swings in economic activity have generally resulted in a slowdown in the growth of electricity consumption since the early 1970's. Sales of electricity are projected to rise somewhat faster than the GNP at annual rates of 3.5 percent from 1983 to 1990 and 2.8 percent from 1990 to 1995. Most of this growth can be attributed to growing demands for electricity in the production of goods and services. In the commercial and industrial sectors of the economy, changes in the level and composition of activities, as well as the introduction of new process technologies, have led to the increasing use of electric power.

Aggregate electricity prices should be stable in real terms until the middle 1990's. Part of the slowdown in electricity demand growth in the 1970's can be attributed to rapid increases in the price of electricity. The price increases were caused by rapid escalation of the prices of oil and gas used as generating fuels and by the impacts of inflation and extended construction time requirements on the cost of building new generating capacity. Over the forecast period, most major plant-building programs are projected to be completed. This will allow utilities to substitute coal-fired and nuclear-power generation for more costly oil- and natural gas-fired sources to meet demand growth. However, the existing oil and gas fired units remain in the rate base and are used to meet seasonal demand. Completion of these programs will also reduce the cash flow pressures on utilities. The combined effects are forecast to result in a national average annual rate of increase for electricity prices of only 0.5 percent. Although not all of the benefits occur equally in all regions, the general trend in electricity prices throughout the country is expected to be moderate.

Disruption Scenarios

The forecasts presented are based on the assumption that world oil prices will not be subject to large, abrupt changes. Although this was clearly not the case in the 1970's, the world oil price changed comparatively little during the two preceding decades. The recurrence of a similarly calm period in world oil markets provides the basis for the assumption of a smooth and gradual rise in oil prices over the forecast period. But the potential instability of oil markets demonstrated during the 1970's cannot be ignored. The actual path of oil prices could be much more erratic than the assumed trend.

For example, if there were a serious disruption to world crude oil supplies, the world oil price could rise significantly. How much prices might deviate from assumed trends would depend on the size of an interruption, its duration, and the response of oil consumption, production, and inventories in the United States and other countries. In the short run, a temporary increase in the price of oil would reduce oil consumption in the United States and, for a time, depress levels of economic activity. A permanent loss of economic well-being could occur because of the lost output during the initial years after the disruption and the lower level of investment and resulting capital stock during subsequent years. Over the longer term, such an incident would reinforce public uncertainty about the availability of energy supplies at stable prices and could give additional stimulus to conservation efforts, synthetic fuels development, and the search for stable trading relationships.

1. Introduction

This edition of the Energy Information Administration (EIA) Annual Energy Outlook presents projections of energy production, consumption, and prices. The report examines both domestic and international energy markets and describes how changes in these markets may evolve through 1995.

This volume differs from its predecessor, the 1982 Annual Energy Outlook, in that the forecasts have been extended to 1995. Short-term forecasts are not discussed in detail in this volume. The Short-Term Energy Outlook, published each February, May, August, and November, presents and explains projections of energy consumption, production, and prices over the next six quarters.

Although each of the chapters of this report is self contained and may be read independently, the report is designed to provide an organized tour through the energy markets. Thus, Chapter 2 analyzes the international context in which domestic markets may be expected to operate through 1995. Chapter 3 describes important underlying assumptions about the general state of the economy and its growth, as well as important energy regulations. Chapters 4, 5, and 6 comprise the core of the analysis of the domestic market, while Chapter 7 describes the effects of events in energy markets on the more general economy. Chapter 8 gives a brief overview of potential longer term developments. Finally, Chapter 9 compares the results of the EIA analysis with other recent and generally available projections.

The analysis presented in this volume rests on a wide variety of assumptions, which, taken together, represent an assessment of future world prices, economic conditions, and the effects of Federal energy programs. The energy projections presented here are therefore conditional: their accuracy depends upon the reliability of the underlying assumptions. The projections are not statements about what will happen in energy markets, but rather descriptions of likely futures based on what was known at the end of 1983. Complete documentation for the forecasting system used to produce this report will be available later this year.

In a number of cases, the analysis is especially sensitive to a particular assumption or the assumption is itself subject to great uncertainty. Domestic energy projections are, for example, relatively sensitive to the world oil price. Where the projections appear to be particularly affected by an assumption, or where the assumption itself is particularly uncertain, alternative projections have been prepared and alternative possibilities discussed. Thus the projections to 1995, in Chapters 4 to 6, have been made using three different world oil price paths. Similarly, the international chapter attempts to bound world oil price uncertainty by examining its sensitivity to world economic conditions.

The forecasts presented in this volume were prepared using the joint EIA modelling systems as described in the methodology appendix.

Forecasting is an exercise definable in terms of input data, formally constructed models and output results. However, the process of arriving at a decision on how to structure models and set model parameters is an exercise in group judgment. These forecasts represent the product of a sequence of meetings and discussions within the EIA to arrive at a consensus judgment which is described in the volume.

This practice has its virtues and its dangers. A major virtue is that projections reflect the informed judgment of a diverse group of analysts, and are not merely the mechanical product of a series of computerized calculations. The danger is that these judgments may result in unwise or inconsistent adjustment of model structure or parameter values. To guard against this danger all changes are explicitly documented and archived. Continuing scrutiny by all interested parties of EIA's modelling procedures and results is perhaps the only method of assuring responsible forecasting.

2. International Energy Markets

The price of crude oil delivered to the United States has dropped from a peak of $39 per barrel in February 1981 to $29 per barrel by late 1983, as oil consumption in the market economies of the world declined for the 4th consecutive year. The outlook for the world oil market for the rest of the decade and through 1995 remains highly uncertain. Although the base case, the midprice case, assumes that the price of world oil will remain relatively stable for the next several years, uncertainties in the world market call for an assumed range for oil prices (when adjusted for inflation to express constant 1983 dollars) of $22-$31 per barrel by 1986, $29-$46 per barrel by 1990, and $37-$66 per barrel by 1995. It is important to keep this wide range of uncertainty in mind when considering the discussion of future energy markets that follows.

World Oil Prices

OPEC Pricing Behavior

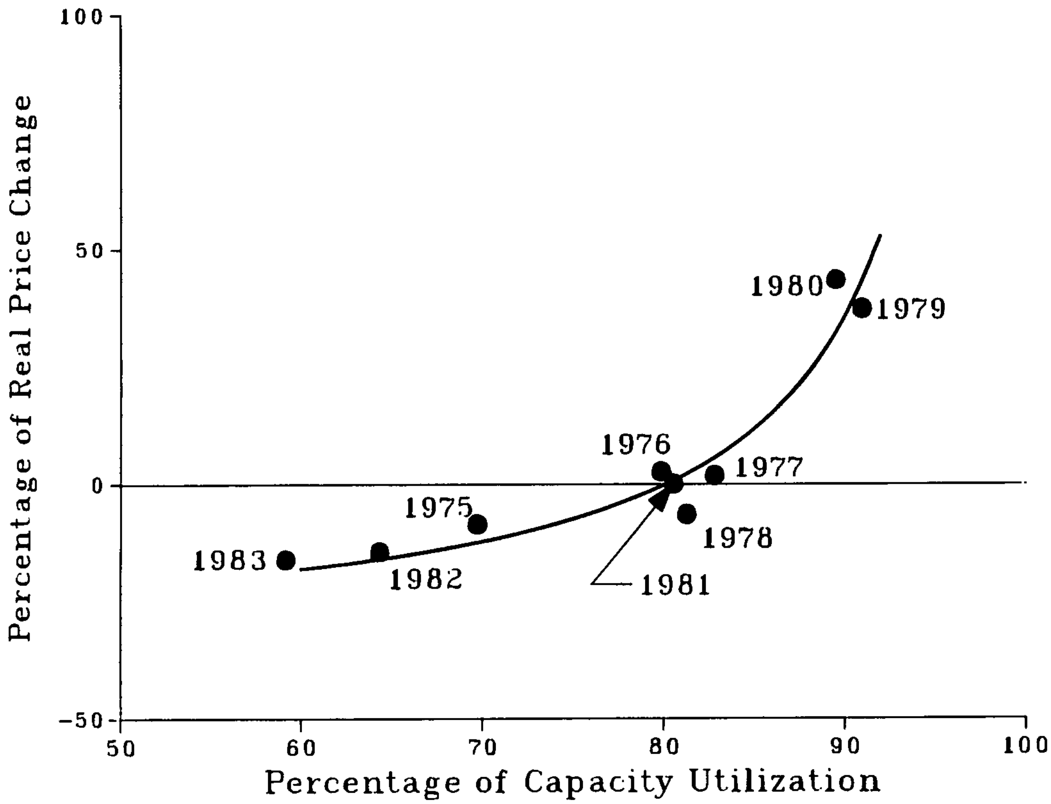
In recent years, the Organization of Petroleum Exporting Countries (OPEC) has seen real prices (adjusted for inflation) for oil drift lower in response to weakened demand. In March 1983, market conditions were such that OPEC took the additional step of reducing prices in nominal terms as well, the first significant price reduction in its history.[1] The marker, or benchmark, price for Arabian Light crude was cut from $34 per barrel to $29 per barrel. OPEC has tended to raise prices in the past when the demand for OPEC oil reaches 80 percent of its production capacity. Figure 1 tracks OPEC's historical price response to changing demands on its production capacity. The relationship illustrated shows the year-to-year changes in the real price (adjusted for inflation) of oil and the associated utilization rates of OPEC production capacity during the 1974-82 period. This relationship is incorporated as an assumption about future world oil price behavior.

Recent Trends

World oil price trends over the past decade are shown in Figure 2. Significant over this period are the price shocks of 1973-74 and 1979-80 and the price decline subsequent to 1980-81. The first price increase followed the oil embargo imposed by the Arab oil-producing countries, and the second followed the Iranian revolution and reduced exports from that country. Between February 1981 and the end of 1983, average prices delivered to the United States were reduced by about 25 percent in nominal terms, going from about $39 to $29 per barrel. When adjusted for the effects of inflation, the real price of U.S. oil imports declined by about 35 percent in less than 3 years.

Several factors have caused world oil prices to decline since 1981. Slow economic growth in the industrial world prior to mid-1983 placed modest demands on world energy supplies. Demands for oil in the developing countries have leveled off considerably in recent years. The price shocks of the 1970's have encouraged increased energy efficiency and conservation as well as increased oil exploration and production throughout the world.

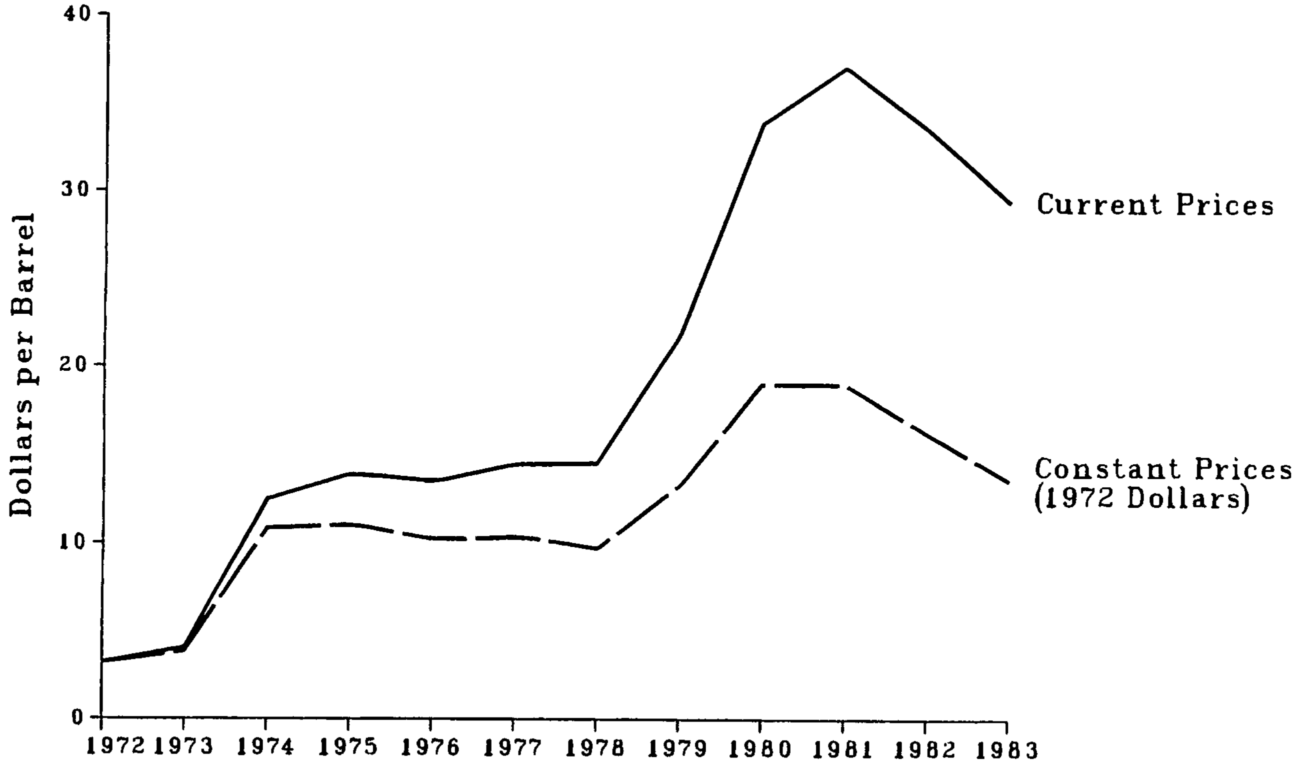
Figure 1. OPEC Pricing Behavior
(Percentage Real Price Change from Previous Year vs. Percent of Capacity Utilized)



Note: Percentage of capacity utilization is derived by dividing OPEC crude oil production for a given year by OPEC maximum sustainable capacity for that year. Production capacity is defined as the maximum production rate that can be sustained for several months. The percentage of real price change from the previous year is derived using the average price of imported crude oil to U.S. refiners. The curve is fitted to historical data using least squares regression. The 1983 value was not used to fit the curve but is presented to demonstrate the applicability of this relationship.

Sources: Historical data: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12[4]) (Washington, D.C., 1984); U.S. Department of Energy, International Affairs, International Energy Indicators; and Central Intelligence Agency, International Energy Statistical Review, selected issues (Washington, D.C.).

Figure 2. World Oil Prices, 1972 to 1983



Sources: Historical data: Calculated using 1972-81 data from: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984). Data for 1982-83 from: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12[4]); and Short-Term Energy Outlook, DOE/EIA-0202(84/1Q).

Economic Factors. Past and projected economic growth rates for the industrialized and developing countries are compared in Figure 3 and Table 1. Prior to the recent economic upturn, economic growth in the industrial countries of the Organization for Economic Cooperation and Development (OECD), measured in terms of real gross domestic product (GDP), had been modest (Table 2).[2] Economic growth in the non-oil exporting developing countries had also slowed in the early 1980's, after fairly rapid growth during the late 1970's. Reduced oil revenues have caused the oil-exporting developing countries to scale back ambitious development programs, thereby causing real GDP in these countries to decline steadily since 1980.

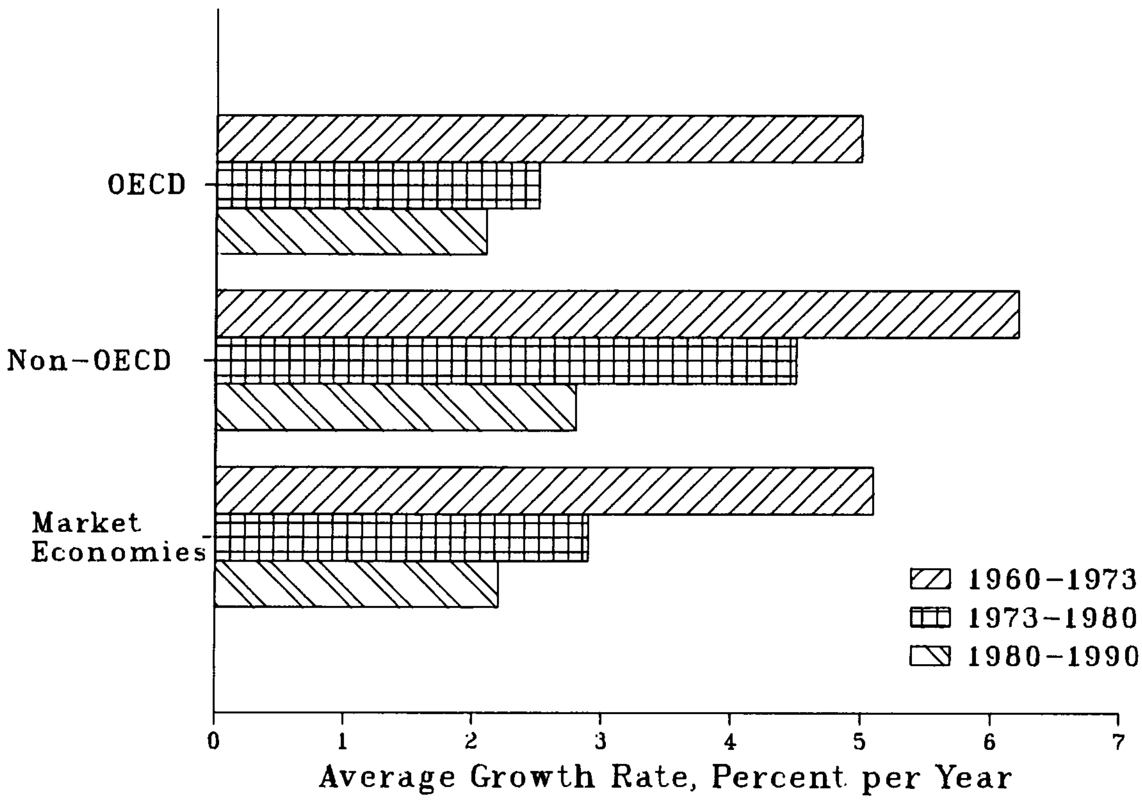
Table 1. Annual Average Compound Growth Rates of Real Gross Domestic Product[a]
(Percent)

Region	1960-1973	1973-1980	1980-1990
United States	4.1	2.2	2.7
Canada	5.5	2.9	1.8
Japan	9.9	3.7	3.1
Western Europe	4.8	2.3	1.4
Finland/Norway/Sweden	4.3	2.7	1.9
United Kingdom/Ireland	3.2	1.0	1.1
Benelux/Denmark	4.8	2.2	1.0
West Germany	4.5	2.3	1.3
France	5.5	2.9	1.2
Austria/Switzerland	3.8	1.4	0.8
Spain/Portugal	7.2	2.5	2.1
Italy	5.3	2.8	1.5
Greece/Turkey	6.6	4.0	3.1
Australia/New Zealand	5.1	2.3	2.4
Total OECD	5.0	2.5	2.2
Total Non-OECD	6.2	4.5	2.8
Total Market Economies	5.1	2.9	2.3

[a]Aggregates at 1975 United States dollars and 1975 exchange rates.

Sources: Calculated using data from: Wharton Econometric Forecasting Associates, World Historical Data (Philadelphia, Penn., 1982); and United Nations, Department of International Economic and Social Affairs, Handbook of World Development Statistics, 1982 (New York, N.Y., October 1982).

Figure 3. Market Economies Economic Growth Rates



Note: Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Sources: Historical data: Calculated using data from: Wharton Econometric Forecasting Associates, World Model Historical Data (Philadelphia, Penn., 1982); United Nations, Department of International Economic and Social Affairs, Handbook of World Development 1982 (New York, N.Y., October 1982).

Table 2. International Economic Growth
(Percent Change from Previous Period)

Region	Annual Average 1970-1982	1983[a]	1984[a]	First-Half 1985[a]
OECD Total[b]	2.8	2.1	3.6	2.9
United States[c]	2.7	3.3	5.3	3.6
Western Europe	2.6	0.9	1.7	2.1
Japan[c]	4.5	3.4	4.2	2.8
Other OECD[d]	3.1	0.8	4.5	3.3

[a]Preliminary estimates for Organization for Economic Cooperation and Development (OECD) countries.
[b]Gross Domestic Product.
[c]Gross National Product.
[d]Canada, Australia, and New Zealand.

Source: Energy Information Administration, Short-Term Energy Outlook, DOE/EIA-0202(84/1Q) (Washington, D.C. 1984).

Along with lower rates of economic growth through mid-1983, energy required to produce a given amount of output has also decreased in recent years. Energy per dollar of real GDP in the OECD countries (excluding Greece, Portugal, and Turkey) declined at a rate of 1.7 percent per year after the 1973-74 price shock and 2.5 percent after the 1979-80 rise. Thus, energy saving gains have accelerated as energy conservation and efficiency efforts have taken hold.[3] As a result of all these factors, oil consumption in the market economies of the world declined about 7 million barrels per day between 1979 and 1982.[4] About two-thirds of this amount is estimated to be due to conservation measures or other price-related effects and about one-third due to the worldwide recession and slow economic growth.[5] On the supply side of the ledger, upward pressure on world oil prices was diminished further as oil production in the non-OPEC countries grew by over a third between 1973 and 1983. Increasing oil output from Mexico, the North Sea, and North Alaska explains most of this increase in production.

Short-Term Factors. Oil consumption in 1983 was reduced further by mild weather in the early months and accelerated liquidation of oil inventories. Inventory adjustments, in turn, were affected by expectations of substantial reductions in the price of oil. The anticipated break in oil prices occurred in early 1983 when certain non-OPEC producers reduced their contract prices significantly. Among the OPEC group, Nigeria was the first to reduce prices in order to remain competitive with North Sea oil. Other OPEC producers then agreed to reduce prices for output and to set a ceiling on production of 17.5 million barrels per day. The OPEC actions helped stop the decline in oil prices for the remainder of 1983 and demonstrated, at least temporarily, their ability to adjust output to meet changing circumstances.

Divergent World Oil Prices

Though the price of oil has declined steadily in the United States since 1981, similar reductions in other areas of the world have not occurred because of the significant appreciation of the dollar's rate of exchange. Oil is sold in dollar denominated prices. Most nations in the world have had to pay more to buy the dollars needed to settle oil-purchase transactions. Thus, while the United States has seen declining prices for imported oil in recent years, other industrial countries have seen rising oil prices. This fact further explains recent declines in oil consumption among the market economies.

Many factors influence the performance of exchange rates among countries, but one of the most important factors in the 1970's was the rise in the real price of oil. Exchange rates among the countries of the world have had to adapt just to account for the substantial increase in the real price of this resource. As might be expected, countries most dependent on imported energy, such as Japan, were most adversely affected by the change in oil prices relative to other goods and services. Countries with oil resources of their own, such as the United Kingdom with its North Sea oil, have benefited from the relative price change. The United States, like the United Kingdom, has large oil resources of its own; as a result, its currency appreciated in real terms, particularly against the yen and the currencies of continental Europe. Of course, many factors have contributed to the overall appreciation of the dollar, important among which has been the general level of U.S. interest rates.

When surpluses soften world oil prices, as they have since 1981, the oil market influence on exchange rates can reverse. With oil and oil products accounting for about a quarter of its imports, Japan has seen the yen regaining some of its value relative to the pound sterling and the dollar. The influence of world oil prices on exchange rates should diminish through 1985, however, in response to projected steady world oil prices.

Short-Term Outlook

The nominal price for world oil is projected to halt its decline in the near term, as economic growth continues to pick up. Economic activity in the industrial countries of the OECD began to accelerate during the last half of 1983 and is projected to grow at a rate of about 3.6 percent in 1984. As a result, the decline in oil consumption slowed in 1983. Consumption is projected to rise slightly in 1984, the first increase in oil consumption since 1979. The upturn in oil consumption in 1984 should be relatively modest, however. Actions aimed at increasing energy conservation and efficiency and at fuel substitution will continue to help hold down oil consumption, particularly in the industrialized countries. Financial difficulties will slow oil consumption growth in many of the developing countries. The oil exporting countries in particular have experienced severe deterioration in their international trade balances in recent years. Borrowing heavily to support aggressive development programs, oil exporting countries were squeezed when interest rates soared while oil revenues fell.

Adding to consumption in 1984 will be a moderate resumption of additions to world oil inventories. Reduced in 1983 for the 3rd consecutive year, stocks are projected to grow at a rate of 0.1 million barrels per day in 1984. At the end of 1983, world oil stocks stood at 4.7 billion barrels, or an estimated 101 days supply. This amount compares with an estimated inventory of 85 days just prior to the outbreak of the Iranian revolution in late 1978.[6] Since the price explosion of 1979, the volume of oil in storage has grown relative to total daily requirements.

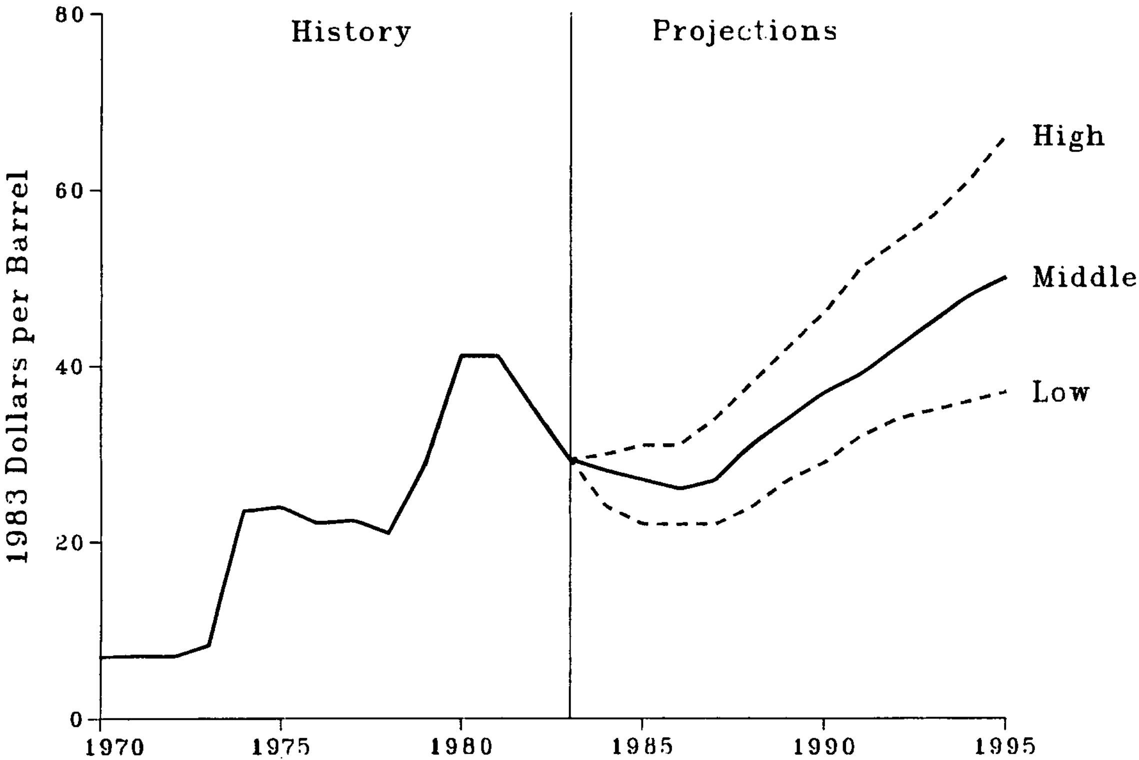
OPEC's March 1983 agreement for production restraint should stabilize oil prices in 1984. As it is, OPEC production is projected to increase about a million barrels per day in 1984, while non-OPEC oil production is projected to increase about 0.6 million barrels per day. The OPEC increase should help reduce tensions regarding market quotas for members seeking larger oil sales.

Longer Term Outlook

Assumed world oil price paths over the longer term are presented in Figure 4 and Table 3. Three different price paths through 1995 are presented. They reflect different assumptions about future oil market conditions and incorporate the projections for 1984 presented in the February 1984 Short-Term Energy Outlook.

Prices under the midprice case are assumed to decline in real terms (1983 dollars) from $29 per barrel in 1983 to a low of $26 per barrel in 1986 and then to rise to $37 per barrel by 1990 and up to $50 per barrel by 1995. That is, prices are assumed to rise at an average annual rate of 3.2 percent between 1983 and 1990 and 6.6 percent between 1990 and 1995. The current 10 to 11 million barrel per day excess in world oil production capacity and the outlook for relatively moderate economic growth in the market economies for the next several years should keep prices down through the mid-1980's. Prices are assumed to rise in the late 1980's, however, as economic growth stimulates oil demand while oil production capacity remains relatively flat. For example, if continued OPEC restraint reduces production capacity to 28.5 million barrels per day (Table 4), OPEC would, considering past behavior, raise prices if its production exceeds 22.8 million barrels per day. Under the midprice case, demands are projected to push OPEC production above 22.8 million barrels per day by 1987. It is assumed that OPEC would then raise prices and raise prices at an accelerated rate as demands grow.

Figure 4. World Oil Price Projections, 1970 to 1995



Note: All prices reflect the average landed price of crude oil in the United States.

Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); Short-Term Energy Outlook, DOE/EIA-0202(84/1Q); and Monthly Energy Review, DOE/EIA-0035(83/12[4]).

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Table 3. World Oil Prices,[a] 1979 to 1995

Year	Low	Middle	High
	Price Case		
	Real 1983 Dollars per Barrel		
1979	28.70	28.70	28.70
1980	41.13	41.13	41.13
1981	41.10	41.10	41.10
1982	35.09	35.09	35.09
1983	29.35	29.35	29.35
1984	24.00	28.00	30.00
1985	22.00	27.00	31.00
1986	22.00	26.00	31.00
1987	22.00	27.00	34.00
1988	24.00	31.00	38.00
1989	27.00	34.00	42.00
1990	29.00	37.00	46.00
1991	32.00	39.00	51.00
1992	34.00	42.00	54.00
1993	35.00	45.00	57.00
1994	36.00	48.00	61.00
1995	37.00	50.00	66.00
	Nominal Dollars per Barrel[b]		
1979	21.67	21.67	21.67
1980	33.89	33.89	33.89
1981	37.05	37.05	37.05
1982	33.55	33.55	33.55
1983	29.35	29.35	29.35
1984	25.00	29.00	31.00
1985	25.00	29.00	33.00
1986	26.00	29.00	36.00
1987	27.00	33.00	41.00
1988	31.00	39.00	49.00
1989	36.00	46.00	57.00
1990	42.00	53.00	66.00
1991	50.00	61.00	79.00
1992	56.00	70.00	90.00
1993	62.00	80.00	101.00
1994	68.00	90.00	115.00
1995	74.00	102.00	133.00

[a]The cost of imported crude oil to U.S. refiners.
[b]Inflation rates used to estimate nominal prices are given in Chapter 3.
Sources: Historical data: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12-2); and Short-Term Energy Outlook, DOE/EIA-0202(84/1Q) (Washington, D.C. 1984).

Table 4. Alternate Projections of OPEC Oil Production Capacities, 1984 to 1995
(Million Barrels per Day)

Country	1984	1990		1995	
		Low	High	Low	High
Crude Oil and Natural Gas Liquids					
Algeria	1.2	0.7	1.0	0.6	0.9
Ecuador	0.2	0.1	0.2	0.1	0.1
Gabon	0.2	0.1	0.2	0.1	0.1
Indonesia	1.7	1.3	1.5	1.2	1.4
Iran	3.2	2.5	3.5	2.5	3.5
Iraq	1.2	3.0	5.0	4.0	5.0
Kuwait	2.0	1.5	1.5	1.5	1.5
Libya	2.1	1.8	2.2	1.8	2.2
Neutral Zone	0.6	0.4	0.5	0.4	0.4
Nigeria	2.2	1.7	1.9	1.6	2.0
Qatar	0.6	0.5	0.7	0.4	0.6
Saudi Arabia	10.0	10.0	11.0	10.0	11.0
United Arab Emirates	2.4	2.0	2.2	2.0	2.2
Venezuela	2.4	2.0	2.2	1.8	2.2
Total	30.0	27.6	33.6	28.0	33.1

Source: U.S. Department of Energy, Office of International Affairs and Energy Emergencies.

EIA Publishes Foreign Energy Supply Assessment Program
Studies on Petroleum Resources of Major Exporters

The Petroleum Resources of Mexico (DOE/EIA-0423), published in October 1983, presents an analysis of the discovered crude oil resources, reserves, undiscovered recoverable crude oil resources, and estimated annual production from oil fields in Mexico. It is the eighth report published by the Energy Information Administration (EIA) under the Foreign Energy Supply Assessment Program (FESAP) of the Department of Energy (DOE). These studies were initiated within DOE to assess the future supply capabilities of various oil-exporting countries. The main objective of FESAP is to assess the quantity of crude oil resources, including undiscovered recoverable resources, in the petroleum exporting countries and the potential rate at which such resources can be produced. This report presents estimates of total recoverable crude oil in Mexico and analyses of the potential rates at which crude oil might be produced and enter into world markets. This analysis does not take into account the possible supply of recoverable resources from such nonconventional deposits as tar sands and oil shale.

In addition to the study on Mexico, five studies have already been published. Two focused on the total petroleum resources of the Republic of Nigeria (DOE/EIA-0008) and of the North Sea area (DOE/EIA-0381). The three others analyzed the crude oil potential of known deposits in the Republics of Venezuela and Trinidad and Tobago (DOE EIA-0297); in the Middle East, including Saudi Arabia, Kuwait, Iran, Iraq, the United Arab Emirates, the Divided Neutral Zone, Qatar, Oman, and Bahrain (DOE/EIA-298); and in North Africa including Libya, Algeria, and Egypt (DOE/EIA-0338). Two additional reports, currently in production, focus on the total recoverable resources of Venezuela, Trinidad and Tobago, (DOE/EIA-0398) and of the Persian Gulf countries mentioned above (DOE/EIA-0395).

The high and low price paths shown in Figure 4 and Table 3 represent an uncertainty range around the midprice case. Developments that have increased uncertainty in the marketplace in recent years and, therefore, the potential volatility of world oil prices are reviewed in the 1982 World Economic Outlook, International Monetary Fund. Prior to 1978, major international companies and some major producing countries sold most of the oil on the world market. This market structure provided the flexibility for ready adjustments in supply to meet changing demands. Since then, major structural changes have occurred as the oil-exporting countries have assumed greater ownership and control of oil operations and have become more directly involved in marketing their product. Oil exporters are also moving into the refining phase of oil operations and are often less likely to provide the secure long-term supplies previously provided by international oil companies.

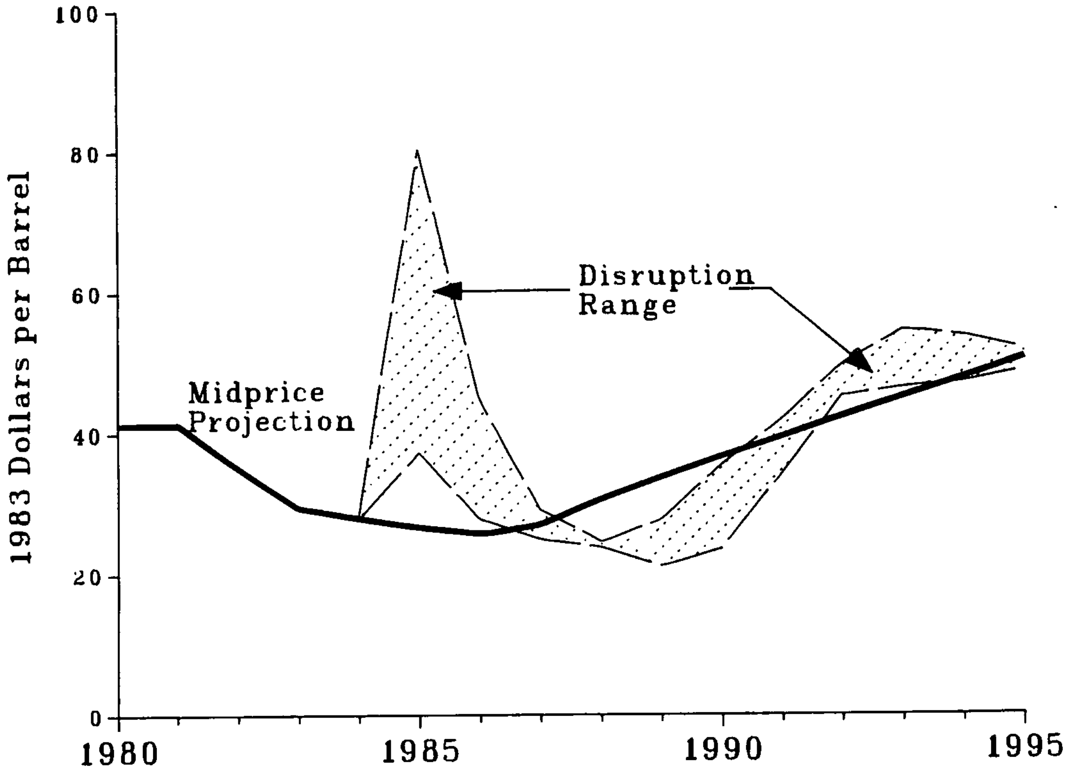
Other changes that have added to the uncertainty in world oil markets include the increasing shift towards short-term contracts and the growing importance of the spot market. This uncertainty has, in turn, increased the variability in world oil inventories. Inventory buildups undoubtedly added to market pressures after the Iranian revolution, as inventory drawdowns undoubtedly contributed to falling prices in the early 1980's. The growing importance of non-OPEC producers has also changed the structure of the market. These producers have been more flexible than OPEC in their pricing decisions, both in terms of quickness and magnitude of price change, in order to penetrate the market.

The three price paths shown in Figure 4 reflect uncertainties associated with general supply and demand pressures at work in the marketplace. The price paths do not consider the additional uncertainty of a major oil supply disruption. Over the last decade, sudden disruptions have caused sharp price increases followed by periods of level or even declining prices. Thus, future price trends might not follow a smooth course as illustrated in Figure 4. Fluctuations in prices of varying degrees may occur again, but their magnitude and timing cannot be predicted. Hypothetical cases are examined below and in Chapter 7.

Petroleum Supply Vulnerability

Figure 5 illustrates possible extremes of the reaction of prices to a hypothetical disruption in oil supplies in 1985. To illustrate just how widely it is conceivable that the future could diverge from the base forecasts

Figure 5. Range of World Oil Prices With Hypothetical Disruption in Supply, 1980 to 1995



Note: The disruption price range is based on a hypothetical disruption that assumes that world oil availability is cut by 10.5 million barrels per day on January 1, 1985, for a period of 12 months.

presented in this report, world oil availability is assumed to be reduced throughout 1985 by approximately 10 million barrels per day. The middle world oil price case is the business-as-usual environment, against which the impacts of a disruption are estimated.

Only an extreme and highly unlikely combination of events would cause such a loss in supply. Smaller reductions in oil availability would cause prices to deviate by smaller amounts from business-as-usual levels. Moreover, there is a substantial range of uncertainty, illustrated in Figure 5, about price impacts of the assumed reduction in world oil availability. The effects of a disruption depend on a number of factors, including the response of energy consumption to higher prices, the availability of replacement oil on the world market, and oil inventory behavior.

How high prices would rise as a result of a given loss in supply depends on the elasticity of demand. The more readily demand responds to price increases, the less will be the price increase required to clear the market at a lower level of availability of supply. Price increases could also be mitigated by raising production up to capacity in nondisrupted nations. However, oil inventory behavior is a significant factor in contributing to the size of the oil price increase. An inventory buildup caused by expectations of higher prices and uncertainty regarding the duration and magnitude of the disruption could exacerbate price increases, while a worldwide draw of commercial inventories down to levels that would not violate minimum operating levels could dampen the price rise. Drawing down the U.S. Strategic Petroleum Reserve and government controlled stocks in other Free World nations could also effect a substantial reduction in oil prices during a disruption. Depending on what is assumed about these factors, a supply disruption of about 10 million barrels per day could increase prices by as little as $10 per barrel or by more than $50 per barrel. As illustrated in Figure 5, the aftermath of a disruption is also unpredictable. When oil supplies are restored (assumed in this example to occur in 1986), world oil prices could fall below business-as-usual levels. This cyclical pattern would arise from the continuing effects on oil demand in the post-disruption period of past high prices and reduced economic activity.

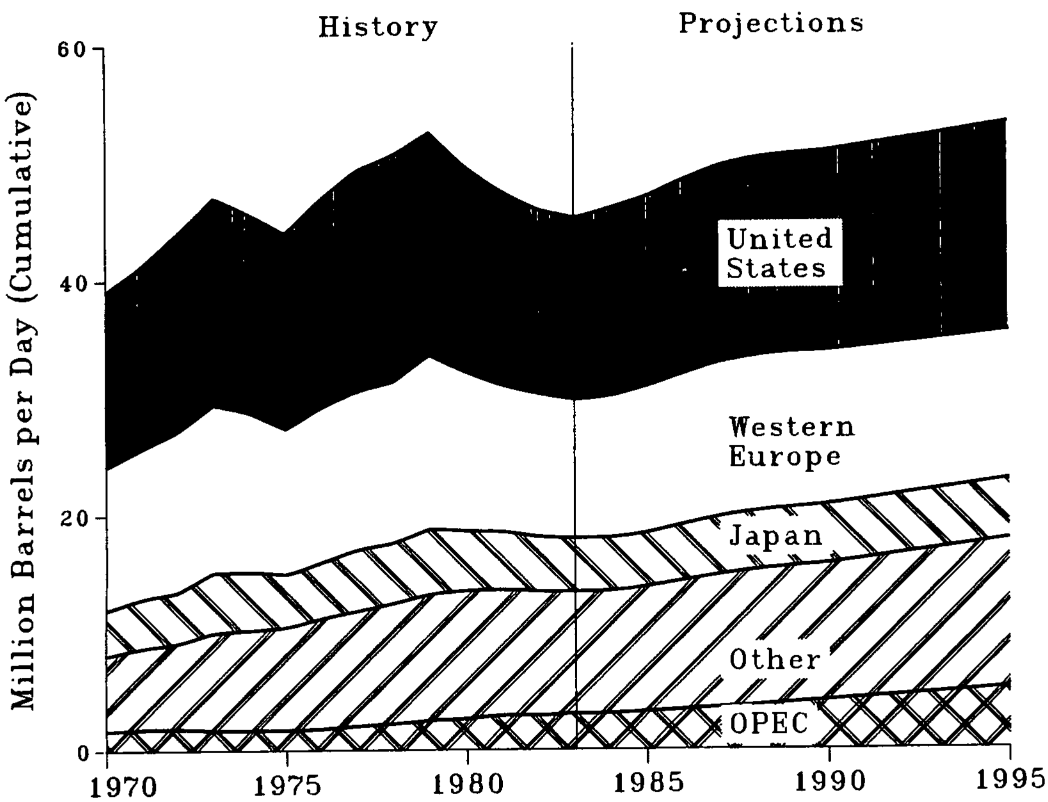
The actual price levels described in Figure 5 are of much less interest than this erratic pattern of price movements. Although prices could rise or fall smoothly, as assumed in the business-as-usual case, the experience of the 1970's suggests that a cyclical pattern of abrupt price increases and declines is also possible.

Oil Demand and Supply

Oil Consumption

Figures 6 and 7 show projected oil consumption and production for the market economies under the midprice case. Oil consumption in the major industrialized countries is projected to grow fairly rapidly between 1983 and 1987 and then level off over the rest of the projection period. Lower world oil prices and improved

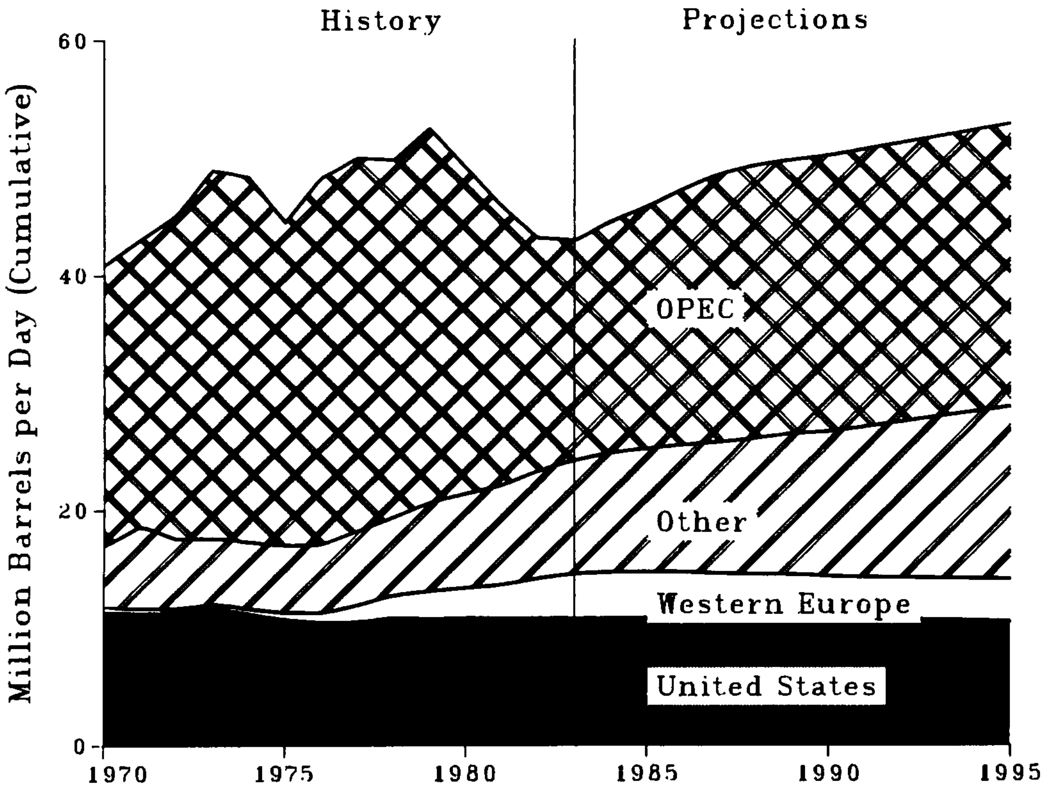
Figure 6. Market Economies Oil Consumption, 1970 to 1995



Note: Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Sources: Historical data: Energy Information Administration, International Petroleum Annual 1978 DOE/EIA-0042(78); International Energy Annual, DOE/EIA-0219, selected issues (Washington, D.C.).

Figure 7. Market Economies Oil Production, 1970 to 1995



Note: Includes natural gas liquids and synthetic liquids. Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Source: Historical data: Energy Information Administration, International Energy Annual, DOE/EIA-0219, selected issues (Washington, D.C.).

economic growth encourages oil consumption in these countries through the mid-1980's. Assumed increases in the price of oil in the late 1980's and early 1990's is the primary reason oil consumption levels off between 1988 and 1995. The share of market-economy oil consumed by the industrialized countries goes down steadily from about 74 percent in 1983 to about 69 percent by 1995.

The shares of oil consumed by OPEC and by the "Other" countries group in Table 5 rise steadily through 1995. With abundant supplies, OPEC consumption is projected to rise by two thirds between 1983 and 1995. Faster growth in oil consumption in the "Other" countries group reflects fundamental, relatively energy-intensive economic development in many of these countries. Tables 6 and 7 show oil consumption and production in the market economies under high and low world oil price assumptions.

Oil Production

Under the midprice case, the "Other" countries group (listed in Table 5) is projected to go from a net importer of oil in the 1980's to a net exporter by the 1990's, largely as a result of Mexico's increased oil production. The industrialized countries are projected to remain net oil importers. Oil production in these countries is projected to decline by about 2.3 percent between 1983 and 1995. Additions to production among the industrial countries will come primarily from the North Sea and offshore areas of the United States and Canada. Gains to future liquid fuel supplies are also expected from enhanced recovery, shale oil, and synthetic liquids.

Oil production in the market economies as a whole is projected to increase steadily through 1995. A large proportion of the additions to oil supplies is projected to come from the OPEC countries. OPEC's share of total market-economies production is projected to go from 43 percent in 1983 to 46 percent in 1995 (Figure 7).

Under the midprice case, the largest percentage gains in production between 1990 and 1995 are projected to come from the "Other" countries group and from Canada. Mexico, currently producing around 3 million barrels per day with natural gas liquids included, is the largest producer among the "Other" countries group and is indeed the fourth largest producer of oil in the world today, following the Soviet Union, the United States, and Saudi Arabia. Other non-OPEC market-economy countries currently producing 100,000 barrels per day or more include: Argentina, Brazil, Colombia, Peru, Trinidad and Tobago, Oman, Syria, Angola, Cameroon, Egypt, Tunisia, Brunei, India, and Malaysia.

Table 5. Market Economies Oil Consumption and Production,[a] History and Projections, Midprice Scenario (Million Barrels per Day)

Supply and Disposition	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.6	15.5	16.0	16.1	16.4	16.7	16.8	16.9	16.9	17.7
Canada	1.9	1.8	1.6	1.5	1.5	1.6	1.6	1.7	1.7	1.7	1.6	1.6
Japan	5.0	4.8	4.6	4.5	4.5	4.5	4.7	4.9	5.0	5.0	5.0	5.1
OECD Europe	13.5	12.5	12.2	11.8	12.1	12.5	12.9	13.2	13.3	13.2	13.1	12.6
OPEC	2.7	3.0	2.9	3.1	3.1	3.2	3.4	3.6	3.8	4.0	4.2	5.2
Other Countries	9.0	8.9	8.9	8.8	8.9	9.1	9.4	9.7	9.8	9.9	10.0	11.1
Total Consumption	49.6	47.4	45.9	45.2	46.1	47.0	48.4	49.7	50.3	50.7	50.9	53.2
Production												
United States	10.8	10.7	10.8	10.8	10.8	10.9	10.9	10.8	10.9	11.0	10.9	10.5
Canada	1.8	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.0
OECD Europe	2.6	2.9	3.4	3.9	4.0	3.9	3.8	3.7	3.6	3.5	3.4	3.6
OPEC	27.7	23.6	19.7	18.6	19.6	20.5	21.7	22.8	23.2	23.3	23.5	24.2
Other Countries	6.3	6.9	7.6	7.9	8.4	8.8	9.2	9.5	9.9	10.3	10.7	12.7
Total Production	49.2	45.8	43.1	42.8	44.5	45.7	47.3	48.6	49.4	49.8	50.2	52.9
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.1	0.6	-0.1	-0.3	-0.4	-0.3	-0.3	-0.3	-0.3	-0.1

[a] Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b] Includes Puerto Rico and Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to total because of rounding.

Sources: Historical data: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(82); Monthly Energy Review, DOE/EIA-0035; and International Energy Annual, DOE/EIA-0219 (Washington, D.C.); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Third Quarter 1983, (Paris, France, 1983); and Petroleum Economics Limited, Quarterly Supply/Demand Outlook, (London, England, 1984).

Table 6. Market Economies Oil Consumption and Production,[a] History and Projections, Low Price Scenario (Million Barrels per Day)

Supply and Disposition	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.6	15.5	16.0	16.4	16.9	17.2	17.5	17.6	17.7	19.5
Canada	1.9	1.8	1.6	1.5	1.5	1.6	1.7	1.8	1.8	1.8	1.8	1.8
Japan	5.0	4.8	4.6	4.5	4.6	4.7	4.9	5.2	5.4	5.4	5.5	5.8
OECD Europe	13.5	12.5	12.2	11.8	12.3	13.0	13.5	14.1	14.5	14.6	14.5	14.5
OPEC	2.7	3.0	2.9	3.1	3.1	3.2	3.4	3.6	3.8	4.0	4.2	5.2
Other Countries	9.0	8.9	8.9	8.8	9.2	9.6	9.9	10.3	10.7	10.8	10.8	12.3
Total Consumption	49.6	47.4	45.9	45.2	46.7	48.5	50.3	52.1	53.6	54.2	54.6	59.0
Production												
United States	10.8	10.7	10.8	10.8	10.8	10.8	10.6	10.5	10.4	10.4	10.3	9.3
Canada	1.8	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.9
OECD Europe	2.6	2.9	3.4	3.9	4.0	3.9	3.8	3.7	3.6	3.4	3.3	3.3
OPEC	27.7	23.6	19.7	18.6	20.3	22.1	23.8	25.7	27.1	27.5	28.2	31.9
Other Countries	6.3	6.9	7.6	7.9	8.4	8.8	9.2	9.5	9.9	10.2	10.5	12.3
Total Production	49.2	45.8	43.1	42.8	45.1	47.2	49.1	51.1	52.7	53.3	53.9	58.7
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.1	0.6	-0.1	-0.4	-0.4	-0.4	-0.3	-0.3	-0.4	-0.2

[a]Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b]Includes Puerto Rico and Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to total because of rounding.

Sources: Historical data: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(82); Monthly Energy Review, DOE/EIA-0035; and International Energy Annual, DOE/EIA-0219 (Washington, D.C.); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Third Quarter 1983, (Paris, France, 1983); and Petroleum Economics Limited, Quarterly Supply/Demand Outlook, (London, England, 1984).

Table 7. Market Economies Oil Consumption and Production,[a] History and Projections, High Price Scenario (Million Barrels per Day)

Supply and Disposition	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Consumption												
United States[b]	17.5	16.5	15.6	15.5	16.0	16.0	16.1	16.2	16.1	16.0	16.0	16.0
Canada	1.9	1.8	1.6	1.5	1.5	1.5	1.5	1.6	1.5	1.5	1.5	1.4
Japan	5.0	4.8	4.6	4.5	4.5	4.4	4.5	4.6	4.6	4.6	4.6	4.5
OECD Europe	13.5	12.5	12.2	11.8	12.0	12.2	12.3	12.2	12.1	12.0	11.9	11.2
OPEC	2.7	3.0	2.9	3.1	3.1	3.2	3.4	3.6	3.8	4.0	4.2	5.2
Other Countries	9.0	8.9	8.9	8.8	8.7	8.8	8.8	8.9	9.1	9.2	9.3	10.1
Total Consumption	49.6	47.4	45.9	45.2	45.8	46.0	46.7	47.1	47.2	47.4	47.4	48.4
Production												
United States	10.8	10.7	10.8	10.8	10.8	10.9	11.0	11.1	11.4	11.6	11.6	12.2
Canada	1.8	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	2.1
OECD Europe	2.6	2.9	3.4	3.9	4.0	3.9	3.8	3.7	3.6	3.6	3.5	3.8
OPEC	27.7	23.6	19.7	18.6	19.3	19.4	19.8	19.9	19.6	19.2	19.0	16.8
Other Countries	6.3	6.9	7.6	7.9	8.4	8.8	9.2	9.5	9.9	10.4	10.9	13.2
Total Production	49.2	45.8	43.1	42.8	44.2	44.7	45.5	46.0	46.2	46.4	46.7	48.1
Net Exports from Centrally Planned Economies	1.2	1.5	1.7	1.8	1.7	1.6	1.5	1.4	1.3	1.2	1.0	0.5
Stock Withdrawals and Discrepancies	-0.8	0.2	1.1	0.6	-0.1	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3	-0.1

[a]Includes crude oil, natural gas liquids, refinery gains, hydrogen, and other hydrocarbons.
[b]Includes Puerto Rico and Virgin Islands.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to total because of rounding.

Sources: Historical data: Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(82); Monthly Energy Review, DOE/EIA-0035; and International Energy Annual, DOE/EIA-0219 (Washington, D.C.); Organization for Economic Cooperation and Development/International Energy Agency, Quarterly Oil Statistics, Third Quarter 1983, (Paris, France, 1983); and Petroleum Economics Limited, Quarterly Supply/Demand Outlook, (London, England, 1984).

World Energy Consumption

General Trends

Total primary energy consumption in the market economies is projected to grow at an average annual rate of about 2 percent between 1983 and 1995 (Figure 8 and Table 8). Energy consumption is projected to grow in all major regions of the market economies, but the Pacific OECD region (Australia, New Zealand, and Japan) and the developing countries (including the OPEC countries) are projected to experience the fastest rates of growth through 1995--the Pacific OECD up by about 30 percent and the developing countries up by about 58 percent from 1983 levels.

Energy consumption in the developing countries group is projected to grow rapidly in response to high levels of economic growth. Several newly industrialized countries in this group should experience fairly rapid growth over the projection period. Important among these countries are Mexico, Brazil, South Africa, and the free port of Hong Kong, though debt problems continue to add uncertainty to the near-term prospects for certain of these and other countries. Rapid growth is also anticipated for certain export-intensive economies, such as South Korea, Taiwan, and Singapore. Additionally, many of the major oil-exporting countries are attempting to use their resources to diversify and expand their economic base. As mature economies, the industrial countries of the OECD already consume vast amounts of energy. Percentage growth in energy consumption in the OECD countries will proceed more slowly given this large base.

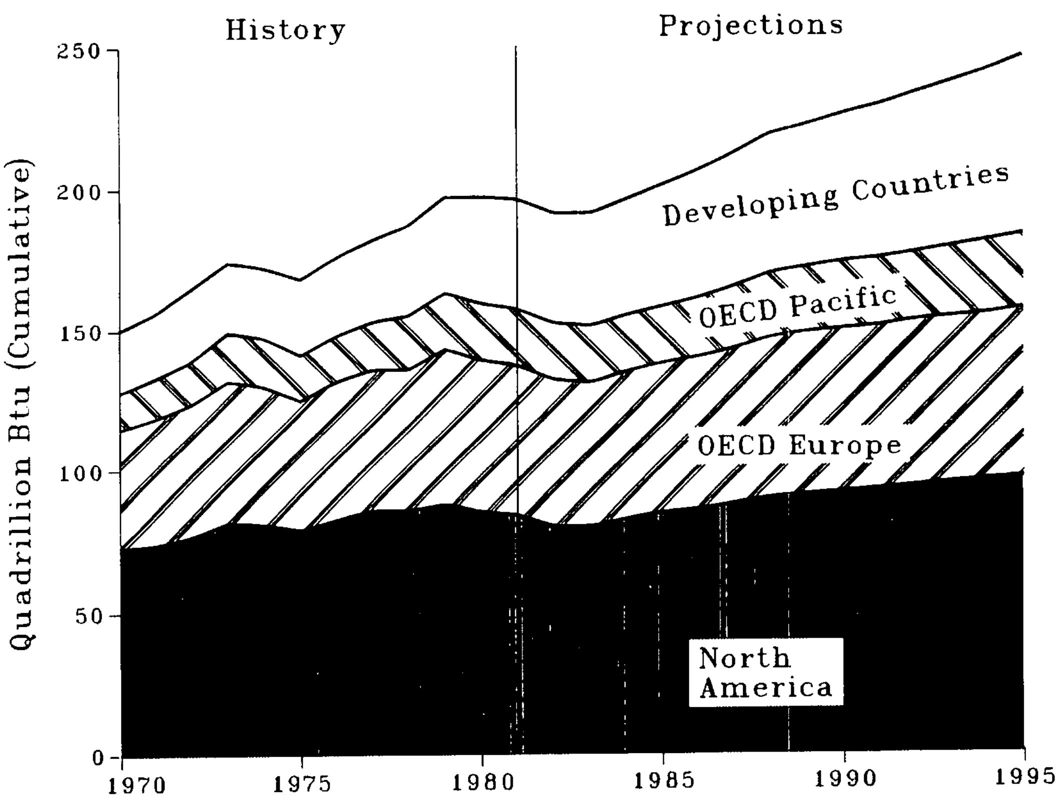
Fuel Shares

The share of total primary energy provided by oil is projected to decline steadily through 1995, going from about 48 percent of the total in 1983 to about 44 percent of the total by 1995 (Figure 9). Its relatively high price and projected flat supply are expected to encourage continued switching away from this fuel, particularly for industrial and electric utility uses. Increased natural gas production and increased gas exports from Algeria and the Soviet Union should also encourage reduced oil consumption, particularly in Western Europe. The share of total energy provided by natural gas falls over the projection period, however, going from 18 percent in 1983 to 17 percent by 1995.

Coal and nuclear power are projected to increase their shares of total energy consumption through 1995. Coal's share is projected to increase from 22 percent in 1983 to 23 percent by 1995. Nuclear's share goes from 4 percent to 7 percent over the same period. The share of total energy derived from all other sources, principally hydroelectric and geothermal, goes from 8 percent in 1983 to 9 percent in 1995.

Coal is abundant in the United States and in several other industrial countries, but its use in other countries could be constrained by transportation considerations. Environmental concerns could also limit its general use. In descending order, the major producers of coal today are: the United States, the Soviet

Figure 8. Market Economies Consumption of Energy by Regions, 1970 to 1995



Note: Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Sources: Historical data: United Nations, 1981 Yearbook of World Energy Statistics (New York, N.Y., 1983); British Petroleum Company Limited, BP Statistical Review of the World Oil Industry 1979 (London, England); and Energy Information Administration, International Energy Annual, DOE/EIA-0219, selected issues (Washington, D.C.).

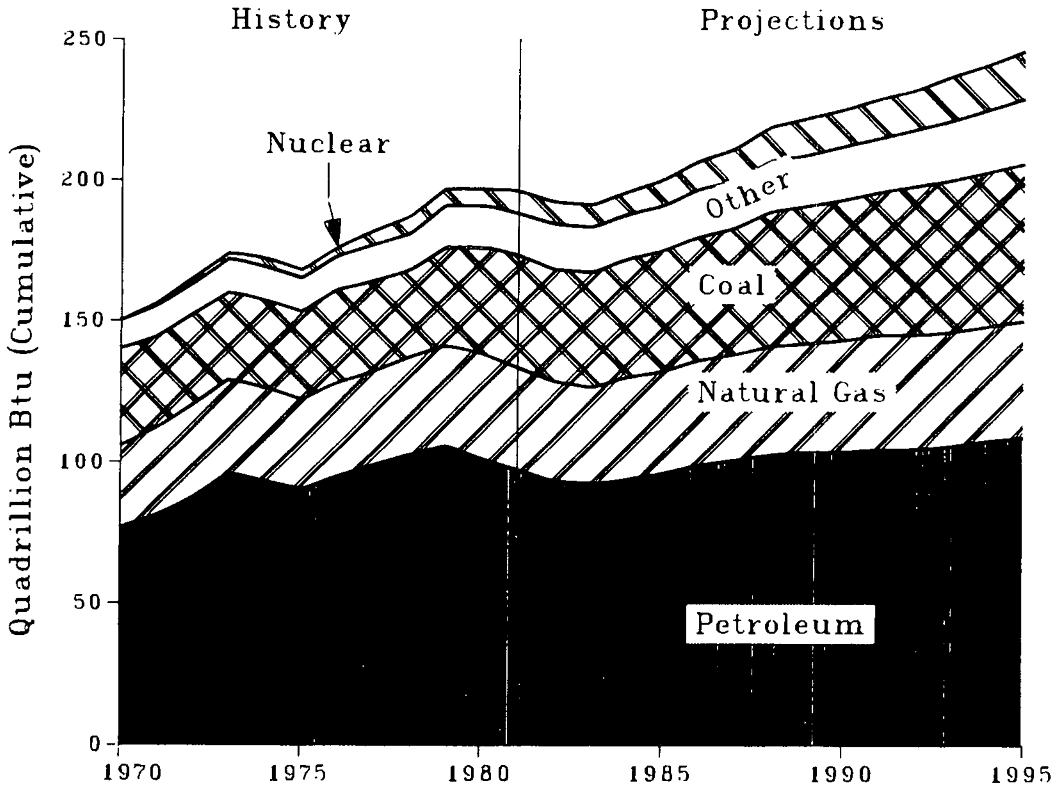
Table 8. Market Economies Apparent Energy Consumption, History and Projections, Midprice Scenario
(Quadrillion Btu)

Regions and Fuels	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1995
Total OECD	157	152	151	155	158	162	165	170	172	173	183
North America	84	80	80	83	85	86	88	90	91	92	97
OECD Europe	53	52	51	52	53	54	55	57	58	58	60
OECD Pacific	20	20	20	20	20	21	22	23	23	24	26
Developing Countries	39	39	40	41	43	45	47	49	50	52	63
Total Market Economies	196	191	191	197	201	207	212	218	222	225	246
Fuel											
Oil	97	93	92	94	96	99	101	103	104	104	109
Natural Gas	36	35	34	36	36	37	37	38	38	39	41
Coal	40	40	41	42	43	44	45	48	49	50	56
Nuclear	8	8	8	8	9	10	11	12	13	13	17
Other	15	16	16	16	16	17	17	18	18	19	23
Total	196	191	191	197	201	207	212	218	222	225	246

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to total because of rounding.

Source: Historical data: Derived from Energy Information Administration, 1982 International Energy Annual DOE/EIA-0219(82) (Washington. D.C., 1983).

Figure 9. Market Economies Consumption of Energy by Type, 1970 to 1995



Note: Market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

Sources: Historical data: United Nations, 1981 Yearbook of World Energy Statistics (New York, N.Y., 1983); British Petroleum Company Limited, BP Statistical Review of the World Oil Industry 1979 (London, England); and Energy Information Administration, International Energy Annual, DOE/EIA-0219, selected issues (Washington, D.C.).

Union, China, East Germany, Poland, West Germany, Australia, South Africa, and India. The use of coal is expected to grow as it displaces oil for electric power generation and for industrial use and as it is used for synthetic fuel production.

Natural gas consumption is projected to increase by about 21 percent between 1983 and 1995. Significant production gains are expected in the developing-countries regions, with smaller gains expected in Western Europe. Currently, the Netherlands, the United Kingdom, and Norway account for about three-quarters of Western Europe's natural gas production. By the mid-1980's, Western Europe is expected to be importing natural gas from the Soviet Union via the Yamal pipeline to supplement domestic supplies. By the late 1980's, the United States is also expected to meet some of its needs for natural gas with additional imported supplies, primarily from Mexico and Canada. Japan is, and should continue to be, a major user of LNG, and Algeria should provide a large share of the internationally traded supplies. Of course, these and other anticipated, international flows of natural gas are dependent upon large capital investments needed to develop the requisite long-distance pipelines and liquefied natural gas (LNG) facilities.

Nuclear energy consumption is projected to more than double between 1983 and 1995. Although projections of nuclear energy consumption have been lowered in recent years, as plans for the development of some nuclear capacity have been postponed or cancelled. Problems confronting this industry include escalating costs for plant and equipment, waste management and other safety concerns, and lower than expected growth in electricity demand. Projections of nuclear generating capacity for the market economies are presented in Table 9.

Table 9. Market Economies Nuclear Generating Capacity, 1983 to 1990
(Million Kilowatts)

Year	United States	Other OECD	Non-OECD[a]	Total
1983	64	87	7	158
1985	72-87	98-121	10-14	180-222
1990	105-114	139-158	17-22	261-294

[a]Includes Yugoslavia.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe, the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers may not add to total because of rounding. Non-U.S. capacity projections are preliminary.

Source: Energy Information Administration, Nuclear and Alternate Fuels Division (Washington, D.C., 1984).

Considerable growth in the consumption of hydroelectric and geothermal power is anticipated, particularly in the developing countries. In 1981, hydroelectric power accounted for about 10 percent of total primary energy consumed in the developing countries. By 1995, it is projected to account for close to 13 percent of the total in these countries. Development of the various synthetic fuels will be constrained internationally as they have been in the United States by rising estimates of project costs and declining estimates of conventional fuel costs.

Comparison of International Energy Projections

Past EIA International Energy Projections

Table 10 presents the EIA midprice projections of energy consumption and oil consumption and production by region for 1990 from the EIA 1977 Annual Report to Congress through the 1983 edition of the Annual Energy Outlook. Projections of 1990 primary energy consumption in market economies have dropped considerably and consistently since the 1977 Annual Report. Projected 1990 energy consumption in the market economies was lowered again this year. Reduced energy consumption in this year's projection results primarily from lowered expectations about growth in oil consumption. Projections of energy consumption have been lowered over the years as high energy prices have encouraged energy conservation and efficiency.

Lower expectations about economic growth in the market economies through 1990 have also lowered expectations about energy consumption.

Lower 1990 oil consumption in the Annual Energy Outlook, 1983 is coupled with lower oil production. OPEC provides the reduction in production levels. In all, the oil production and consumption levels projected for 1990 are in the general range as those made by EIA since the 1979 Annual Report.

Other International Energy Projections

Table 11 compares the EIA midprice case projections with similar projections undertaken recently by other organizations. For purposes of comparison, certain projections were converted from their originally published units to million barrels per day of oil-equivalent. The range of variation in the projections of total energy consumption in the market economies goes from 3 percent in 1985 to about 7 percent by 1995.

Differences in conventions for measuring and defining energy sources and in the availability and reliability of energy information can cause differences in underlying data bases and, therefore, in short-term projections as well. Differences in projection techniques can also affect the estimates. Differences in certain basic assumptions become increasingly important as projections are extended into the future. These assumptions concern the outlook for such factors as economic growth, technological change, energy prices, and energy resource

Table 10. Comparison of EIA Projections From 1977 Through 1983, Midprice Scenario, 1990

Element of Comparison	United States	Japan	OECD Europe	Other Countries	Market Economies
Energy Consumption (quadrillion Btu)					
1977 *Annual Report*	109	33	82	97	321
1978 *Annual Report*	103	26	67	85	280
1979 *Annual Report*	90	24	57	76	247
1980 *Annual Report*	88	24	59	74	246
1981 *Annual Report*	87	23	59	70	238
1982 *Annual Energy Outlook* ..	82	19	60	69	229
1983 *Annual Energy Outlook* ..	82	18	58	67	225

	United States[a]	Japan	Other OECD	Other Countries	Market Economies
Oil Consumption (million barrels per day)					
1977 *Annual Report*	24.2	11.5	26.5	21.0	83.2
1978 *Annual Report*	19.9	7.9	21.1	19.8	68.7
1979 *Annual Report*	16.0	6.3	15.0	15.3	52.6
1980 *Annual Report*	16.0	6.2	15.1	15.2	52.5
1981 *Annual Report*	16.2	5.5	14.3	14.4	50.4
1982 *Annual Energy Outlook* ..	17.4	5.3	16.3	13.8	52.8
1983 *Annual Energy Outlook* ..	16.9	5.0	15.6	13.3	50.9

	United States[a]	OPEC	Other Non-OPEC	Imports from CPE[b] Countries	Market Economies
Oil Production (million barrels per day)					
1977 *Annual Report*	10.1	61.0	14.6	-2.5	83.2
1978 *Annual Report*	11.5	39.7	17.5	0	68.7
1979 *Annual Report*	9.9	26.3	16.4	0	52.6
1980 *Annual Report*	10.1	26.1	16.3	0	52.5
1981 *Annual Report*	10.1	25.7	14.5	0	50.4
1982 *Annual Energy Outlook* ..	10.0	27.7	14.9	0.5	53.1
1983 *Annual Energy Outlook* ..	10.9	23.5	15.8	1.0	51.2

[a]Includes Puerto Rico, the Virgin Islands, and refinery gains.
[b]CPE = Centrally Planned Economies.

Note: Rows may not add to totals because of rounding. In 1983 dollars, the world oil price of a barrel of oil was reported as $20 in the 1977 *Annual Report*, $24 in the 1978 *Annual Report*, $44 in the 1979 *Annual Report*, $48 in the 1980 *Annual Report*, $53 in the 1981 *Annual Report*, $39 in the 1982 *Annual Energy Outlook*, and $37 in the *Annual Energy Outlook*, 1983. Oil stock additions are projected at 0.3 million barrels per day in the *Annual Energy Outlook* issues.

Table 11. Market Economies Energy Projections: Comparison of EIA Midprice Projections with Other Projections for 1985, 1990, and 1995
(Million Barrels per Day of Oil-Equivalent)

Projection	Consumption		Production		CPE Net
	Energy	Oil	OPEC	Other	Oil Export
1981 Actual	95	47	24	22	1.5
1985 Projections					
EIA	98	47	21	25	1.6
Tenneco (August 1982)	100	48	NA	NA	NA
IEA, Paris (October 1982)	NA	48-50	23-26	24-25	1.0-(1.0)
Socal (June 1983)	100	47	21[a]	22[a]	NA
PPA/DOE (October 1983)	98	47	23	23	0.7
DRI (Winter 1983)	NA	47	21	24	1.6
Texaco (December 1983)	101	47	21	24	1.5
Conoco (April 1984)	98	46	19	26	1.0
1990 Projections					
EIA	110	51	24	27	1.0
Tenneco (August 1982)	110	50	NA	NA	NA
IEA, Paris (October 1982)	NA	50-56(b)	27-29	23-25	0.0-(2.0)
Socal (June 1983)	113	49	21[a]	22[a]	NA
PPA/DOE (October 1983)	108	51	26	25	0.0
DRI (Winter 1983)	NA	51	25	26	0.3
Texaco (December 1983)	113	50	25	24	0.5
Conoco (April 1984)	108	48	22	25	1.0
1995 Projections					
EIA	119	53	24	29	0.5
Tenneco (August 1982)	118	52	NA	NA	NA
IEA, Paris (October 1982)[c] ...	NA	54-65[b]	26-29	24-26	0.0-(2.0)
Socal (June 1983)	126	52	24[a]	22[a]	NA
PPA/DOE (October 1983)	118	52	27	25	0.0
DRI (Winter 1983)	NA	54	28	26	(0.6)
Texaco (December 1983)[c]	125	52	29	23	0.3
Conoco (April 1984)	118	51	26	25	0.0

NA = Not available.

[a]Excludes 3.7, 3.9, and 4.3 million barrels per day oil-equivalent of natural gas liquids for 1985, 1990, and 1995, respectively.

[b]Includes 0-4 and 4-12 million barrels per day of excess demand for 1990 and 1995, respectively.

[c]Extrapolated from projections for 1990 and 2000.

Note: The market economies exclude the Centrally Planned Economies of Eastern Europe, the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam. Numbers in parentheses are net imports. Oil consumption and production numbers may not balance because of rounding.

Sources: Tenneco, Energy 1982-2000 (Houston, Tex., 1982); International Energy Agency, World Energy Outlook (Paris, France, 1982); Standard Oil Company of California, Update to World Energy Outlook (San Francisco, Ca., 1983); Office of Policy, Planning and Analysis, Energy Projections to the Year 2010 (Washington, D.C., 1983); Data Resources, Inc. International Energy Bulletin (Lexington, Mass., 1983); Texaco, Free World Energy Survey (White Plains, N.Y., 1983). Conoco, World Energy Outlook Through 2000 (Wilmington, Del., 1984).

availability. The comparisons in Table 11 help to point out the importance of these underlying assumptions and the areas of greatest uncertainty about the future.

Projections of oil consumption are quite similar among the various studies listed in Table 11, with the EIA estimates somewhat at the upper end of the group. Comparing EIA's projections of energy consumption in 1990 with five other projections, including some of those listed in Table 11, the greatest agreement about future consumption among them is about oil. The range of variation for 1990 oil consumption among these studies is not quite 4 percent. Wider differences occur with the projections of coal and "other" energy sources, a 28-percent difference for "other" energy and a 30-percent difference for coal. The largest difference among the studies is for projected consumption of nuclear energy, a variation of 32 percent. This difference in nuclear energy consumption represents about 2 million barrels per day of oil-equivalent. The greatest difference among the projections in absolute terms is for coal consumption, about 6 million barrels per day of oil-equivalent. This amount is also the difference among the projections for total energy consumption in 1990.

Assumptions about world oil prices vary a good bit more than do the projections of oil consumption listed in Table 11. The derivation of three price paths by EIA helps to illustrate the uncertainty involved when considering world oil prices (Table 12). Considering base-case assumptions, the EIA assumption of $50 per barrel by 1995 is at the high end of the price range while the DRI amount for 1995 of about $37 per barrel is at the low end, all prices converted to 1983 constant dollars. The 1995 base case price assumption by PPA/DOE is closer to the EIA amount at about $48-$49 per barrel. Two recent studies not listed in Table 11 that also put 1995 world oil prices in the $47-$49 per barrel range include one by the Central Electricity Generating Board, United Kingdom and the World Bank's World Development Report 1983. The World Bank assumes that real prices will be about 20 percent above the 1981 peak by the mid-1990's.

A survey undertaken in 1983 by the International Institute for Applied Systems Analysis, Laxenburg, Austria, and summarized in its quarterly report, Options, resulted in a median 1995 price for oil of about $53 per barrel, which represents a 2-percent per year rate of increase between 1980 and 2000. The study by Standard Oil of California shown in Table 11 assumes that prices will remain flat in real terms through the 1980's, then rise slowly during the 1990's to a range of about $35 to $50 per barrel by the year 2000. Texaco assumes that prices will decline slightly in real terms over the next few years, rise with the rate of inflation in the late 1980's, and exceed the rate of inflation by 1-2 percent in the 1990's. Conoco suggests that further price declines are a distinct possibility in the near term, with moderate real price increases possible during the second half of the 1980's. To summarize, though varying in degree and timing, most recent studies assume the same general pattern of rising world oil prices after the mid-1980's and into the 1990's.

Table 12. World Oil Prices Sensitivity Analysis
(1983 Dollars per Barrel)

Scenario	1985	1990	1995
	World Oil Prices		
Midprice Case	27.00	37.00	50.00
	Differences from Midprice Case Prices		
Sensitivity Scenario[a]			
High Economic Growth	0.63	2.73	2.34
Low Economic Growth	-0.58	-2.74	-6.29
Low Price Elasticity	-0.12	0.90	8.75
High Price Elasticity	0.12	-1.25	-4.52
Low Income Feedback Elasticity	-0.02	0.29	0.38
High Income Feedback Elasticity	0.02	-0.29	-0.44
Low OPEC Oil Production Capacity	2.30	3.22	6.73
High OPEC Oil Production Capacity ...	-3.48	-6.04	-5.34
Low Non-OPEC Oil Supply	3.22	7.88	10.48
High Non-OPEC Oil Supply	-2.04	-3.24	-10.29
	World Oil Price Range		
Combined Uncertainty[b]			
Low Price Scenario	22.00	29.00	37.00
High Price Scenario	31.00	46.00	66.00

[a]Scenario prices are derived by varying each sensitivity factor separately while holding all other factors at midprice case levels. High and low ranges for the sensitivity factors are -0.4 and +0.4 percent per year for economic growth rates; -25 and +25 percent of estimated price and income-feedback elasticities; -14 to +14 percent of midprice case OPEC production capacity values by 1995; and -11 to +19 percent of midprice case non-OPEC oil supply values by 1995. Midprice case values are presented in Tables 1 and 5 and in Oil Market Simulation Model Documentation Report, DOE/EIA-0412.

[b]The square root of the sum of the squares of the individual high, or low, differentials added to, or subtracted from, the midprice.

Footnotes to Chapter 2

[1]The OPEC members are: Algeria, Ecuador, Gabon, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.

[2]The OECD members are Australia, Austria, Belgium, Canada, Denmark, Finland, France, West Germany, Greece, Iceland, Ireland, Italy, Japan, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, and the United States.

[3]International Bank for Reconstruction and Development/The World Bank, World Development Report 1983, July 1983 (New York: Oxford University Press, 1983).

[4]In this chapter, the market economies include all countries other than the Centrally Planned Economies of Eastern Europe (including Yugoslavia), the Soviet Union, China, Cuba, Kampuchea, North Korea, Laos, Mongolia, and Vietnam.

[5]Meloe, Tor, Chief Economist, Texaco, Inc., "The Impact of Conservation on Future Oil Demand," a paper presented at the 12th Annual Convention of the Indonesian Petroleum Association (Jakarta, Indonesia, June 1983).

[6]Energy Information Administration, Short-Term Energy Outlook, DOE/EIA-0202(84/1Q) (Washington, D.C., 1984).

3. Assumptions for Domestic Energy Analysis

Overview

Energy markets in the United States have undergone dramatic changes since the end of World War II. During the postwar period, the Nation shifted from a general dependence on coal as the primary fuel to increasing reliance on natural gas and oil. Supplies of these fuels were abundant and inexpensive. Consumers preferred them to other fuels because they were clean, convenient, and economical. By the end of the 1960's, however, domestic production of oil and gas began to level off and the Nation became increasingly dependent on imported energy.

The significance of that reliance and the vulnerability of the United States to disruptions of supply and abrupt changes in price became apparent in 1973 when the Arab members of OPEC embargoed oil shipments to the United States. The ensuing tripling of price and accompanying recession caused oil consumption and imports to decline during the next 2 years. Although domestic oil consumption began to grow again in 1976, U.S. oil consumption peaked in 1978, then declined through 1983, following the doubling of world oil prices from 1978 to 1980.

Although the future price of oil is uncertain, and there has been a recent, significant downward pressure on oil prices, it is unlikely that energy prices will return to levels that prevailed in the 1960's. Individuals and firms have long since begun to make appropriate adjustments in response to higher energy prices. At first, short-term changes (reductions in the amount of driving, for example) appeared. Changes toward more energy-efficient houses, cars, and factories, and adjustments toward less expensive fuels usually require investments to be made and are spread over a number of years. Many variables affect the rate at which these adjustments take place.

For example, the level of investment influences the rate at which new (and presumably more energy-efficient) industrial plants are built. Interest rate levels influence the rate of new home construction and new car sales, and, hence, the extent to which the stocks of homes and autos change in response to more recent energy prices. The speed at which adjustments to the higher energy prices can be expected to take place is thus affected by the more general economic environment. Some of these relationships will be explored in the succeeding chapters.

A great many specific assumptions about behavior and the state of the world underlie the forecasts presented in the next three chapters. Three assumptions are of central importance in determining the general shape of the projections--assumptions about the world oil price, the state of the economy, and the general state of Federal regulation.

Date of Forecast Assumptions

Most forecasts presented in this volume are based on assumptions made in October 1983. Unanticipated events, new legislative enactments, or other major changes in the state of the world would clearly modify the assumptions and result in somewhat different forecasts.

World Oil Price

The world oil price trajectories used to construct the base (or middle world oil price) projections are shown in Table 13, together with high and low world oil price trajectories. Events in the world oil market over the past 3 years have led to the assumption that the world oil price in 1990 will be 37 percent lower than the principal price assumption employed 2 years ago in the 1981 Annual Report to Congress. More generally, the intermittent, sharp, year-to-year swings in the real price of oil since 1970 demonstrate the extreme degree of uncertainty surrounding projections of world oil prices.

The bands of uncertainty around the price paths and the underlying assumptions were discussed in Chapter 2, "International Energy Markets." It is important to note that the paths employed here reflect supply and demand pressures that vary smoothly from one year to the next. Future prices may not vary in such a smooth fashion. As in the past, prices could surge upward suddenly (perhaps due to a supply interruption or conflict in a major supply region) followed by periods of prices that gradually decline (in real terms) during the slack markets that have followed disruptions.

The focus in this report, however, is on basic underlying economic pressures on energy markets rather than on short-term events, or adjustment processes associated with supply disruptions. As discussed in Chapter 2, the basic rationale that underlies the world oil price projection is straightforward. The generalized international recession and adjustments to large, past price increases have caused a worldwide decline in the consumption of oil.

As a result, excess production capacity is currently exerting downward pressure on real oil prices. This downward pressure may persist for some years, perhaps through 1986. Eventually, the resumption of growth in the world economy implies greater oil consumption (despite gains in the efficiency with which oil is used) and a resumption of upward pressure on prices as production capacity becomes pressed.

Macroeconomic Assumptions

Macroeconomic assumptions for EIA's energy projections are developed using a commercially available forecasting model maintained by Data Resources, Inc. (DRI). A standard DRI forecast is modified to reflect EIA's energy assumptions in producing the initial economic assumptions. These assumptions are further modified to reflect energy-economy feedbacks within EIA's energy models. Final base case assumptions are modified to be consistent with world oil price assumptions in Table 13.

Table 13. World Oil Price Projections
(1983 Dollars per Barrel)

Price	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Low	41	35	29	24	22	22	22	24	27	29	32	34	35	36	37
Middle	41	35	29	28	27	26	27	31	34	37	39	42	45	48	50
High	41	35	29	30	31	31	34	38	42	46	51	54	57	61	66

DRI's TRENDLONG0883ANN forecast was used for this year's report. The modified forecast used to make these projections does not differ greatly from DRI's original forecast or from forecasts generally available from other macroeconomic services.

Modification of the DRI growth path for EIA energy prices primarily affects the economy in the 1990-95 period, where the EIA analysis leads to the assumption that there will be more sharply rising oil prices.

Table 14 presents values of important economic variables. Gross National Product--the total value of goods and services produced by the economy in a year--increases over the forecast period (1983-90) at a rate of 3.3 percent a year, more rapidly during the initial years as the economy recovers. The average rate of increase for the remainder of the 1980's is somewhat below the rate of 3.5 percent that prevailed during the period between 1947 and 1980, but about the same as the overall rate of 3.1 percent that occurred during the 1970's. It is considerably above the average rate of 1.9 percent observed from 1973 to 1982 and is in keeping with the recent trends in the economy. Economic growth is projected to slow down in the 1990's, averaging 2.2 percent per year from 1990 to 1995.

Most values for economic output and prices in this report are reported in "1983 dollars." For economic output measures, this means that 1972 constant dollar values have been converted to more-current terms by multiplying by 2.164, a projection of the implicit GNP price deflator in 1983. For prices, this means that the appropriate conversion to current-dollar prices is made by taking prices "in 1983 dollars," and multiplying them by projections for the ratio of the GNP deflator for the given year to the 1983 GNP deflator (Table 14 or Table A.19).

The GNP deflator is only one of several measures of inflation; others include the Producer Price Index and the Consumer Price Index. The GNP deflator is employed here because its broad base makes it useful for evaluating spending throughout the economy. Over the 1983 to 1990 period, the GNP deflator is assumed to increase relatively smoothly at a rate of 5.5 percent. This rate is somewhat below the rate of 7.4 percent experienced since 1973 and reflects recent decreases in inflation.

Disposable income and interest rates are other variables that play important roles in determining energy demands in different sectors of the economy. The level of disposable income is an important determinant of personal energy use. Projected values for these variables are shown in Table 14.

Table 14. Assumed Values of Macroeconomic Variables

Variable	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Real GNP (billion 1983 dollars).............	3,313.1	3,471.8	3,586.3	3,707.9	3,839.8	3,961.5	4,065.4	4,169.4	4,267.2	4,357.0	4,449.6	4,546.9	4,653.2
Percent Change from Previous Year.............	3.1	4.8	3.3	3.4	3.6	3.2	2.6	2.6	2.3	2.1	2.1	2.2	2.3
Disposable Income (billion 1983 dollars).............	2,371.0	2,486.0	2,569.4	2,651.3	2,726.1	2,786.6	2,847.4	2,904.3	2,960.7	3,018.6	3,079.5	3,143.5	3,213.5
Percent Change from Previous Year.............	3.3	4.9	3.4	3.2	2.8	2.2	2.2	2.0	1.9	2.0	2.0	2.1	2.2
GNP Deflator (1972=100).................	216.4	225.8	236.6	248.8	262.0	277.9	295.3	314.2	336.4	360.5	385.3	410.0	435.3
Percent Change from Previous Year.............	4.6	4.3	4.8	5.2	5.3	6.1	6.3	6.4	7.0	7.2	6.9	6.4	6.2
Yield on New High-Grade Corporate Bonds (Percent)..	11.5	11.7	11.5	11.5	11.3	11.0	10.6	10.4	10.5	10.5	10.5	10.2	10.1

Forecasts from Data Resources, Inc.

Federal Regulation

It is the policy of the Energy Information Administration to base its projections on the statutes and regulations that exist at the time the projections are made. As a general rule, changes in Government programs that affect energy industries are not included in the forecasts until the changes have been written into the law. The effects of governmental programs are, however, influenced by general economic and energy market conditions.

The forecasts included in this volume are based on the assumption that the wellhead price controls on certain types of natural gas imposed by the Natural Gas Policy Act of 1978 (NGPA) will be removed according to the schedule contained in the Act.

Subsequent to the publication of the 1982 Annual Energy Outlook (AEO), considerable evidence has emerged suggesting that the natural gas market is considerably more flexible in its response to economic forces than had been anticipated. There is evidence that contracts have been renegotiated both bilaterally and unilaterally and that some public utility commissions are permitting a lesser share of the distribution costs of gas to be passed to industrial and electric utility customers who would otherwise switch to oil. A number of entities, including pipelines, are actively engaged in the brokering of gas, i.e., facilitating the sale of gas directly from producers to customers.

In the 1982 AEO, it was assumed that there would be little or no renegotiation of contracts between gas producers and pipelines, even in the face of substantial losses in sales as utilities and industrial customers moved to residual fuel oil in preference to increasingly expensive natural gas. Further, it was assumed that there would be little change in the relative shares of the fixed costs of pipelines paid by the consumers in the various sectors. Finally, no attempt was made to account for direct sales from producers to industrial users or utilities, sales in which the role of the pipeline is simply to provide transportation. This view of the market produced projections of high natural gas prices and sharply decreased consumption.

When the 1982 AEO assumptions about market behavior are relaxed to take the accumulating evidence of flexibility into account, a projection of much lower natural gas prices emerges. Specifically, the current gas price forecasts are based on the results of negotiations that have already taken place. It is assumed that contracts with "market out" clauses (which allow a purchaser to refuse to purchase gas that cannot be resold at a profit) are reset to the market price each year and that all contracts signed after 1980 have market-out clauses, but that there is no renegotiation of contracts lacking market-out clauses. This has significant implications for the forecasts for energy sources other than gas, especially oil consumption and import levels. These changes in the forecast occur even though the assumption about natural gas regulation has not changed. What has changed is the view of the ability of the natural gas market to react to increased competition from oil.

There are a number of proposed changes in the Clean Air Act that would require retrofitting of existing power plants to meet new emissions standards. The projections contained here, however, are based on the assumption that the current standards will be enforced. Under existing standards, these plants can be used without additional environmental-control equipment or changes in fuels. The projections would change in response to significant changes in environmental regulations.

Two recent significant changes to the tax code are included in the projections presented in this chapter. The macroeconomic assumptions include the personal income tax bracket indexation specified by the Economic Recovery Act of 1981 as was the case in the 1982 AEO. The effects of increased taxes on transportation fuel schedules that went into effect in April 1983 under the terms of the Surface Transportation Assistance Act of 1982 (P.L. 97-424) are also included.

It is assumed that current Federal policies for the leasing of Federal property for exploration and the development of energy resources will remain unchanged and, in any case, not be a constraint on domestic energy production through 1995. In addition, current environmental regulations are assumed to remain in force through the forecast period.

A detailed discussion of the forecast assumptions and methodology is provided in Appendix D.

4. End-Use Energy Consumption

After the 1974 oil embargo, there was considerable uncertainty concerning how much energy would be required to meet domestic needs in the future. Some early analyses indicated that more than 100 quadrillion Btu of primary energy would be required to maintain a healthy U.S. economy by 1990.[1] Since then, such projections have been adjusted downward as energy conservation has exceeded most expectations. This chapter discusses recent energy use trends and presents projections of energy use by the residential, commercial, industrial, and transportation sectors. End-use energy consumption excludes the energy used to generate and transmit electricity to the end-use sectors but includes delivered electricity. Primary energy consumption includes fuels used by electric utilities, but excludes sales of electricity to the end-use sectors. Electric utilities are discussed in detail in Chapter 6 of this report.

Energy consumption in the U.S. economy is based primarily on individual consumer decisions. Consumers demand energy directly in the form of energy services (such as transportation, heat, and light) and indirectly in the form of energy embodied in purchased goods and services (such as automobiles and frozen foods). Total energy consumption is influenced by many factors including energy prices, economic growth, and efficiency improvements.

Energy prices are reflected in the prices of goods and services consumers purchase. They affect daily consumption decisions, as well as major equipment choice decisions. If the cost of energy services (for example, traveling and heating) increases, consumers may purchase less of them. Certainly, for example, as the cost of driving a mile increased after each of the two major gasoline price increases of the 1970's, consumers cut back on their travel. Similarly, the price of energy embodied in products affects energy consumption. If energy prices increase relative to the prices of other inputs to the manufacture of final products, those products that are relatively energy intensive would tend to increase in price more than other products, and demand for them may weaken. The effects of changes in energy prices and economic activity on energy consumption are discussed in each of the end-use sections in this chapter.

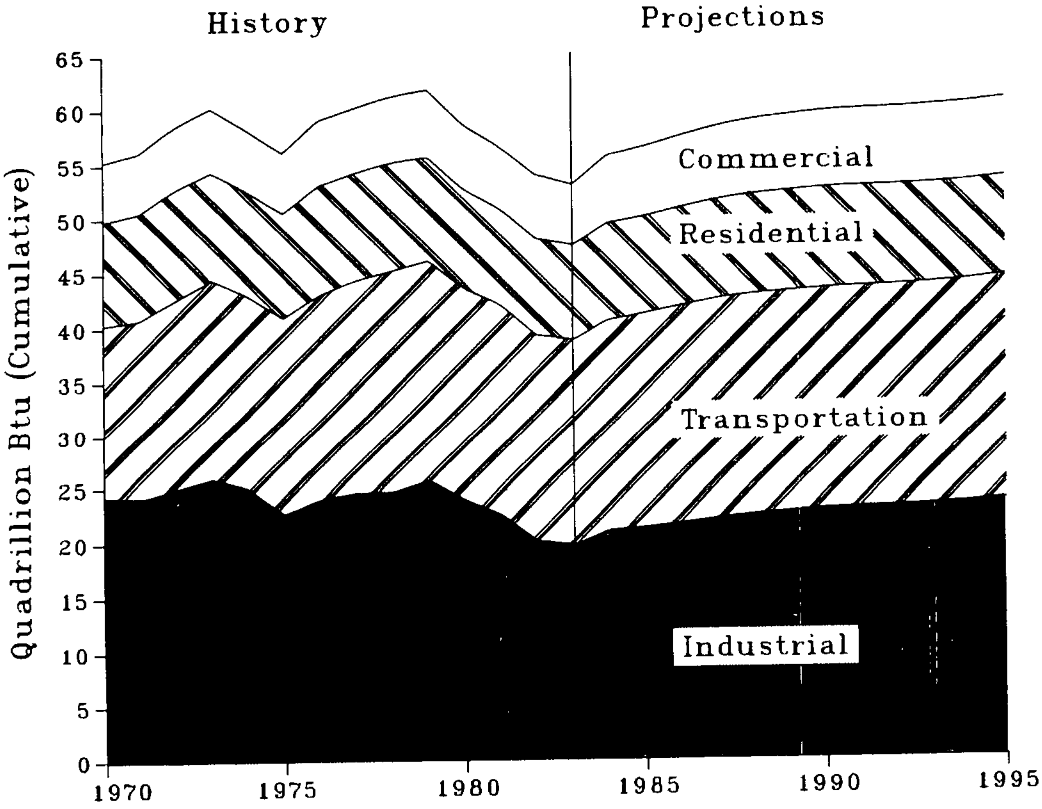
Economic growth increases consumers' ability to purchase goods and services, including energy services, and tends to increase energy demand. More rapid economic growth, however, also may serve to increase the average efficiency with which energy services are provided, as households purchase more fuel-efficient cars and industries modernize and build additional plants.

Energy efficiency increases as energy-using equipment is replaced or rebuilt to consume less energy per unit of output. To the extent that energy prices have risen more rapidly than other prices, newly acquired equipment tends to be more efficient in using energy than the average stock of energy-using equipment. The availability of more energy-efficient equipment is the result of equipment manufacturers' responses to consumer demand as well as, in some cases, legislatively mandated efficiency improvements.

Recent Trends in Total End-Use Energy Consumption

Energy consumption by end-use sector (residential, commercial, transportation, and industrial) is shown in Figure 10 and Appendix Table A4. Significant changes in end-use energy consumption have occurred since 1973. From 1973 to 1975 and from

Figure 10. End–Use Energy Consumption by Sector, Midprice Scenario, 1970 to 1995



Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

1979 to 1980, large energy price increases, as well as economic recessions, led to reduced levels of energy demand. The effects of energy prices on the economy are discussed in Chapter 7.

Between 1983 and 1995, total end-use demand for energy is projected to increase at an average rate of about 1.1 percent per year in the midprice case. In the high world oil price case, end-use energy demand is projected to increase at an average rate of about 0.7 percent per year (Table C4), while in the low world oil price case, it is projected to increase at a rate of about 1.5 percent per year (Appendix Table B4).

In adjusting to higher real energy prices, the economy has become less energy-intensive. From 1973 to 1983, total primary energy consumption per constant dollar of Gross National Product (GNP) declined at an average rate of about 2.5 percent per year. This trend is projected to continue at about half the 1973-83 rate through 1995. By 1995, total primary energy consumption per constant dollar GNP is projected to be only about two-thirds of the 1973 level. Electric utility conversion losses are included in total primary energy consumption, hence primary energy use per dollar of GNP has declined more slowly than end-use energy consumption per dollar of GNP.

Figure 11 shows trends in the types of energy consumed by the end-use sectors. End-use consumption of oil declined by about 9 percent over the last decade. Reliance on oil is projected to remain stable through 1995, accounting for a little over half of total end-use energy.

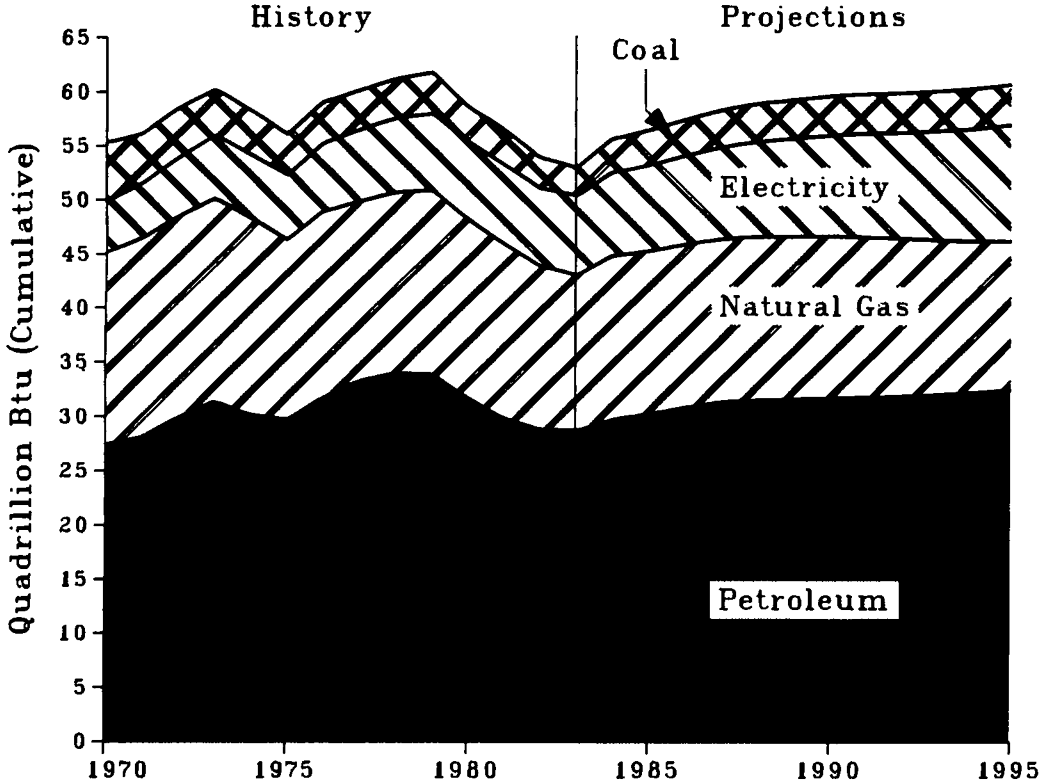
End-use reliance on electricity has increased more than any other energy source since 1973. This increase came about even though electricity was the most expensive end-use energy source and its price increased substantially. Over the forecast period, reliance on electricity is projected to continue to increase, accounting for 18 percent of end-use energy consumption by 1995 (compared with 14 percent in 1983). This increase follows the historical trend in which electricity has been a preferred energy source and is reinforced by the continued stability projected for electricity prices compared to other fuel prices.

Natural gas' share of end-use energy consumption declined slightly between 1973 and 1983. This decline in end-use reliance on natural gas is projected to continue and, by 1995, natural gas is projected to account for 23 percent of end-use energy consumption, compared with 27 percent in 1983. Natural gas prices are projected to increase significantly faster than petroleum product prices between 1983 and 1995.

The direct end-use of coal has declined recently, following output trends in the steel industry. Indirect end-use requirements for coal are increasing, however, since coal is generating a larger portion of the Nation's electricity. Electric utilities accounted for slightly over four-fifths of total domestic coal use in 1983, and this share is projected to remain stable through 1995.

The shares of total energy consumed by each sector are projected to remain fairly stable through 1995. The industrial sector's share is projected to increase slightly over the forecast period, reaching about 39 percent in 1995. The residential and transportation sectors' shares are projected to decline slightly throughout the forecast period.

Figure 11. End-Use Energy Consumption by Energy Source, Midprice Scenario, 1970 to 1995



Sources: Historical Data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

The projections of end-use energy consumption in this report are based on analyses of detailed annual, energy consumption. There is generally about a 2-year lag in the availability of these data; more aggregate data are available, however, on a more current basis. The Energy Information Administration's Short-Term Energy Outlook (STEO), which provides quarterly energy balance projections, utilizes the most recent aggregate fuel-use data. In order to reflect these data, the projections appearing in this report have been adjusted to be consistent with the February 1984 quarterly projections. Appendix D briefly describes the procedures used to develop and adjust the annual energy projections.

Overall, very little adjustment was needed. The procedures used to develop annual projections through 1995 for this report, for example, projected a 1984 electricity and natural gas total that was slightly below (1.3 and 2.4 percent, respectively) the February STEO forecasts. The annual projections for the entire projection period were adjusted upward to reflect this difference. Similarly, projections of motor gasoline were adjusted downward by about 2.3 percent.

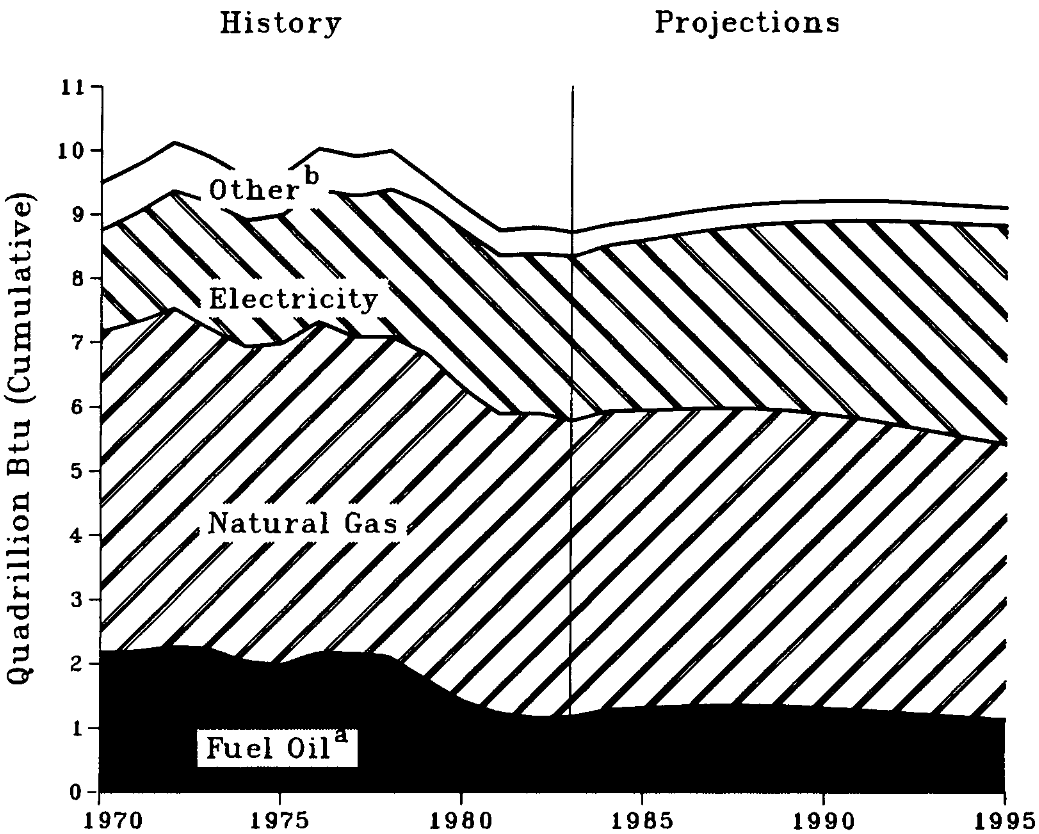
Residential Energy Demand

From 1973 to 1983, residential sector energy use declined by about 12 percent despite a substantial increase in the number of households (Figures 12 and 13, Appendix Table A4). Energy use per household declined by one-third from its highest level in 1972, largely in response to rapidly increasing energy prices. As shown in Figure 14, real prices of residential natural gas and fuel oil have increased dramatically over the last decade.

The decline in energy use per household realized since 1972 was accomplished, for the most part, by changes in the improved efficiency of appliances and structures, and by behaviorial changes. Wood consumption, which is not included in the residential sector's energy use totals, also increased over this period. It is likely that some of the measured decrease in energy consumption per house was due to the substitution of wood for one of the more conventional fuels. Since most of the housing stock that will be in use through the projection period already exists, investments in efficiency improvements that have already been made will continue to be an important factor in projections of future energy use in the residential sector.

Total residential energy consumption is expected to increase slowly between 1983 and 1995 because the projected reduction in energy use per household almost cancels out increases in the number of households. In the midprice case, residential sector demand for energy reaches about 9.1 quadrillion Btu compared to 8.8 and 9.4 quadrillion Btu in the high and low world oil price cases, respectively. The major cause for the projected decrease in energy use per household continues to be the forecast increase in real fuel prices (Figure 14). Residential distillate fuel oil prices are projected to grow at an average annual rate of about 3.7 percent between 1983 and 1995, while natural gas prices are projected to increase at an annual rate of 5.2 percent over this period. Electricity prices, in contrast, are projected to increase at an annual rate of only about 0.5 percent

Figure 12. Residential Fuel Consumption, Midprice Scenario, 1970 to 1995

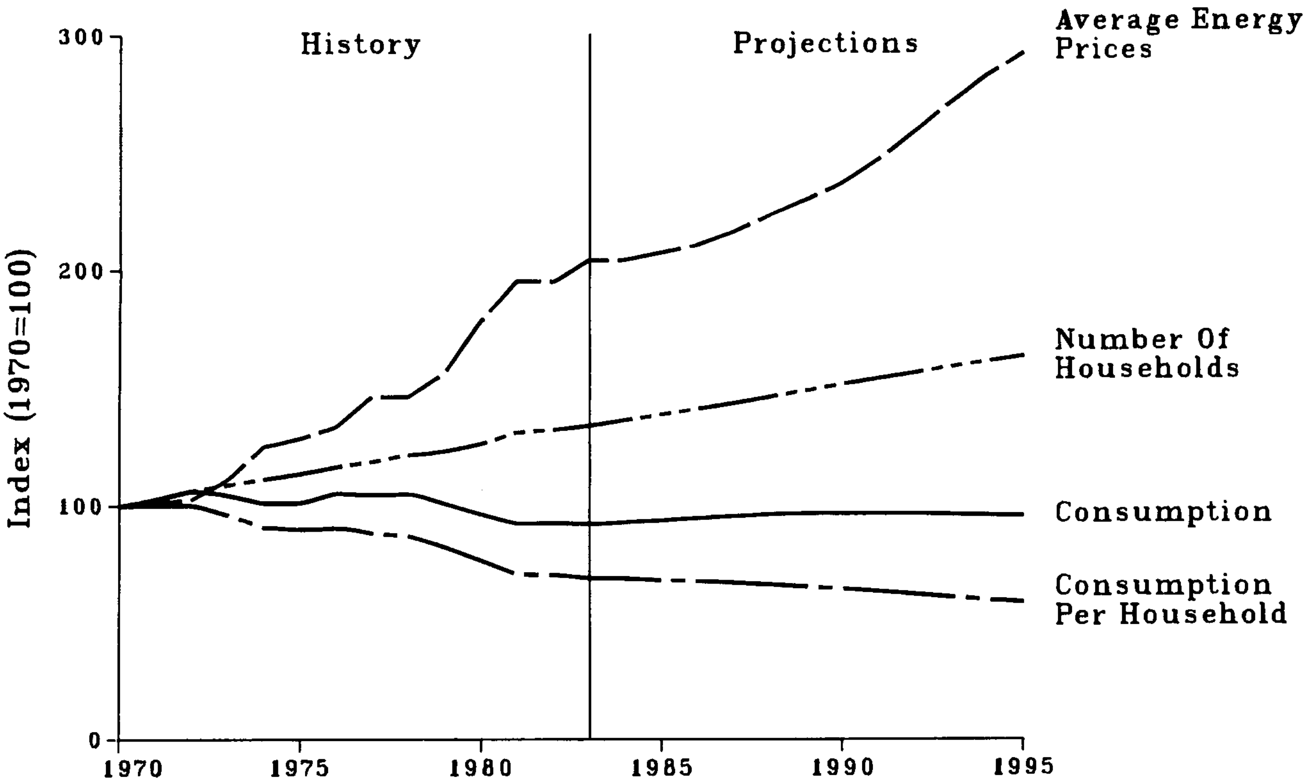


[a]Fuel oil includes distillate oil and kerosene.
[b]Other includes liquid gas and coal.

Note: Residential consumption of wood is not included.

Source: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983).

Figure 13. Indexes of Residential Energy Use, Midprice Scenario, 1970 to 1995

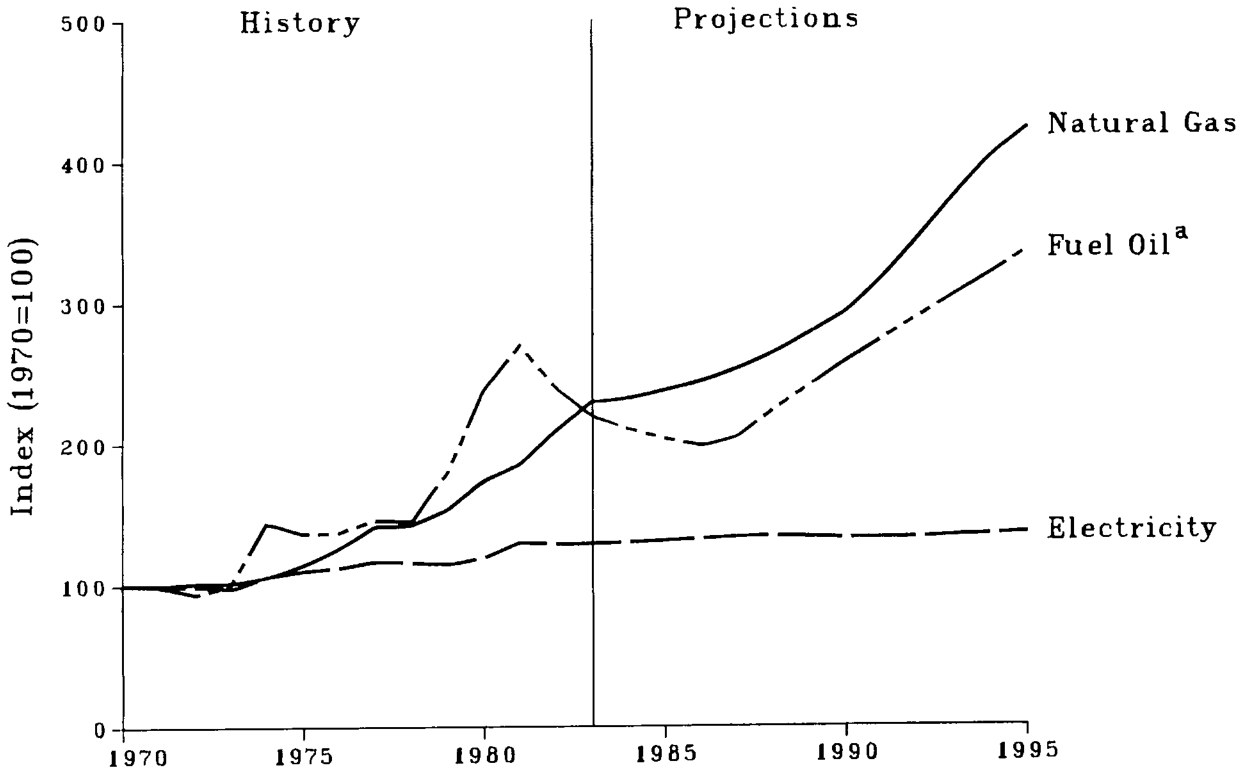


Note: Residential consumption of wood is not included.

Sources: Historical data: Consumption from: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983).

Prices from: Energy Information Administration, Energy Price and Expenditure Data Report, 1970-1980, DOE/EIA-0376 (Washington, D.C., 1983); Households from U.S. Department of Commerce, Bureau of the Census, Current Population Report, (Washington, D.C.) various issues.

Figure 14. Indexes of Residential Energy Prices, Midprice Scenario, 1970 to 1995



[a]Fuel oil includes distillate oil and kerosene.

Source: Historical data: Energy Information Administration, Energy Price and Expenditure Data Report, 1970-1980, DOE/EIA-0376 (Washington, D.C., 1983).

from 1983 to 1995. Following world oil price projections, distillate fuel oil prices are projected to remain below their 1983 level until 1988 and then increase significantly between 1988 and 1995.

Energy use in the residential sector consists of heating and nonheating uses. Heating uses, which include home space and water heating, are characterized by their relationship to the stock, location, and size of houses, by their potential for improved efficiency in use, and by their fuel substitution possibilities. Nonheating uses, such as air conditioning and lighting, are less dependent on these factors. Natural gas is projected to continue as the dominant fuel for heating purposes, while electricity is expected to continue as the major energy source for nonheating energy requirements.

Heating Uses

Over seven-tenths of residential energy consumption in 1983 is estimated to be used for heating purposes.[2] Space heating is projected to continue to account for most of this share. Over the forecast period, however, the share of residential energy consumed for space heating purposes is projected to decline slightly, while that for heating water remains about the same.

Natural gas is the major fuel consumed in the residential sector because it has been the fuel of choice for space heating in areas where it has been available (Figure 12). In 1983, natural gas accounted for slightly over one-half of total residential energy use. About two-thirds of total residential natural gas consumption was used for heating homes and almost one-fourth of natural gas consumption was used for heating water.

As shown in Figure 12, total residential energy use is projected to increase slightly over the forecast period. Natural gas use, however, is projected to decrease due to a projected decline in heating uses relative to nonheating uses and an erosion of the natural gas price advantage. Although natural gas remains the lowest priced fuel, its price is projected to increase considerably faster than the price of oil or electricity between 1983 and 1995, both in absolute and percentage terms (Figure 14). These projected changes in relative prices lead to changes in consumer conservation behavior, increased structure and equipment efficiency, and substitution of other fuels. Electricity's share of residential space heating is projected to increase from about 5 percent in 1983 to about 11 percent by 1995.

Residential heating oil consumption (distillate plus kerosene) accounted for almost 14 percent of total residential energy use in 1983. Oil was used almost exclusively for heating purposes in 1983. By 1995, residential sector oil consumption is projected to be about one-half of its peak level of 2.3 quadrillion Btu reached in 1972.

Other Uses

Nonheating uses such as air conditioning, lighting, refrigeration, and various other mostly electricity-using services accounted for about three-tenths of residential energy consumption in 1983. Electricity consumption is second to natural gas in the residential sector, although it is not used extensively for heating homes. In 1983, almost four-fifths of total energy used for nonheating purposes was electricity. As shown in Figure 12, residential electricity consumption was about 2.6 quadrillion Btu in 1983, about three-tenths of total residential energy use. While total residential energy consumption is projected to increase only slightly, electricity consumption is projected to increase at an average annual rate of about 2.4 percent from 1983 to 1995.

This projected increase in electricity use is largely due to the dominant role of electricity in providing nonheating services. Such services, following long-term trends, are projected to be increasingly used in both new and existing housing. Also, since electricity accounts for only a small fraction of space and water heating services, widespread conservation in these uses has little impact on electricity consumption. The projected small increase in the price of electricity does not significantly constrain electricity consumption, although the projected rate of increase in electricity use is lower than that realized over the last decade. From 1980 to 1983, the growth of residential electricity consumption slowed considerably. During this period, the recession slowed residential construction, and electricity prices experienced uncharacteristically large increases. Both of these influences are expected to return to more traditional trends, and the projected trends in electricity consumption follow suit.

Overall Use

Energy in the residential sector is projected to continue to be used less for heating and more for nonheating purposes. Rapidly increasing prices for fuel oil over the last decade and for natural gas over the last few years have led consumers not only to use these fuels more efficiently, but also to shift away from these traditional heating fuels. The share of new homes installing electric space heating has increased from less than one-third in 1971 to over one-half by 1978. This share has remained relatively stable at about one-half for the last several years.

The slow shift in residential energy use from heating uses to nonheating uses is due to more than prices alone. Households have been moving from colder climates to warmer climates, and this trend is expected to continue. Although only slightly more than one-half of the Nation's housing stock in 1982 was located in the South and the West Census Regions, almost three-fourths of all new housing construction was in those two regions.[3] As expected, households in warmer climates consume less energy for heating uses, and have lower total energy requirements. For example, in 1983, the estimated average energy use per household (in all uses) was 119 million Btu in the Northeast Census region, 131 million Btu in the North Central, 80 million Btu in the South, and 87 million Btu in the West. A larger proportion of households in warmer climates have tended to rely on electricity for heating purposes. In the South, for example, about 63 percent of new homes built in 1982 installed electricity-using equipment for space heating, compared to 50 percent for the Nation.

Several other factors also help explain the decrease in residential energy use and the shift from heating to nonheating uses. Multifamily housing, which requires less heating per unit, has been increasing its share relative to the single-family housing stock. More than two-thirds of the housing stock in 1982 consisted of single-family homes. Only a little more than one-half of all new construction in 1982, however, consisted of single-family homes. In addition, the size of new houses has not continued to increase as it had in the past, and has even decreased slightly in recent years.

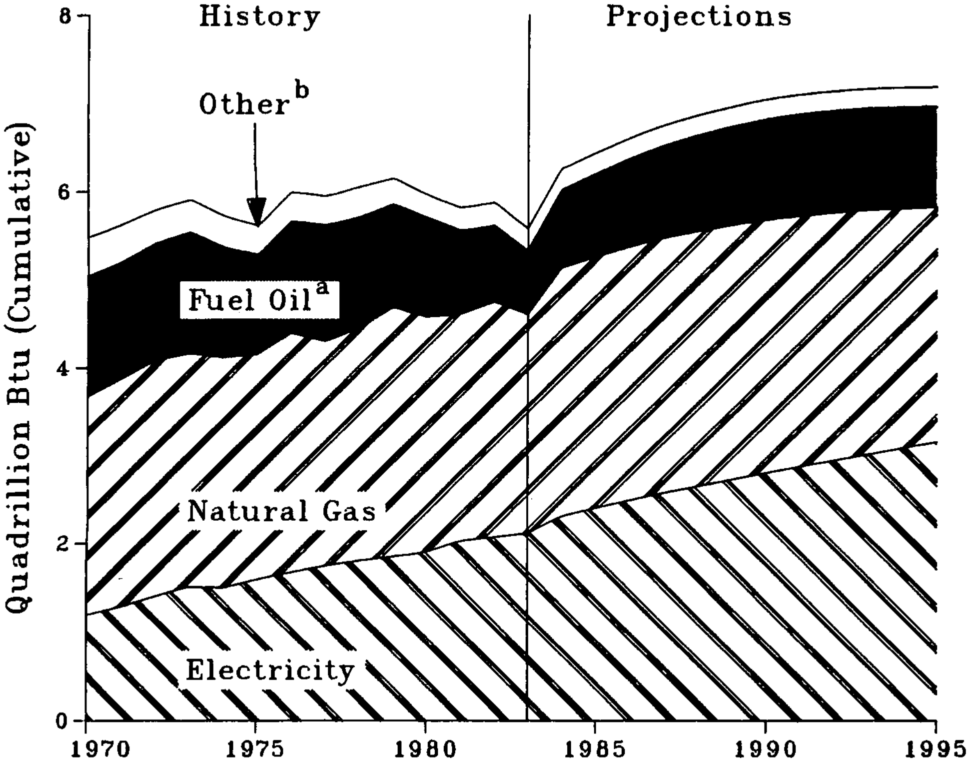
Commercial Energy Demand

The commercial sector, consisting of a diverse group of buildings ranging from warehouses to hospitals, consumed slightly over 10 percent of total end-use energy in 1983. About three-fifths of commercial energy consumption was estimated to have been used in office and retail/wholesale buildings in 1983.[4] The major use of energy in the commercial sector is for space heating, although this varies with the type of building.

Commercial building floorspace has grown rapidly over the last decade. This trend reflects the increasing service orientation of the economy. As shown in Figure 15 and in Appendix Table A4, total commercial energy use is projected to increase by about 29 percent from 1983 to 1995 in the midprice case (compared to about 23 percent in the high world oil price case and 34 percent in the low world oil price case). During the same period, commercial energy use per square foot is projected to decline while electricity replaces natural gas as the primary energy source. As is the case for the residential sector, the stock of buildings already in existence has a large impact on energy use through the projection period.

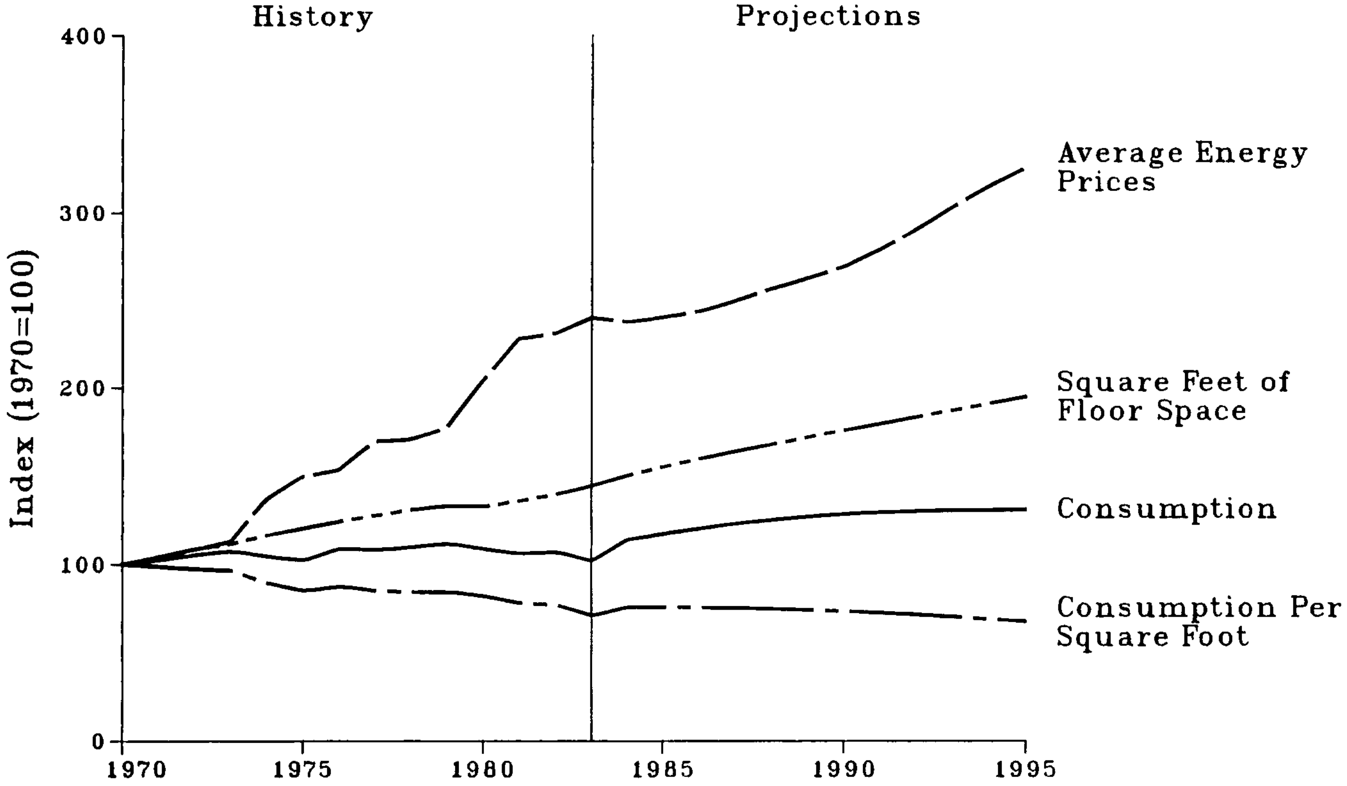
Commercial building floorspace and energy prices are the two major factors influencing commercial energy consumption. Growth in total energy consumption is strongly related to the growth in commercial floorspace. Commercial floorspace is projected to increase by about 35 percent from 1983 to 1995 due to the projected growth in population and the general expansion of the economy. Growth in energy due to changes in floorspace, however, is dampened by this sector's continuing response to higher energy prices. Energy use per square foot is forecast to decrease over this period (Figure 16).

Figure 15. Commercial Energy Use by Fuel, Midprice Scenario, 1970 to 1995



[a]Fuel oil includes distillate oil, residual oil, and kerosene.
[b]Other includes liquid gas, coal, and motor gasoline.
Source: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983).

Figure 16. Indexes of Commercial Energy Use, Midprice Scenario, 1970 to 1995



Sources: Historical data: Consumption from: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983). Prices from: Energy Information Administration, Energy Price and Expenditure Data Report, 1970-1980, DOE/EIA-0376 (Washington, D.C., 1983). Floorspace from estimates made in support of the Commercial Sector Energy Model.

Increased Reliance on Electricity

Electricity is forecast to meet nearly 44 percent of the commercial sector's energy requirements by 1995 compared to 38 percent in 1983 (Figure 15 and Appendix Table A4). This forecast shift toward electricity use is due to electricity's projected increasingly attractive relative price. This forecast takes into account both different regional rates of growth of commercial floorspace, and growth of floorspace by type of building.

Commercial energy consumption decreased slightly from 1973 to 1983. Since the square feet of floorspace continued to increase, energy use per square foot decreased strongly. Energy use per square foot is projected to continue to decrease between 1983 and 1995 to a level of 109 thousand Btu per square foot in 1995. These projected improvements follow recent trends in new building construction, retrofit efficiency improvements, and consumer behavior.

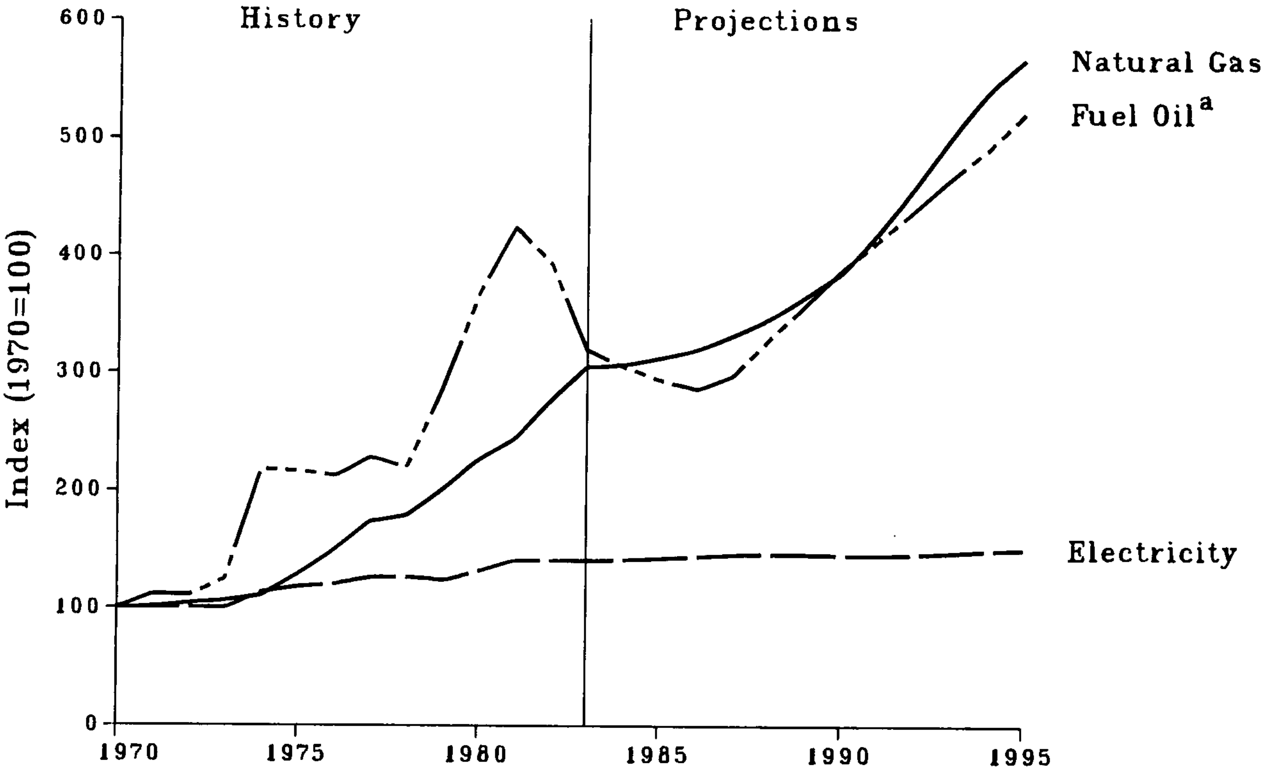
Efficiency improvements are projected to continue to be sensitive to fuel prices. As shown in Figure 17, natural gas prices are projected to increase more than prices of other fuels. The projected decrease in natural gas consumption resulting from price increases approximately balances the increase in natural gas consumption due to increases in floorspace. The net effect is that natural gas use is projected to remain relatively steady to 1995. Electricity prices, in contrast, are projected to increase relatively little so, in consequence, electricity consumption increases with floorspace growth.

Historically, the commercial sectors in the South and West Census Regions have relied more heavily on electricity than those of the North and East Census Regions. Over the forecast period, commercial building floorspace in the South and West Census Regions is projected to grow at about twice the rate of increase projected for the rest of the country. As a result, total commercial reliance on electricity is projected to increase.

The projected growth of commercial floorspace by type of building also helps explain the strong performance of electricity. From 1983 to 1995, roughly seven-tenths of all floorspace growth is projected to occur in the office and retail/wholesale categories. These building types consume electricity somewhat more intensively than the other building types, and as a result there is a projected increase in the utilization of electricity for the entire commercial sector.

The reasons for continued increasing reliance on electricity parallel those discussed for the residential sector. Electricity prices, though they remain higher, are projected to increase less rapidly than the prices of other fuels. Natural gas and fuel oil are used primarily for space heating, which is projected to account for a declining portion of commercial energy use. During the projection period, electricity replaces natural gas as the major fuel consumed in the commercial sector.

Figure 17. Indexes of Commercial Energy Prices, Midprice Scenario, 1970 to 1995



[a]Fuel Oil includes distillate oil, residual oil, and kerosene.

Source: Historical data: Energy Information Administration, Energy Price and Expenditure Data Report, 1970-1980, DOE/EIA-0376 (Washington D.C., 1983).

EIA Energy Consumption Surveys

In the late 1970's, the EIA initiated two national surveys in the residential and commercial sectors of the Nation's economy. The surveys, the Residential Energy Consumption Survey (RECS) and the Nonresidential Buildings Energy Consumption Survey, continue to provide a wealth of information used to assist the private sector and all levels of government in making crucial decisions related to energy use.

The first Residential Energy Consumption Survey (National Interim Energy Consumption Survey) was conducted in 1978 using a representative sample of 4,500 households across the United States. Personal interviews covered such topics as: energy-related structural features of the housing unit, type of heating and cooling systems and fuels used, type of household appliances and vehicles, demographic data on household members, and energy conservation efforts.

In order to obtain improved estimates of total consumption data for the residential sector, a RECS Household Transportation Panel was initiated in 1979. Information was collected monthly and included such topics as miles-per-gallon, cost of fuel, and average number of vehicle-miles traveled.

While the size of the residential survey varied during the next 4 years, it was notably improved by the addition of questions on unique data items such as thermostat settings for indoor temperatures, the use of air conditioning equipment, consumption of wood fuel, and the extent and use of secondary heating equipment, as well as the availability and use of energy audits and energy assistance programs. The results of the most recent survey are available in Residential Energy Consumption Survey: Consumption and Expenditures - April 1981 Through March 1982 - Part 1: National Data, September 1983, DOE/EIA-0321/1(81), and Part 2: Regional Data, DOE/EIA-0321/2(81).

The Nonresidential Buildings Energy Consumption Survey was initiated in 1979 using a representative sample of approximately 6,200 nonresidential buildings across the United States. Data on actual energy consumption were collected from fuel records maintained by the building's fuel suppliers.

This 1979 survey was the first time that data on the characteristics of the stock of nonresidential buildings in the United States was collected. The data include statistics on structural features (such as square footage and number of floors), use and occupancy characteristics (such as number of employees working in building), types of fuels used, types of heating and cooling systems, energy efficiency measures (such as addition of insulation, caulking, weatherstripping, treated glass, and outside shading), and conservation practices used (such as reduction in heating and cooling, and regular maintenance). The latest

issue of this survey is Nonresidential Buildings Energy Consumption Survey: 1979 Consumption and Expenditures, Part 2: Steam, Coal, Fuel Oil, LPG, and Total Fuels, DOE/EIA-0318/2.

The design of an energy consumption survey for the manufacturing sector is currently under consideration. Information on industrial energy use is now very limited.

Energy Supplies from Wood

Wood is largely a nonmarketed fuel and as a result reliable estimates of consumption are difficult to make. Total wood energy consumption is estimated to have been slightly over 2.2 quadrillion Btu in 1981. The use of wood as a source of energy has increased by an estimated 56 percent from 1971, when approximately 1.4 quadrillion Btu were consumed.

In 1981, the vast majority of wood was consumed in the residential and industrial sectors. In that year, the residential sector used an estimated 0.8 quadrillion Btu of wood energy. Industrial consumption was an estimated 1.4 quadrillion Btu of wood energy, almost entirely in the form of wood wastes at paper and wood products facilities. These estimates are contained in Estimates of U.S. Wood Energy Consumption from 1949 to 1981, DOE/EIA-0341.

With the exception of a small amount of wood consumed for fuel by electric utilities, wood is not included explicitly in the energy flows shown in this report. It does, however, displace other fuels that are covered in the end-use consumption estimates.

Industrial Energy Demand

The industrial sector is the largest end-use consumer of energy in the economy, using energy both for heat and power and as a raw material. This sector accounted for about 37 percent of the energy consumed by end-use sectors in 1983. It accounted for over three-quarters of end-use oil consumption outside of the transportation sector, though its use of petroleum in 1983 was about 15 percent less than the level reached in 1973. The industrial sector's energy needs are very sensitive to the general state of the economy and, in particular, to activity in the highly cyclical energy intensive industries. Figures 18 and 19 and Appendix Table A8 show historical and projected trends in industrial sector fuel use. Total industrial energy consumption is projected to grow at about 2.3 percent per year between 1983 and 1990 and at 0.68 percent per year from 1990 to 1995 in the midprice case. In contrast, in the high and low world oil price cases, industrial energy consumption is projected to grow at about 2.0 and 2.5 percent, respectively, between 1983 and 1990 and at about 0.4 and 1.0 percent, respectively, between 1990 and 1995.

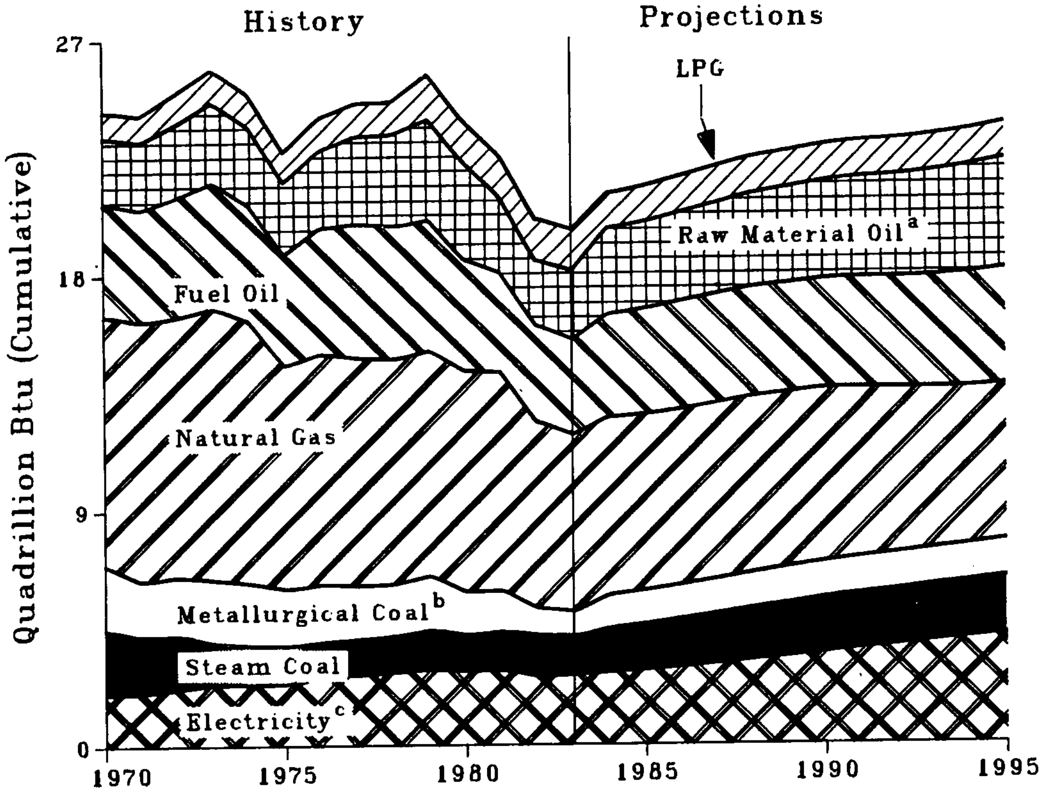
The decline in energy use per unit of industrial output, as shown in Figure 19, has mirrored general improvements in productivity and changes in product mix since 1974. During the rapid energy price increases of the 1970's, the energy use per unit of output in specific manufacturing industries declined on the average at about the same rate as labor, materials, and capital use per unit of output declined. Energy use per unit of output is projected to continue to decline through 1995 because of continuing energy price increases and the replacement of equipment bought before past energy price increases. Increases in energy prices have had little immediate effect on industrial energy consumption when specific industries are studied. They have had a substantial lagged effect, however, which affects the energy intensity of industrial output at about the same rate that old equipment depreciates (10 percent per year).[5]

The industrial sector has a greater near-term potential to switch from one fuel to another than the other end-use sectors. Fuel shares are projected to differ markedly from the recent past. Electricity use is projected to increase at a rate of 4.1 percent per year from 1983 to 1990, slightly slower than the index of manufacturing output. Electricity use accounts for nearly 18 percent of the industrial sector's energy requirements by 1995 compared to about 14 percent in 1983. Factors contributing to the projected increase in industrial reliance on electricity include projections of improved economic conditions (particularly in the steel industry), as well as growth in electricity use for mining and irrigation. Recent and projected trends in industrial reliance on electricity are discussed more fully below. The projections here suggest a more rapid growth in electricity than many expect; however, detailed technology-based projections[6] and policy studies by Department of Energy[7] also have projected rapid growth.

Total oil demand is projected to grow in response to stable oil prices and an improving economy. Projected industrial oil use in 1990, however, remains below the level reached in 1978 (but above the 1983 level). By 1995, total industrial oil demand is projected to be about 28 percent higher than the estimated 1983 level.

Natural gas use is projected to remain virtually unchanged through 1995, as economic growth cancels out the effects of conservation and shifts towards other fuels. Industrial coal consumption is projected to reverse the downward trend experienced since before 1970. These forecasts are all conditional on an assumption of rapid growth in highly cyclical industries; this assumption is highly uncertain and is discussed further in Chapter 7.

Figure 18. Industrial Energy Use by Fuel, Midprice Scenario, 1970 to 1995



[a]Raw Material Oil consists of petrochemical feedstocks, special naphthas, lubricants and waxes, asphalt, and other raw material oils as shown in Appendix Table A8.

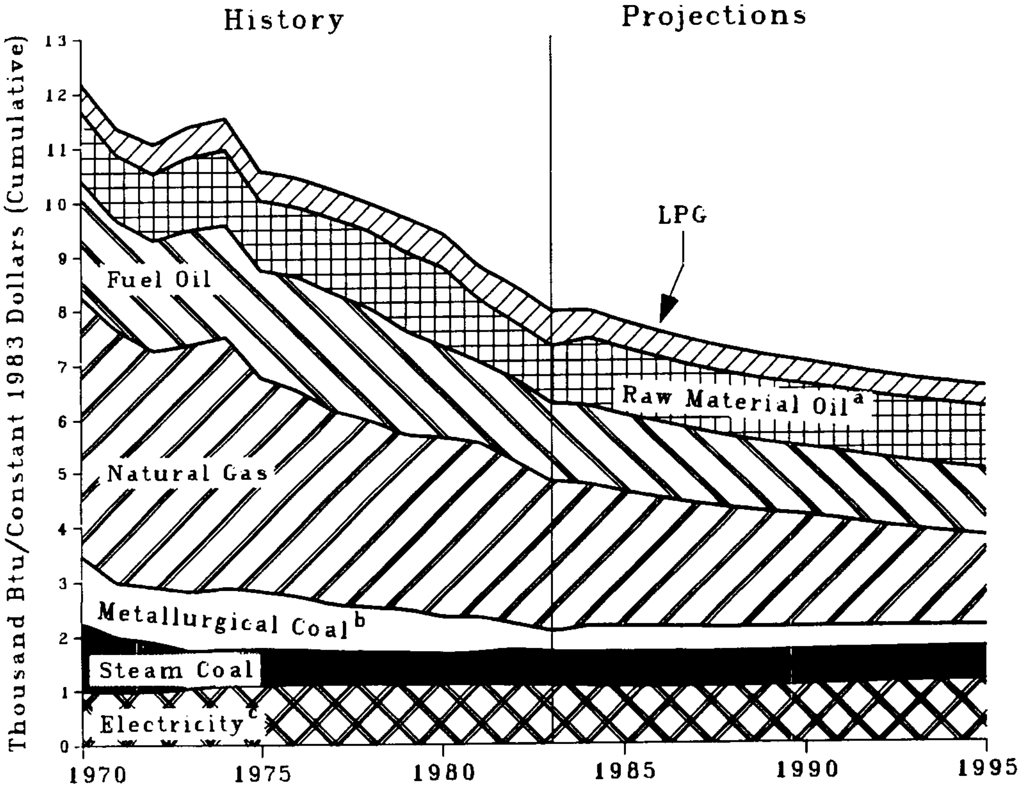
[b]Metallurgical Coal includes net imports of coal based coke.

[c]Electricity includes hydropower but not self-generated electricity based on consuming other fuels.

Note: Energy Use for all fuels includes refinery fuel use.

Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

Figure 19. Energy Use per Unit of Industrial Output, Midprice Scenario, 1970 to 1995



[a]Raw Material Oil consists of petrochemical feedstocks, special naphthas, lubricants and waxes, asphalt and other raw material oils as shown in Appendix Table A8.

[b]Metallurgical Coal includes net imports of coal based coke.

[c]Electricity includes hydropower but not self-generated electricity based on consuming other fuels.

Note: Industrial output is significantly larger than industrial value-added. Projections of industrial energy use in this report are based on analysis of industrial energy use per unit of gross output in specific industries (see footnote 8, Chapter 4).

Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Industrial Output from Data Resources Inc., Input--Output database (agriculture plus construction plus mining plus manufacturing).

Analysis

The industrial sector includes manufacturing, agriculture, mining, and construction. Data in the Annual Survey of Manufactures indicate that the manufacturing sector consumed about 85 percent of total industrial energy in 1981.

Most of the manufacturing sector's energy consumption is concentrated in five industry groups: Chemicals and Rubber (Standard Industrial Codes (SIC) 28 and 30); Primary Metal Industries (SIC 33); Paper and Allied Products (SIC 26); Stone, Clay, and Glass Products (SIC 32); and Food and Kindred Products (SIC 20). In 1981, these industries consumed about 80.1 percent of the total manufacturing sector's purchased energy for heat and power (excluding refineries) and almost all the energy used as raw materials in manufacturing. Energy is used in manufacturing mainly to make large scale chemical transformations from raw materials to more organized matter such as petrochemicals, plastics, steel, aluminum, cement, and glass. Each of these products is very energy-intensive and substantial reductions in industrial energy use in the long term may require less production of goods which require these products as inputs such as heavy machinery, large cars, and buildings.

Aggregate industrial energy use depends on energy use per unit of aggregate output and the aggregate output of the industrial sector. Aggregate industrial energy use per unit of output depends on the mix of products (energy intensive versus nonenergy-intensive products) and the amount of energy used to produce each product. Both of these factors are critical in determining aggregate industrial energy use per unit of output. For example, one important reason for the large decrease in industrial energy use in the 1982 recession was a shift in the output product mix from energy-intensive products to less energy-intensive products. During the 1982 recession, the steel and basic chemical industries, the two largest industrial energy users, were more severely affected than the rest of the economy including other industries. These industries are highly cyclical. Nevertheless, they did poorly in the 1982 recession even compared to previous recessions. In general, in the 1982 recession, the energy-intensive industries were more severely affected than suggested by the decrease in GNP or the decrease in the overall index of production for manufacturing industries.

High real interest rates and foreign trade competition have been cited as reasons for the relative decline in basic industries such as steel in the recent past. These two factors are not completely independent because high interest rates in the United States lead to a high dollar exchange rate. This makes foreign goods relatively less expensive in the United States and encourages foreign imports.

Low growth in the U.S. economy has led to far less capital investment--structures and equipment--than would otherwise have been the case. In an expanding economy, energy-intensive capital investment grows at a faster rate than the rest of the economy. Hence, changes in the rate at which the economy grows plays a very important role in determining the level of industrial energy use. If the rate of growth of GNP shifts from 2 percent to 4 percent per year, this would double certain components of industrial energy consumption. The economic recovery assumed in these projections translates directly into higher demand for the relatively energy-intensive products.

The amount of energy used to produce a product changes as a result of general improvements in productivity (reduction in all production costs per unit of output) as well as energy conservation. Analyses of the available data indicate that the reduction in energy intensity within industries occurring between 1974 and 1981 was about equal to general improvements in productivity.

From 1958 to 1974, firms tended to use increasing amounts of energy relative to labor because it helped reduce labor and other production costs. Since 1974, the data show a trend toward substitution away from energy when new plants and equipment are put into service, reflecting higher energy costs. This trend has cancelled out the trend towards more use of energy relative to labor and is projected to continue as long as energy prices continue to rise relative to the prices of other inputs to production.

The use of each fuel in each industry is the product of four separate factors: (1) the fuel's share of energy use (fuel/energy); (2) energy use per unit of output (energy/output); (3) industry's share of real GNP (industry's output/real GNP); and (4) the level of real GNP. Together, these factors help explain the past and projected use of particular industrial fuels. The following sections discuss the demand outlook for individual industrial fuels.

Electricity

Table 15 provides a breakdown of the changes that have accompanied electricity and oil consumption in manufacturing in the recent past.[9]

Table 15. Factors Affecting Industrial Electricity and Oil Consumption, 1974 to 1981, for Heat and Power in Manufacturing (Percent)

	Electricity		Oil	
	1974 to 1981	1979 to 1981	1974 to 1981	1979 to 1981
Total Change In Fuel Use	+7.2	-2.1	-44.8	-39.7
Due to Fuel Choice Changes	+15.9	+8.0	-38.6	-32.1
Due to Energy Intensity Changes	-11.5	-5.4	-9.3	-5.1
Due to Output Mix Changes	-16.5	-6.2	-10.9	-3.7
Due to Real GNP Changes	+19.4	+1.5	+14.0	+1.2

Source: Energy Information Administration, A Statistical Analysis of What Drives Industrial Energy Demand, DOE/EIA-0420/3 (Washington, D.C. 1983).

From 1974 to 1981, electricity use in manufacturing increased by 7.2 percent. This increase was realized despite a trend toward reduced energy intensity and output mix changes that tended to reduce electricity demand. Electricity use is projected to grow at an average annual rate of 4.1 percent from 1983 to 1990 and 3.6 percent from 1990 to 1995. This is slightly less than the 4.8 percent growth rate assumed for total manufacturing output (Appendix Table A19). As shown in Appendix Table A8, industrial electricity use is projected to increase by nearly 1 quadrillion Btu by 1990. Almost 40 percent of this increase is in primary metals (mostly steel), and 23 percent is outside of manufacturing (mainly mining and irrigation).

As in recent years, the general trend toward less energy use per unit of output is projected to cancel out the trend towards greater relative reliance on electricity. However, the output mix projections upon which these forecasts are based depart from the recent past and favor increased use of electricity. As GNP growth rises, and real interest rates fall, a recovery is projected in the energy-intensive industries. The turn-around is greatest in the primary metals industry, where real output is projected to increase by 49 percent from its low point in 1982 to 1990. A gradual increase in the share of electricity in primary metal manufacturing is projected as electric arc furnaces and small reprocessing steel mills continue to increase their share of output. The projections for nonmanufacturing electricity use are somewhat conservative because the available data are fragmentary, and extrapolation of the rapid growth that they suggest is risky. It is assumed that gas and electricity use in mining will increase only in proportion to output. Possible increases in the share of oil and gas production from deep oil and gas wells or stripper wells are not incorporated in the projections of electricity use. Similarly, all irrigation is projected to grow at the historical rate for on-farm irrigation. Historically, electricity has grown much faster in these sectors.[10]

There remains substantial uncertainty about the amount of electricity that will be required by the industrial sector through 1995. These projections represent what might happen to industrial energy consumption if the energy use trends experienced over the last decade continue and if the U.S. economy recovers as quickly and as permanently as projected. Certainly, alternative scenarios concerning the nature of the economic recovery would result in different electricity use projections.

Oil and Natural Gas

As shown in Table 15, the reduction in industrial oil use from 1974 to 1981 can be explained almost entirely by changes in fuel choice. Natural gas has been oil's prime competitor, and competition between oil and gas for the heat and power market is projected to continue to be very sharp because dual-fired capacity is prevalent throughout manufacturing.[11] Projections of oil and natural gas' share of this market are assumed to vary from year to year solely on these fuels' relative prices. Total use of oil and natural gas is projected to decline in manufacturing, as trends towards less energy intensity and greater reliance on electricity continue.

Figure 20 shows the projected historial consumption of distillate oil by consuming sector. Use of distillate oil in manufacturing has declined significantly since 1974 as a result of distillate oil's high price relative to the price of natural gas. As shown in Figure 20, drill rigs, construction vehicles, and agricultural vehicles dominate the projections for this product.

Total industrial oil use grows despite the increase in oil prices because of the importance of oil use outside of heat and power applications in manufacturing. Heat and power applications in manufacturing accounted for only one-eighth of the petroleum consumed in industry in 1981.

Industrial natural gas and oil consumption vary very little between the high world oil price case and the midprice case shown in Appendix Tables A8 and C8. The share of residual oil, in the oil and natural gas total in manufacturing, is about 10 percent higher in the midprice case in 1990, because the price of residual oil is about 10 percent lower relative to natural gas. This effect is cancelled out by the greater oil and natural gas total in the midprice case, due to lower energy prices, and a rise in the output of basic industries. Other oil uses in industry compete little, if at all, with natural gas.

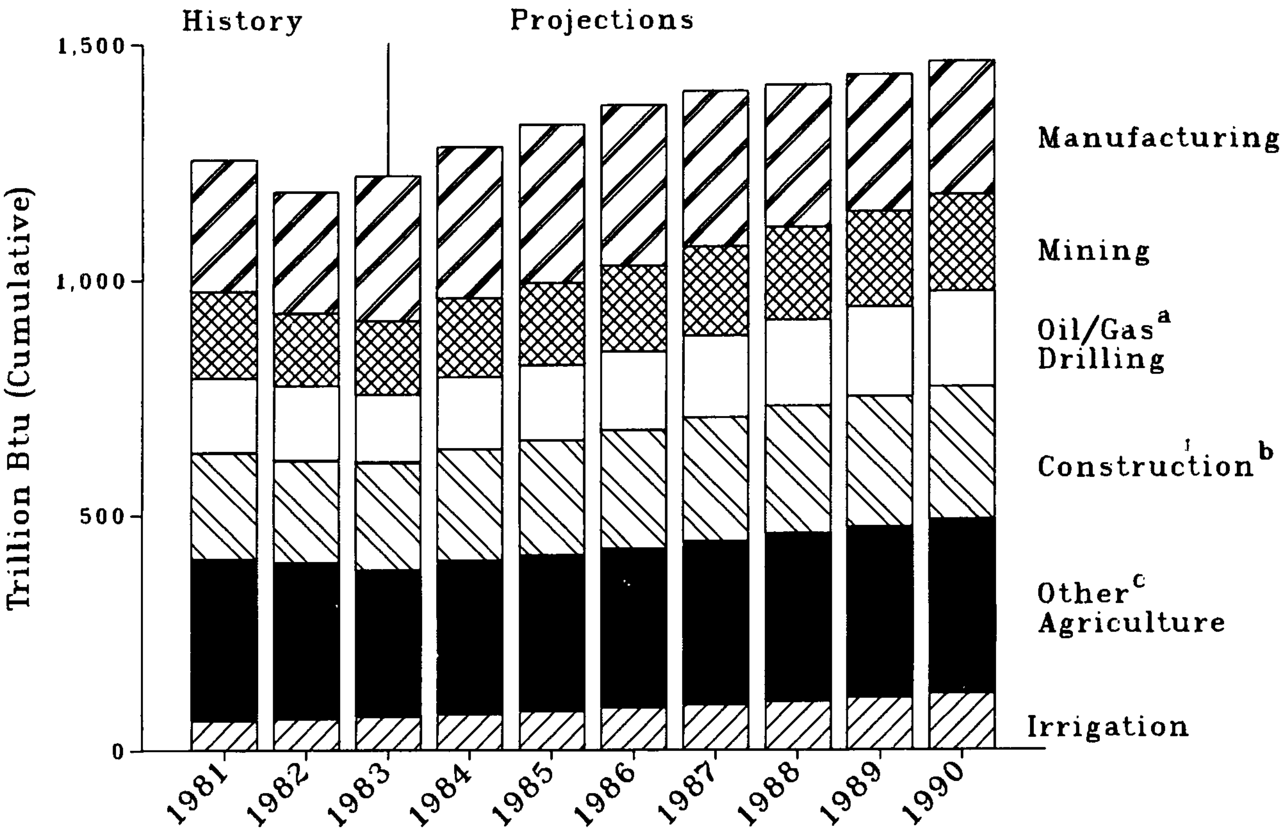
Oil and natural gas used to produce petrochemicals are very sensitive to the trade balance in petrochemicals. In order to avoid wasting natural gas, Middle Eastern nations have begun a large buildup of petrochemical capacity, which has already cut into U.S. exports and could lead to more imports in this area. This will reduce the direct consumption of oil but will increase U.S. dependence on OPEC. Projections of petrochemical feedstocks are based on a projected 39 percent increase in the output of basic organic chemicals from 1983 to 1990.

The residual fuel oil and natural gas projections assume, following historical trends, that a 1-percent decrease in the price of residual oil relative to natural gas leads to about a 1-percent increase in residual oil sales relative to gas sales for heat and power use in manufacturing. This assumption, coupled with actual fuel price changes between 1982 and 1983, would have increased residual use by about 0.3 quadrillion Btu in 1983. This estimate is consistent with recent American Gas Association surveys.[12]

In fact, total deliveries of residual oil dropped by about 20 percent from 1982 to 1983. How much of this drop occurred in the industrial sector is unknown, since the EIA survey, which disaggregates residual oil use into sectors was not carried out for 1983, and the fuel use section of the Annual Survey of Manufactures has been discontinued. The residual oil projections presented in this report have been reduced to match the recent data on total residual oil deliveries.

There remains considerable uncertainty in projecting industrial fuel-switching between residual fuel oil and natural gas. If industrial residual fuel use has declined as a result of old oil-based plants being closed during the recent economic recession, for example, then fuel-switching may still follow the historical pattern after 1983--assuming no new major economic recessions occur.

Figure 20. Industrial Consumption of Distillate Oil, 1981 to 1990



[a]Oil company use outside of refineries believed to be mainly drill rig fuel.
[b]Off-highway vehicle use outside of farms, manufacturing, and mining, i.e. bulldozers, cement trucks.
[c]Farm use other than irrigation, mainly for tractors, combines, and similar agriculture vehicles.
Sources: Historical data: Energy Information Administration, Petroleum Supply Annual, DOE/EIA-0340(82)/1/2 (Washington, D.C., 1983); U.S. Department of Commerce, Bureau of the Census, 1977 Census of Mineral Industries; U.S. Department of Agriculture Energy and U.S. Agriculture (USDA Agriculture Economic Report No. 495).

Coal

Coal consumption (in heat and power uses) is projected to grow more rapidly than than the use of any other fossil fuel, even after recovery in 1984 from the recession. Nevertheless, these coal use projections are considerably below those projections made in the late 1970's. Typically, earlier forecasts were based upon engineering models which produced projections of very rapid growth in the use of coal as a boiler fuel. The projections in Appendix Table A4 are based on statistical analyses of the historical growth of coal use through 1981. This growth has been slowed down by many barriers beyond the high cost of coal-fired boilers. However, coal remains considerably cheaper than oil or gas as a fuel for boilers throughout the projection period.

Coking coal use is projected to increase very slowly in the future, despite the large assumed increase in steel output. The difference reflects increased use of electric-arc furnaces and other trends in the use of technology.

Other Fuels

Projected levels of liquid petroleum gas use are highly uncertain due to limited data. "Other fuels" purchased for heat and power in manufacturing accounted for about $1.5 billion out of a $55 billion total in 1981. Motor gasoline (shown in[13] Appendix Table A4) and purchased steam account for most of this $1.5 billion.

Secondary fuels, such as domestically produced coke, are not added to the total because the total already includes the metallurgical coal from which the coke is produced. Most wood consumed by industry is recycled wood byproducts, that have been used by the paper industry for many years. Such recycling has led to less use of purchased energy per unit of output in the paper industry. Increased energy use to improve the quality of paper products, however, has largely cancelled out this trend.

Specific Manufacturing Industries

The chemical and rubber industry and the primary metals industry account for most of the energy consumed in manufacturing other than petroleum refining. The chemical and rubber industry is projected to consume only slightly more energy for heat and power in 1990 than in 1983 (2.4 versus 2.2 quadrillion Btu), despite a growth in real output of 40 percent. This is due partly to conservation, and partly to the growth of drug, soap, and paint output relative to basic chemicals.

Basic metal production (mostly steel) is projected to increase about 35 percent from 1983 to 1990 in the projections presented in this report. Energy use, in contrast, increases only 26 percent in that industry. Energy costs, as a percent of total production costs, are projected to decrease very slightly as a result of a considerable shift toward increased reliance on electricity in steel production.

Most of the remaining energy use is consumed almost equally by three industries: paper; stone, clay, and glass; and food. In the paper industry, energy costs are projected to increase from 6.9 percent of total production costs in 1983 to 8.0 percent in 1990, as a result of energy price increases. Energy use is projected to increase at the same rate as output (up by 25 percent from 1983 to 1990). The energy-saving effects of recycling wood products are projected to cancel out the requirement for additional purchased energy in order to produce higher quality paper and board.

The food industry, like the steel industry, is projected to hold down energy costs by relying more on electricity. Even though output is projected to increase by about 17 percent in this industry, energy use is projected to decrease by almost 7 percent from 1983 to 1990; electricity increases slightly as fossil fuels decrease. This continues a historical trend associated with the greater use of efficient microwave ovens and more efficient freezing. In some cases, freezing may be a value-enhancing alternative to chemical preservatives and processing techniques.

Stone/clay/glass is a highly cyclic industry, like primary metals; its output also is assumed to grow rapidly (31 percent), and its energy use to rise. However, energy costs as a share of total production costs decrease from 8.8 percent to 7.6 percent, because of the growing share of coal and electricity. The cement and lime sectors of this industry are where coal has replaced oil significantly in manufacturing after the 1974 embargo. Coal is projected to meet almost all the energy needs of cement making by 1990. In the rest of the industry, the historic trend towards increased reliance on electricity is important. Natural gas use declines by 11 percent by 1990 in this industry, despite the projected large increase in output; about a third of this decline is expected to be met by greater use of residual oil.

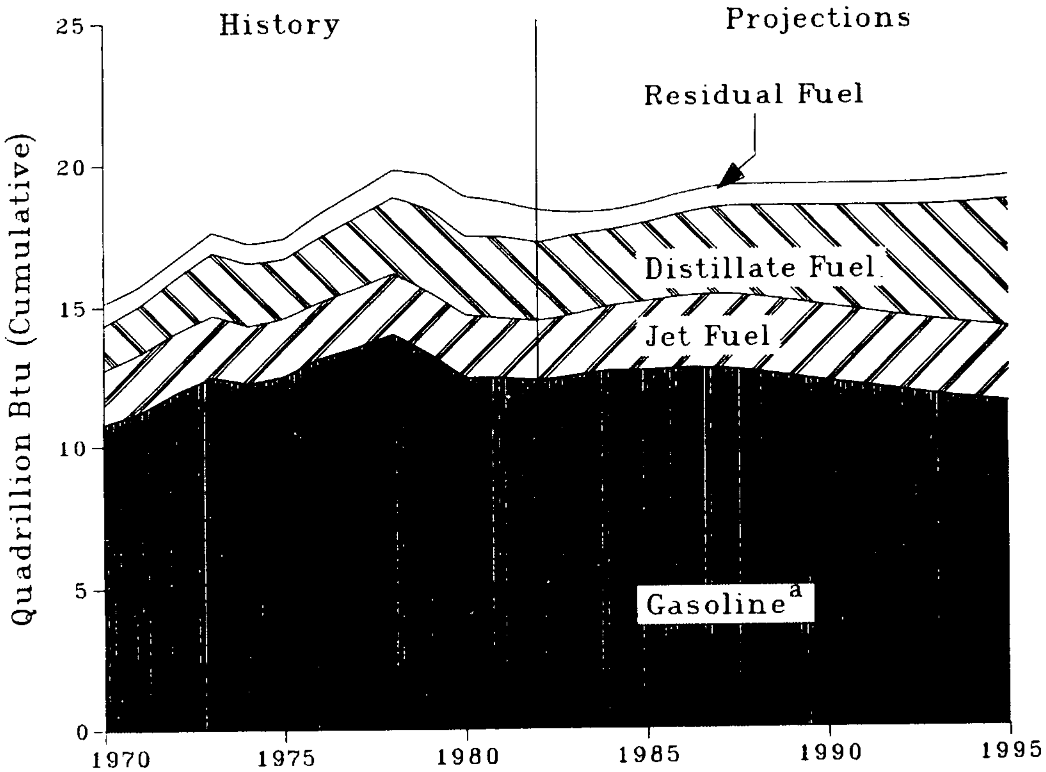
Transportation Sector

The transportation sector accounted for over a third of total end-use energy consumption and nearly two-thirds of end-use petroleum product demand in 1983. Transportation energy needs rely almost entirely on petroleum products. Substitution of other fuels for oil is not expected to play a significant role through the forecast period.

Figure 21 and Appendix Table A9 contrast historical and projected trends in transportation sector fuel use. Greater energy efficiency is being built into the capital stock as more fuel efficient cars, trucks, and aircraft join the national fleets and replace older equipment. Motor gasoline use, which accounted for an estimated two-thirds of the transportation sector's energy use in 1983, is projected to decline by 1995 in response to improving average fleet efficiency and increased reliance on diesel-powered vehicles.

By 1995, motor gasoline use is projected to be about 9 percent below its 1983 level in the midprice case, even though total vehicle-miles traveled in gasoline-powered vehicles is projected to increase significantly. In the high price case motor gasoline use is projected to decline at about twice the rate of the midprice case and in the low price case motor gasoline use in 1995 is projected to be about the same as it was in 1983 (Appendix Tables A9, B9, and C9). Over the same period, increased economic activity and growth in the share of

Figure 21. Transportation Petroleum Use, Midprice Scenario, 1970 to 1995



[a]Motor and aviation gasoline.

Note: Transportation use of liquefied petroleum gases does not exceed 0.02 quadrillion Btu per per year and is not shown in the figure.

Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

diesel-fueled cars and trucks are projected to lead to a significant increase in diesel fuel use. Diesel-powered vehicles are projected to consume about 17 and 22 percent of the transportation sector's energy use in 1990 and 1995, respectively, compared to about 15 percent share in 1983. Total highway fuel use (motor gasoline plus diesel) is projected to increase only slightly between 1983 and 1995 in the midprice case, even though total vehicle-miles traveled is projected to grow at an average annual rate of about 4.6 percent. Uncertainties associated with these projections are discussed later in this section.

Motor gasoline and diesel fuel prices are projected to have a significant effect on both vehicle-miles traveled and average fleet efficiency. In the high world oil price case, these fuels are priced more than 50 percent higher than in the low world oil price case in 1995 (Appendix Tables B5 and C5). In response to these higher prices, the 1995 projection for automobile vehicle-miles traveled is about 12 percent lower in the high world oil price case than in the low world price case. The automobile fleet efficiency in 1995 is projected to be 7.8 percent higher in the high world oil price case than the lower world oil price case. Total 1995 automobile fuel use is projected to be nearly one-fifth lower in the high world oil price case than in the low world oil price case.

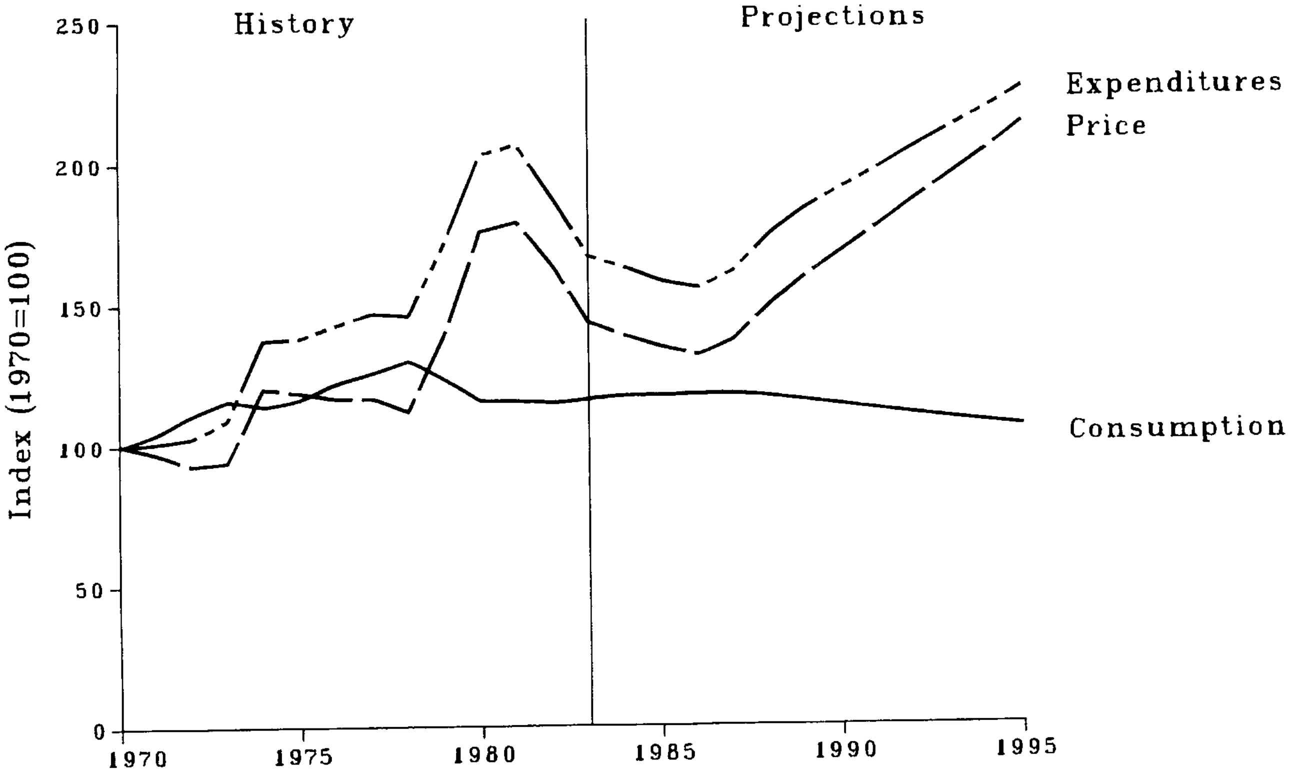
Automobiles

Automobiles used about one-third of the economy's end-use oil consumption in 1983. This share is projected to decline slightly by 1995 in response to continued improvements in automobile fuel-use efficiency. Most of this oil consumption is in the form of motor gasoline used for highway transportation.

Figure 22 indicates changes in total transportation sector motor gasoline consumption, prices, and expenditures since 1970. In the two decades prior to 1973, annual U.S. motor gasoline use never declined. In contrast, from 1978 to 1982, motor gas use declined by more than 10 percent. Gasoline prices, Federal fuel-economy standards, and a slack economy help explain this decline. As shown in Figure 22, real motor gasoline prices increased sharply from 1973 to 1974 and again from 1978 to 1980. These sharp increases in price were not fully reflected in consumer expenditures. Consumers reacted to the higher motor gasoline prices and the long lines at service stations by traveling less. From 1978 to 1980, while real fuel prices increased by over 50 percent, expenditures for motor gasoline increased considerably less.

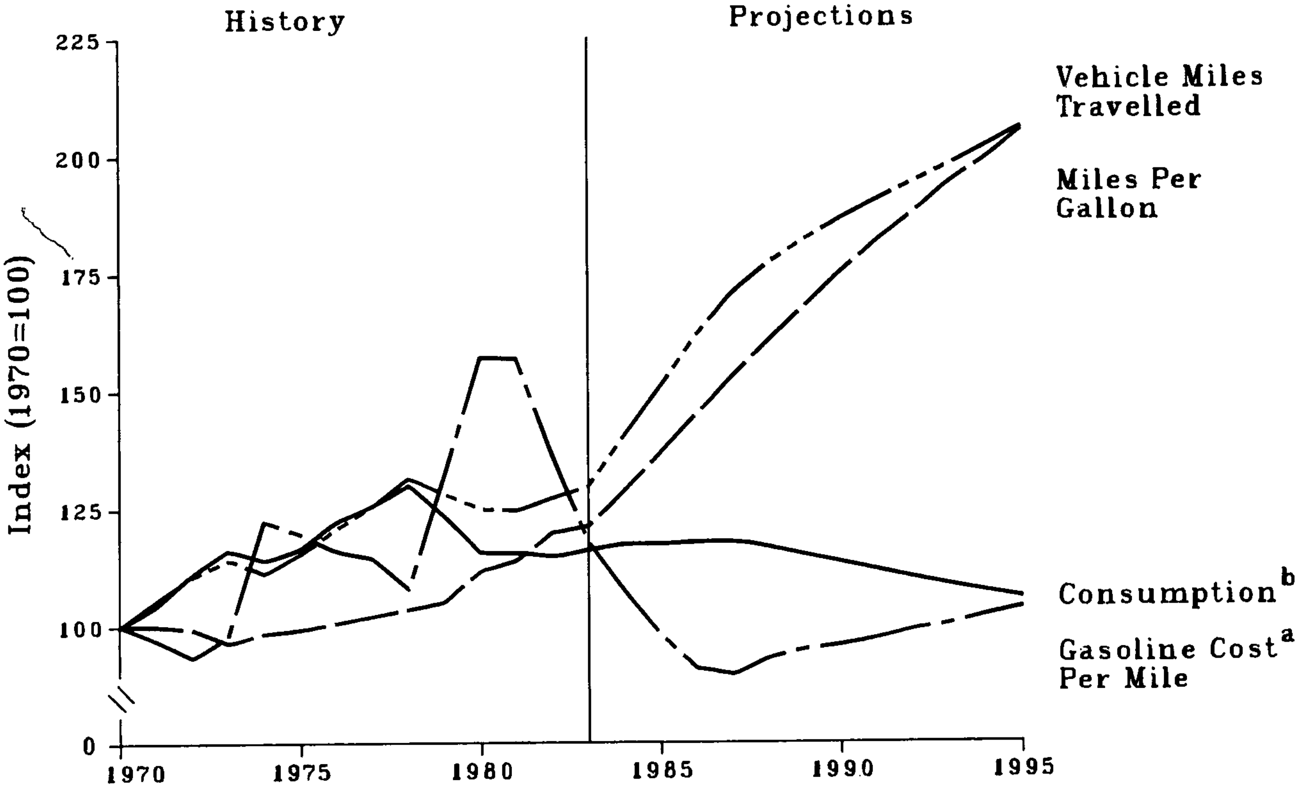
Motor gasoline and diesel fuel prices in the midprice case are projected to decline moderately between 1983 and 1986, and 1987 prices are still below the 1983 price of motor gasoline and diesel fuel (Appendix Table A5). After 1987, motor fuel prices are expected to increase significantly. By 1995, real motor gasoline prices are forecast to be about 47 percent higher than the price in 1983. As shown in Figure 23, automobile fuel consumption is stable through 1987 but declines afterward, as the rate of increase in vehicle-miles traveled slows in response to higher motor gasoline prices.

Figure 22. Indexes of Motor Gasoline Use in the Transportation Sector, Midprice Scenario, 1970 to 1995



Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Energy Price and Expenditure Data Report, 1970-1980, DOE/EIA-0376.

Figure 23. Indexes of Automobile Fleet Characteristics, Midprice Scenario, 1970 to 1995



[a]Gasoline-powered vehicles account for most automobile fuel consumption. In 1983, the diesel powered share is estimated to be less than 3 percent. For 1995, the share is estimated to be about 5 percent in the midprice scenario.

[b]Motor gasoline plus distillate (diesel) consumption.

Source: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Federal Highway Administration, Highway Statistics, U.S. Department of Transportation, Annual Reports 1970 through 1982, (Washington, D.C.).

Automobile Fleet Characteristics. Figure 23 traces historical and projected trends in gasoline cost per mile, automobile fleet efficiency (miles per gallon), vehicle-miles traveled, and total automobile fuel use. Significant increases in gasoline prices have occurred since 1973. However, the impact on consumers of the two major gasoline price jumps since 1973 was moderated by the steadily improving average fleet efficiency. While the real cost per gallon of gasoline increased by over 70 percent from 1973 to 1982, the average fuel cost of driving a mile increased considerably less. For new-car buyers, the fuel cost of driving a mile has actually decreased since 1973, reflecting a near doubling of new-car fuel efficiency. The rate at which new-car fuel efficiency affects the average fleet efficiency depends directly on the level of new-car sales and the rate at which older cars are scrapped. Between 1979 and 1982, for example, new-car sales were down sharply as consumers held on to their existing vehicles longer. If this decline in new-car sales had not occurred, the average fleet efficiency in 1982 would have been significantly higher.

Projections of fuel efficiency appearing in this report are based on analyses of data covering the major gasoline price increases of the past decade. With the recent stability in real gasoline prices, serious questions concerning the rate at which the fuel efficiency of new cars will continue to improve have been raised. Both Ford and General Motors have indicated that they will not meet the 1983 Corporate Average Fuel Economy standard of 26.0 miles per gallon. Also, if gasoline prices stay down, they may have difficulty in meeting the 1984 and 1985 standards as well.[14] These issues are discussed below. The most recent data do indicate, however, that motor gasoline consumption in 1983 was about 1 percent above the 1982 level; the first increase since 1978.

Most of the fuel efficiency improvements realized since 1974 have been the result of downsizing and reductions in horsepower.[15] New technologies have not had a major impact on new-car fuel efficiency so far. To the extent that consumers prefer larger, more powerful cars in an era of ample gasoline supplies and stable prices, some of the efficiency improvements made so far may be reversible. This fact makes new-car fuel economy very difficult to predict.

Projections of average fleet miles per gallon in this report are directly related to projected motor gasoline prices. In the high price case projected automobile fleet efficiency in 1995 is about 8 percent higher than in the low price case (Appendix Tables B9 and C9). At higher gasoline prices, additional fuel economy improvements, which can be made using available technology, become cost effective. In making such projections, however, there remains considerable uncertainty in evaluating how consumers will react to vehicle design and performance changes associated with fuel economy improvements. Estimates of new-car fuel efficiency implicit in the projections of average fleet miles per gallon may be somewhat overstated if consumers react negatively to changes in car characteristics involved in increasing fuel efficiency.

Data covering new-car sales indicate that large cars have regained some of the market share lost during the 1979-80 motor gasoline price increases. Large-car sales in 1983 accounted for about 15 percent of all car sales compared with 13 percent in 1982. In contrast, the large-car market share in 1978 was nearly 23 percent.[16]

New-car fleet fuel economy for 1983 declined slightly from the 1982 level. This is the first decline since 1974. Nevertheless, the fuel efficiency of new large cars remains considerably above the average fleet fuel efficiency.

New cars in 1983 were about three-fifths more fuel efficient than the average of the fleet and the projected fleet average miles per gallon estimate is significantly affected by the rate at which new cars displace older, less fuel efficient cars. Even if new car fuel efficiencies do not continue to improve at the rate realized from 1979 to 1982, considerable improvement will continue to occur in the average fleet efficiency. This is particularly relevant for the next few years as the economy recovers and pent-up demands for new cars are realized. From 1983 to 1995, average fleet efficiency is projected to increase at an average annual rate of about 4.5 percent.

If it were not for the past and projected efficiency improvements, discussed above, fuel consumption would increase at the same rate as vehicle-miles traveled. As shown in Figure 23, vehicle use has increased considerably since 1973. Almost all of this increase occurred between 1975 and 1978, during a period of stable gasoline prices. Between 1979 and 1980, gasoline price increases, as well as a recessionary economy, resulted in declining vehicle use. More recently, vehicle-miles traveled has increased in response to falling real gasoline prices and an improving economy. Automobile vehicle-miles traveled is projected to increase at an average annual rate of about 3.9 percent from 1983 to 1995.

Nonautomobile Fuel Use

Projected truck fuel consumption parallels automobile fuel use. An increase in fuel efficiency of nearly 4.3 percent annually (arising in part from increased diesel engine use) is projected from 1983 to 1995. Truck use is heavily dependent on the demand for goods transportation which in turn reflects the level of economic activity. Truck fuel use is projected to increase throughout the forecast period in response to a projected average annual rate of increase in truck vehicle-miles travelled of about 6.0 percent between 1983 and 1995.

Jet fuel use accounted for about 11 percent of the transportation sector's energy requirements in 1983. During the 1970's, airlines were able to reduce fuel consumption per passenger mile by over 50 percent by modifying flight schedules, improving aircraft assignment, and adjusting flight size. It is estimated that technical efficiency improvements were responsible for relatively small gains in efficiency over this period.[17]

The 1995 forecast projects a substantial increase in airline activity offset largely by continued improvements in average fuel efficiency. Consequently, jet fuel consumption is projected to increase at an average annual rate of only about 1.7 percent between 1983 and 1990, compared to a projected annual increase in airline activity of 5.3 percent.

Apparent residual fuel oil consumption in transportation, used primarily as ocean-going ships' bunker fuel, has decreased sharply since the decontrol of domestic oil markets. Some of this decline may be due to a rise in U.S. bunker fuel prices relative to prices elsewhere. There remains considerable uncertainty associated with projections of residual fuel use in the transportation sector.

[1]Energy: An Uncertain Future, Committee on Energy and Natural Resources, United States Senate, Publication No. 95-157, December 1978.

[2]Estimates of end-use energy consumption were made in the Office of Energy Markets and End Use using the Residential Energy Consumption Survey. The forecasts are documented in Energy Information Administration, Model Documentation: Household Model of Energy, DOE/EIA-0409 (Washington, D.C., 1984).

[3]Various household data in this paragraph are from U.S. Department of Commerce/Bureau of the Census publications: Characteristic of New Housing: 1982 and Annual Housing Survey: 1981 General Housing Characteristics.

[4]Estimates of energy consumption by building type are based on the Nonresidential Buildings Energy Consumption Survey. The forecasts are documented in the forthcoming "Commercial Sector Energy Model Documentation."

[5]See Energy Information Administration, "Documentation of the PURHAPS Industrial Demand Model," Volume I, DOE/EIA - forthcoming.

[6]Workshop on Structural Change and Industrial Electricity Demand, Electric Power Research Institute, Palo Alto, Calif., October 1983.

[7]The Future of Electric Power in America, DOE/PE-0045, U.S. Department of Energy, (Washington, D.C. 1983).

[8]Energy Information Administration, A Statistical Analysis of What Drives Industrial Energy Demand, DOE/EIA-042013 (Washington, D.C., 1983).

[9]Strictly speaking, changes in electricity use as a share of total energy use may not be "due" to fuel choice changes, but that is the basic assumption here.

[10]Energy Information Administration, A Statistical Analysis of What Drives Industrial Energy Demand, DOE/EIA-042013 (Washington, D.C., 1983), Appendix B.

[11]Energy Information Administration, A Statistical Analysis of What Drives Industrial Energy Demand, DOE/EIA-042013 (Washington, D.C., 1983), Chapter 6.

[12]American Gas Association, Historical and Projected U.S. Natural Gas Demand From Mining, Manufacturing and Agricultural Industries, Policy Evaluation and Analysis Group (Arlington, Va., 1983).

[13]U.S. Bureau of Census, 1982 Census of Manufactures: Fuels and Electric Energy Consumed, Census Report MC82-S-4 (Washington, D.C., 1983).

[14]Automotive News, "Ford Joins GM in Saying it won't Meet '83 CAFE," (January 17, 1983) p. 8.

[15]U.S. Department of Transportation, National Highway Traffic Safety Administration, Automotive Fuel Economy Program, Sixth Annual Report to Congress (Washington, D.C., 1982).

[16] Motor Vehicle MPG and Market Shares Report, Oak Ridge National Laboratory, Energy Division, (Oak Ridge, Tenn., 1984), p.6.

[17] U.S. Department of Energy, Office of Conservation and Renewable Energy, Trends in Energy Use and Fuel Efficiency in the U.S. Commercial Airline Industry, (Washington, D.C., 1982), p. 14.

5. Domestic Energy Supply

The United States is the world's largest producer and consumer of energy. Although energy imports have been a cause of public concern in the recent past, net imports were equal to only 12 percent of U.S. energy consumption in 1983. Most of this concern is with oil. Net oil imports declined from 1977 to 1983, when they were equal to about 30 percent of U.S. oil consumption and were at the lowest level since 1971. The Nation has been about 95 percent self-sufficient in natural gas for many years and is the world's largest exporter of coal.

Petroleum (including natural gas liquids), dry natural gas, and coal accounted for about 43, 25, and 22 percent, respectively, of the 70.5 quadrillion Btu of energy consumed in the country in 1983. U.S. reserves of petroleum, natural gas, and coal are approximately 11 years', 12 years', and 3 centuries' supply at recent rates of production.

Proved Reserves of Crude Oil Declined in 1982;
Natural Gas and Natural Gas Liquids Reserves Stable

As of December 31, 1982, U.S. proved reserves of hydrocarbons are estimated to have been 27.9 billion barrels of crude oil, 202 trillion cubic feet of dry natural gas (excluding gas in underground storage), and 8.8 billion barrels of natural gas liquids (including lease condensate). After 2 years of relative stability, proved reserves of crude oil decreased by 5.3 percent during 1982, resuming the downward trend observed during the 1977-79 period. While total oil discoveries were only slightly below the 1981 level, downward revisions of estimates for existing reserves were significantly larger than in 1981. Proved reserves of dry natural gas and natural gas liquids, however, remained relatively stable for the third consecutive year. Dry natural gas reserves fell by only 0.1 percent while natural gas liquids reserves increased by 2.2 percent. Total liquid hydrocarbon reserves (crude oil plus natural gas liquids) declined by 3.9 percent, as production held fairly steady. While new reservoir discoveries in old fields increased during 1982 for all three fuel types, they were not sufficient to counterbalance the decreases in extensions and new field discoveries. Total reserves accounted for by discoveries, therefore, dropped by 11.2 percent for oil, 16.1 percent for gas, and 22.0 percent for natural gas liquids.

These estimates are based on an analysis of data filed by 2,722 operators of oil and gas wells and by 971 operators of natural gas processing plants reported in EIA's U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 1982 Annual Report, DOE/EIA-0216(82) (Washington, D.C., September 1983).

U.S. energy consumption is expected to rise from 1983 levels as a result of the current economic recovery. The energy source that is most flexible in order to adjust energy supplies to variations in demand by the U.S. economy is imported petroleum. Increased oil consumption is met by increased net imports of crude oil and products, which are projected to rise from 4.3 million barrels per day in 1983 to 7.0 million barrels per day in 1995 in the midprice projection. While U.S. coal production is projected to rise through the forecast period, oil and natural gas production are expected to stabilize through the 1980's, then decline slowly in the 1990's (Figure 24).

Petroleum

Overview. Petroleum consumption and imports, which had been declining since reaching their respective peaks in 1978 and 1977, were above year-earlier levels in the second half of 1983 and are expected to rise with continued growth in the U.S. economy (Figure 25). In addition, the major drawdown of primary inventories since mid-1981 (a response to lower demand, declining oil prices, and continued high real interest rates) apparently has ended.

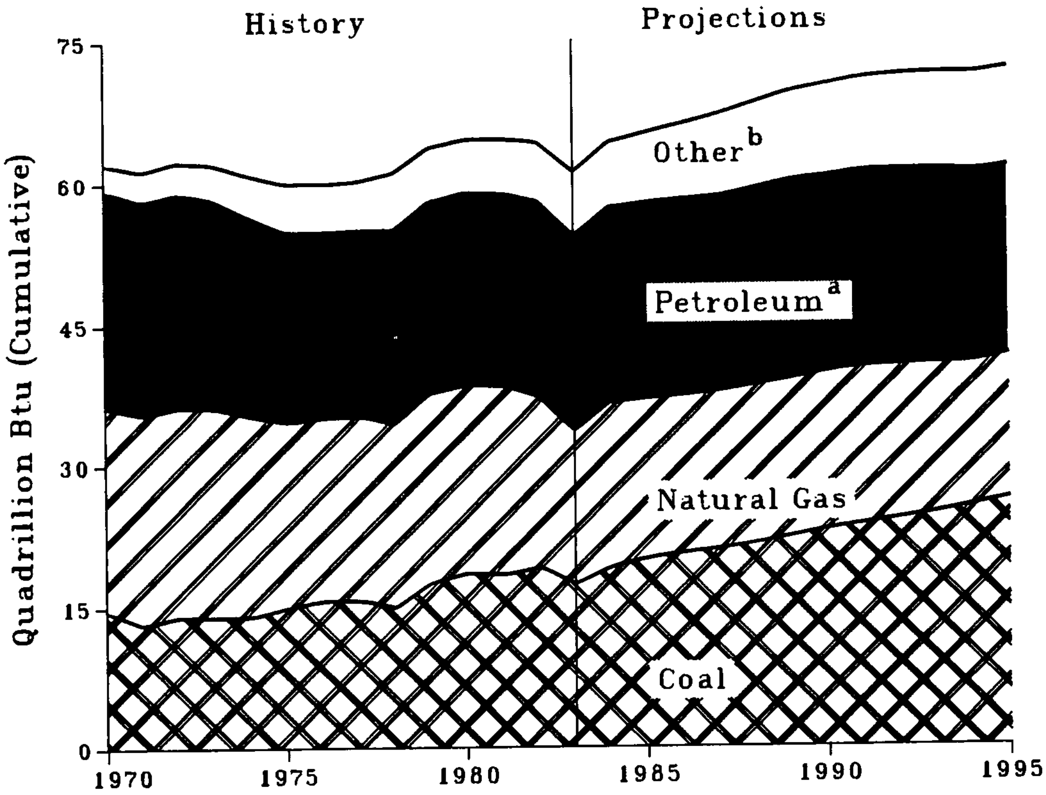
Although the domestic production of crude oil and natural gas liquids is now lower than in the peak year of 1970, generally stable production is projected through the 1980's, followed by a slow decline in the early 1990's (Figure 26). Petroleum consumption is projected to grow at about half the rate of GNP, continuing to be constrained by conservation-motivated investments in all sectors of the economy, by environmental legislation, and by the outlook for sustained high world oil prices. Uneven demand growth across the major sectors of the economy, however, is expected to result in an increase in the relative demand for heavier fuel oils for industrial and electric utility use and as petrochemical feedstocks (Figure 27). Overall growth in transportation fuel consumption through the forecast period, largely for diesel fuel, is projected to average about 0.7 percent per year, while gasoline consumption declines by about 9 percent from 1983 to 1995. As a result of rising petroleum consumption and stable or declining domestic production, a resurgence is expected in crude oil and refined product imports.

Over the range of future world oil prices examined, petroleum consumption is more variable than the consumption of any other energy source. About 39 percent of the shift in oil consumption between the high and low price cases in 1995 occurs in residual fuel oil use by electric utilities. Motor gasoline accounts for an additional third of this shift.

Petroleum Exports. Since 1981, exports of refined petroleum products have increased. Following the December 1973 Arab oil embargo, quotas were established on the export of most petroleum products. These product quotas have now been lifted, but restrictions on the export of crude oil remain in force. (See box reviewing Federal export regulations.)

Product exports, consisting primarily of residual fuel oil and minor products (mainly waxes, lubricants, and petroleum coke), had averaged about 200,000 barrels per day before the embargo and remained at that level through 1980. By 1983,

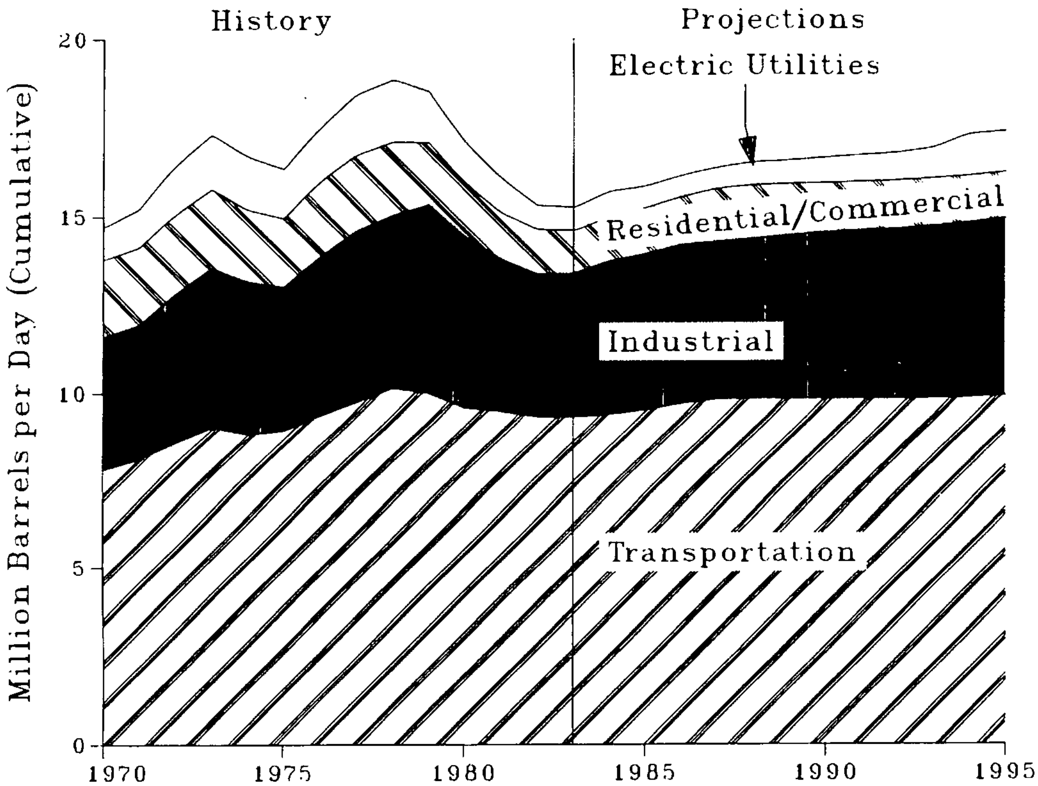
Figure 24. Domestic Energy Production by Source, Midprice Scenario, 1970 to 1995



[a]Includes natural gas plant liquids.
[b]Includes nuclear power, hydropower, geothermal energy, and electric utility consumption of wood and waste.

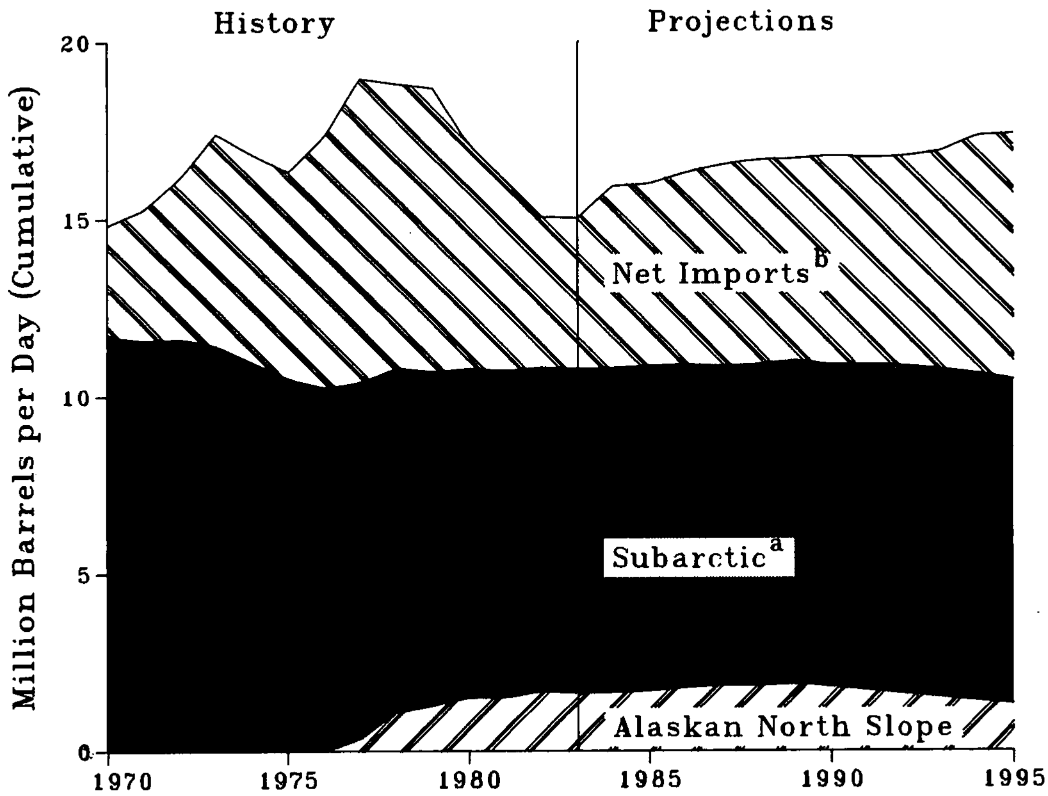
Sources: Historical data: Energy Information Administration, Annual Energy Review 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

Figure 25. Oil Consumption by End Use, Midprice Scenario, 1970 to 1995



Note: Industrial oil consumption includes refinery fuel use.
Source: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983).

Figure 26. Petroleum Supplies by Source, Midprice Scenario, 1970 to 1995

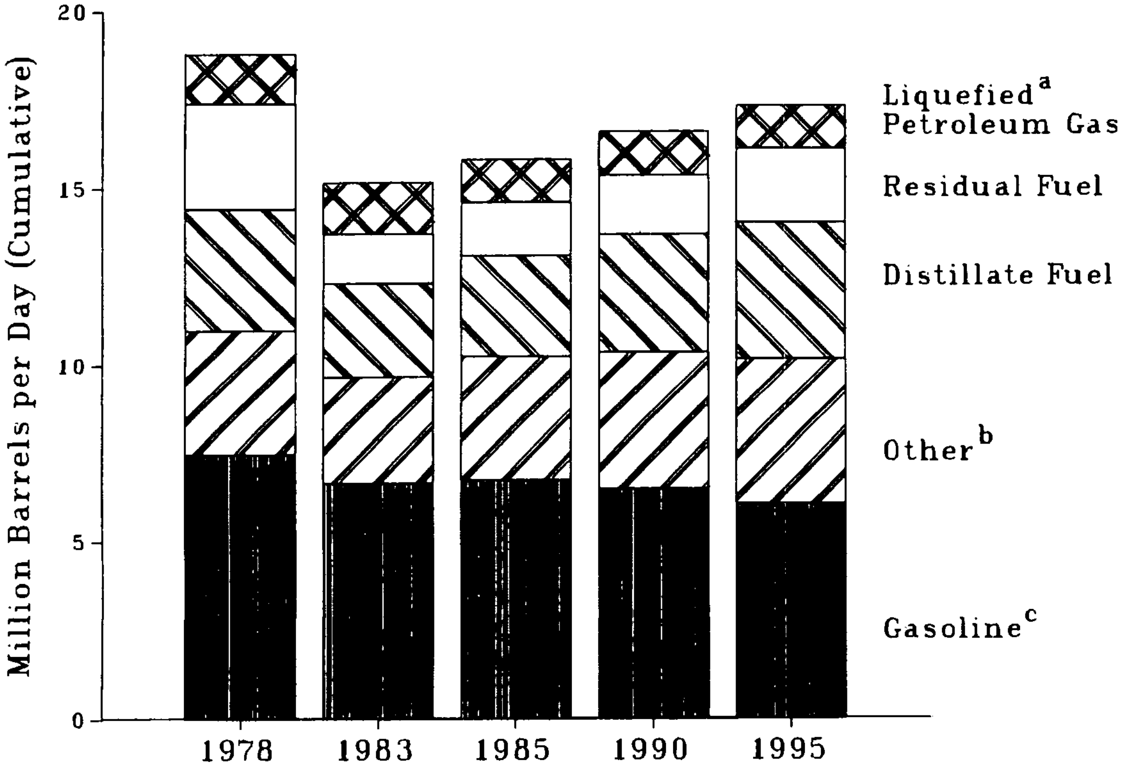


[a]Includes offshore production, natural gas plant liquids, and other domestic production.

[b]Includes imports for the Strategic Petroleum Reserve.

Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); Short-Term Energy Outlook, DOE/EIA-0202(84/1Q).

Figure 27. Petroleum Products Supplied, Midprice Scenario, Selected Years



[a]Computed as domestic consumption of liquid petroleum gases (LPG's) used for heat and power minus net imports of LPG's. Refinery fuel use of LPG's is included, but LPG's consumed as feedstocks (and all ethane) are shown in Other products.

[b]Includes petrochemical feedstocks, ethane, natural gasoline, isopentane, unfractionated stream, plant condensate, other liquids, and all finished products not shown explicitly.

[c]Includes motor and aviation gasoline.

Source: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984).

product exports averaged 575,000 barrels per day. In addition, 1983 crude oil exports (mainly to the U.S. Virgin Islands and some barrel-for-barrel exchanges with Canada) averaged about 164,000 barrels per day.

The increase in product exports came in two steps. Concurrent with the end of crude oil price controls, exports increased over 100,000 barrels per day in February 1981. Additional increases came in September 1981, when the Department of Commerce removed all quantity restrictions on product exports (although the licensing requirement remains). Total product exports averaged 367,000 barrels per day in 1981, 579,000 barrels per day in 1982, and 575,000 barrels per day in 1983.

This increase is attributable to residual fuel oil, petroleum coke, distillate fuel oil, and liquefied petroleum gases (LPG). Exports are almost exclusively from West Coast and Gulf Coast refineries, with coke supplied increasingly as a byproduct of new, downstream refining processes.

It is likely that export growth will slow with a continuation of the current economic recovery, as domestic industrial demands for residual fuel oil and coke increase. Further refinery investments to upgrade the quality of products refined from increasingly heavy crude oils are expected to lower the cost of these less profitable byproducts, thereby enhancing their competitive positions in international markets.

Petroleum Export Regulations

The issue of Federal controls on petroleum exports was highlighted in 1983 with debate on whether to allow exports of Alaskan North Slope crude oil. Exports of crude oil and major refined products are regulated by a number of Federal laws.

The Export Administration Act (EAA), renewed in 1983, authorizes the President to restrict exports when it is determined that those exports would be to the National detriment. The EAA authorized the initial imposition of quotas on gasoline, kerosene, distillates, aviation fuels, residual fuel oils, and most naphthas. Export licenses, but not quotas, were required for residual products such as coke and carbon black. However, exports of petrochemical feedstocks, waxes, and lubricating oils were not controlled. Before the EAA, the Mineral Lands Leasing Act (1970) (MLLA) and the Outer Continental Shelf Lands Act (1953) both required a Presidential finding that any export of crude oil would not diminish the quantity or quality of oil available to the United States or increase imports. The Trans-Alaska Pipeline Authorization Act (1973) extends the provisions of the MLLA to North Alaskan production. Finally, the Energy Policy and Conservation Act (1975) requires the President to promulgate export control regulations. Export quotas and licensing are managed by the Department of Commerce and enforced with the adoption of "Short Supply Control" regulations.

Domestic Crude Oil and Natural Gas Liquids. The Nation's principal source of petroleum is still domestic crude oil and natural gas liquids production. These sources provided 70 percent of the Nation's petroleum consumption in 1983. However, this figure is projected to decline to about 57 percent by 1995, as imports increase to accommodate most of the country's growing petroleum consumption. Although the longer term outlook for future world oil prices has been revised significantly downward in recent years, the outlook is for domestic production of crude oil and natural gas liquids to remain relatively stable through the 1980's.

Dramatic increases in domestic drilling activity following the 1979-80 rise in world oil prices peaked at record levels at the end of 1981, then gave way to equally dramatic declines in 1982 and 1983. But this decline in drilling levels, triggered by the nearly $3 per barrel decline in oil prices in early 1982, a decline in new gas prices, and a worsening economy associated with the tightening of credit at that time, has thus far not been accompanied by a decrease in production. However, new discoveries have fallen in rough proportion to the decline in exploratory drilling.

With continued depletion of the underlying resource base, the average volume of crude oil reserves added per foot drilled, referred to as the finding rate, is expected to decline. As a result, the total cost of maintaining domestic reserves is expected to increase. However, divergences from this resource-driven pattern of declining finding rates may occur as an initial response to a sudden rise in oil prices. For example, if oil prices were to rise sharply, firms may shift their activities to the search for readily available, smaller oil deposits that become economically attractive prospects at higher oil prices.

Thus, the doubling of oil prices in real terms following the Iranian revolution, combined with normal constraints on the pace at which major new oil resources can be developed, made many of the small, higher cost, lower potential deposits in this country profitable and stimulated the entry of many more small drilling operators. The search for lower potential deposits and the employment of increasingly less-efficient crews and equipment led to a drop in the domestic crude oil finding rate (the average volume of reserves added per foot drilled) in the 1979 through 1982 period, roughly 25 percent lower than that experienced in the preceding years.

With the subsequent declines in oil prices in early 1982 and again in early 1983, the least efficient of these new drilling operations became uneconomic; the average number of rotary rigs in operation fell by over 43 percent from 1981 to 1983. Remaining operators, however, have benefited from the resulting decline in demand for seismic services, drilling rigs, tubular goods, etc., as exploration and development costs fell sharply from 1981 to 1983. At the same time, the impact of declining oil prices on net producer revenues has been further softened by an offsetting decline in windfall profit tax payments--a $5 per barrel decline in the oil price currently translates into a $1 per barrel decline in after-tax revenues per barrel. Thus, even after the additional $5 per barrel decline in oil prices in early 1983, exploration and development activity remain sufficiently profitable to sustain current activity levels. The near-term outlook is for stability in domestic drilling for oil (in contrast to natural gas, as discussed in the next section), with crude oil finding rates returning to their historical rate of decline.

Effects of Windfall Profits Tax Covered in EIA Studies

An analysis of the key features of the United States crude oil windfall profit tax (WPT) to indicate the initial impact of the tax is contained in An Analysis of the Crude Oil Windfall Profit Tax, April 1983, (EIA/DOE-0398).

The qualitative analysis presented in the paper indicates several effects on crude oil exploration, development, and production activity that should be anticipated as a result of the windfall profit tax. Major conclusions of the conceptual analysis are as follows:

- The tax can be expected to result in lower domestic crude oil production unless, because of increasing world oil prices and constraints on domestic petroleum activity, rates-of-return on petroleum investments substantially exceed the returns on alternative investments. The provision in the tax law for terminating the tax by a known date may result in a slowdown in the rate of crude oil production (such as through abandonment, prolonged maintenance shutdowns, or retarded rates of development) as the termination date approaches.

- Distortion of the relative levels of investment in exploration, development, and production activities would be expected as firms invest more heavily in lower risk projects and capital is redirected from investments subject to higher effective tax rates to those associated with lower tax rates, and firms adjust production activities in order to reclassify high-tax oil production streams into low-tax production. It is possible that the incremental enhanced oil recovery (EOR) provision of the tax law may result in investment in token, inefficient EOR projects.

- Provision of lower tax rates for independent producers may result in increased production by independents in the near term.

- Limiting the windfall tax liability to 90 percent of the net income from a property may provide an incentive to accelerate purchases of certain tax-deductible items.

The analysis indicates no clear impact of the tax on petroleum activity in its first year.

Recent exploration activity indicates several new areas of particular promise. Perhaps most dramatic is the series of discoveries reported in offshore California--including the giant Point Arguello field and possibly five additional giants, that is, fields that contain more than 100 million barrels of recoverable oil. These discoveries are expected to contribute to a rise in production from offshore California over the forecast period that will generally offset declining production from the Gulf of Mexico.

Despite the recent disappointment with the lack of a petroleum discovery at the Mukluk well in Alaska, the recent Federal leasing of tracts in the Beaufort Sea offers potential for the discovery of new fields. Due to long lead times prior to production, any new discoveries in North Alaska are unlikely to contribute significantly to domestic supplies in this decade. Production from new discoveries is projected to rise above 100,000 barrels per day in 1995. This figure would be higher if technological developments allowed for more rapid development of the areas near the existing Alaskan pipeline system.

Currently, most activity in the proven Prudhoe Bay and Kuparuk fields is concentrated on development. Massive waterflooding projects (a secondary recovery technique) were initiated in 1983 in an effort to sustain production from those fields, and production from these proven reserves is forecast to remain as high as 1.81 million barrels per day in 1990. North Alaskan production is expected to peak in 1989 at 1.91 million barrels per day, declining to 1.31 million barrels per day by 1995.

The anticipated declines in Alaskan and conventional Lower-48 States onshore production are expected to be offset by steadily increasing production from enhanced oil recovery techniques and increased production from offshore California. Enhanced oil recovery is projected to contribute roughly 700,000 barrels per day in 1990. Supplies from this source are expected to be a major factor in the generally stable total production levels through the 1980's.

Across the scenarios, domestic petroleum production varies with the average world oil price, increasing by 1.8 million barrels per day in 1995 with a high oil price and decreasing by 1.2 million barrels per day with a low price. The change in production is due to the more marginal sources, those sources that are smaller, riskier, or more expensive, that become profitable as oil prices increase.

Petroleum Imports. Imported crude oil has generally been the marginal source of oil supply to this country, absorbing most variation in total consumption levels. Changing inventory economics (discussed below), however, have at times added to the effective domestic demand for oil, increasing oil imports for stock buildup. Since mid-1981, product stock drawdowns have supplemented domestic refinery output, reducing oil import requirements.

The EIA outlook is for an increase in net crude oil imports from 3.1 million barrels per day in 1983 to 5.5 million barrels per day by 1995. Relatively stable domestic oil production and a resumption of demand growth with recovery of the domestic economy are the principal factors behind this projected turnaround in oil imports.

Due to current refinery investments aimed at increasing the yield and quality of the lighter fuels used in transportation, there is also an outlook for increasing imports of heavier fuel oils. Low-cost, seasonal operation of unsophisticated, heavy-fuel refineries in the Caribbean Basin has historically been an important source of distillate and residual fuel oil to East Coast U.S. markets during the winter months. Total net product imports are projected to increase from 1.1 million barrels per day in 1983 to 1.4 million barrels per day by 1995. With the current strong economic recovery, residual fuel oil imports, in particular, are expected to satisfy the major part of the increased industrial demand.

As in the past, petroleum imports are the most flexible source of energy as the domestic market changes. It is projected that, by 1995, net imports of petroleum decline by 3.4 million barrels per day under the high world oil price scenario and increase by 2.9 million barrels per day in the low scenario. Part of the change is the increased domestic production that occurs as prices rise, and part is the general decline in overall energy consumption and in petroleum consumption with higher prices.

Domestic Refining Activity. The domestic refining industry is undergoing long-term adjustments in response to the slowdown in product demand, a shift in the desired product mix, the declining quality of available crude oils, and changes in Federal regulations.

With the recent recession and price-induced conservation, total petroleum product supplied dropped almost 20 percent from the peak in 1978 to 1983. Refinery capacity, measured as operable crude oil distillation capacity, has been declining since 1981, but still exceeds U.S. petroleum consumption. Even with the longer term outlook for a significant recovery in petroleum products supplied, to 17.37 million barrels per day by 1995, unused distillation capacity is expected throughout the decade. Total refinery runs of crude oil are projected to increase by over a million barrels per day by 1990--well within the capability of current capacity.

On January 1, 1983, 258 operable refineries existed in the United States, compared with 324 refineries 2 years earlier. Operable distillation capacity declined by 1.7 million barrels per day over this same period. Of the 63 refineries shut down in 1982 alone, 28 were less than 8 years old and 18 of these had capacity of less than 10,000 barrels per day. These 18 small refineries had been built in response to the special incentives available during the petroleum price control program. Another 25 of the shutdowns were refineries more than 25 years old. This "shakeout" of less-efficient refineries has now slowed.

The drop in total petroleum consumption has been accompanied by shifts in the composition of products supplied. The share of demand accounted for by lighter gasoline-type products increased from about 40 percent of total product supplied in 1978 to 45 percent in 1982. At the same time, consumption of heavier products, such as residual fuel oil, declined by comparable amounts.

A basic shift in the processing capabilities of domestic refineries represents one way the industry has responded to this demand shift. Thus, the general decline in distillation capacity over the last 2 years has not been accompanied by comparable declines in downstream capacity. As a result, the average complexity and flexibility of domestic refineries has increased--refiners can now produce a wider range of products from a given stream of crude oil.

Current investment trends indicate a continued increase in refinery capabilities to produce more light fuels and to process crude oil of increasingly lower quality, yet the long-term outlook is for a decline of the combined gasoline/distillate fuel oil refinery yield, from about 69 percent in 1983 to 65 percent in 1995. These yield figures, however, mask the increasing qualities required of these lighter fuels. Additional gasoline blending stocks will be needed to maintain higher octane ratings as lead additives are phased down. In addition, the increased use of distillate fuel oil as a transportation fuel will require increasing attention to the cetane ratings of distillate output.

Of special concern is the decreasing API gravity and increasing sulphur content of crude oils coming to the market. Low-gravity crude oils generally contain lower proportions of the lighter hydrocarbon compounds that make up the lighter products. Thus, to meet a given or increasing level of demand for these products, additional investment is necessary in "downstream" equipment to "crack" and reform hydrocarbon molecules associated with heavy products into higher octane blend stocks. Increased investment in thermal and hydrorefining processes will be needed to enhance diesel fuel quality.

The startup of Alaskan North Slope oil production in 1977, which now displaces 1.64 million barrels per day of imports, contributed to this decline in average quality. North Alaskan crude has a gravity of 27 degrees API, compared with the average gravity of about 33 degrees API for all crude oil run through U. S. refineries in 1983. The decline in crude oil consumption since 1978 has come almost entirely out of imported oil, and decreasing U.S. purchases of high quality OPEC oils have absorbed a disproportionately large share of this import decline. So, with the projected recovery in total imports, a rebound in OPEC sales would be expected to moderate the recent decline in the average quality of available crude oil. The longer term trend in crude oil quality, however, is still downward.

Downstream investments by domestic refiners in recent years have also increased the flexibility of many firms to pick and choose among crude oil types. The market position of countries producing the higher quality crude oils has been weakened, and, as a result, the quality-related price differentials between crude oils have narrowed.

Petroleum Inventories. Domestic petroleum demand can be met from combinations of three basic sources: current domestic production, current imports, or the drawdown of petroleum product inventories. The levels of inventory that are considered to be optimal and the decision to draw on or build stocks are determined by the operating requirements of the industry, the need to accommodate periodic increases in consumption levels beyond production capabilities, and any hedging or speculative response to changing oil prices and supply uncertainty.

From 1981 to 1983, declining operating levels, the development of excess peak-season refining capacity, high real interest rates, surplus world oil production capacity, and declining oil prices combined to cause lower optimal levels of refined product stocks. These factors influenced primary stocks (held at refineries, bulk terminals, and in pipelines) as well as secondary and tertiary stocks (held by local distributors and end-use consumers, respectively). The resulting worldwide stock drawdown, commencing in mid-1981, reduced the demand for currently produced crude oil, putting further downward pressure on oil prices. By the end of 1983, this extended stock drawdown appears to have been completed. Over the forecast period, normal current estimates of days' supply are assumed to continue and as a result demand increases are accompanied by stock building.

Natural Gas

The market for natural gas--the principal fuel used by the residential, commercial, and industrial sectors--is currently undergoing a major transition. From the 1930's to the late 1950's, natural gas went from being a little-used waste byproduct of oil production to providing a quarter of U.S. energy consumption. By the early 1970's, natural gas was being delivered to users at prices well below those of competing petroleum products. Prices paid to gas producers by interstate purchasers were held at low levels by regulations and long-term contracts. As a result, the amount of gas demanded was greater than production.

There is substantial uncertainty about the near-term and long-term outlook for natural gas prices and consumption. Since the enactment of the Natural Gas Policy Act of 1978 (NGPA), natural gas prices have risen rapidly. Gas consumption has declined in each year since 1980 under the combined influence of rising gas prices, a weak economy, warm winters, and, since early 1981, falling oil prices. While gas prices are currently under downward pressure, because gas-producing capacity is well in excess of consumption, the price ceilings on a large share of U.S. gas production are to be removed, under the NGPA, at the beginning of 1985. Adjustments to the current market pressures on gas may be slowed somewhat by the regulatory and institutional structure of the natural gas industry (see following box).

Structure of the Natural Gas Industry

Although natural gas flows continuously from wellhead to burner tip in an interconnected network of pipes, the ownership of gas typically changes at least three times before it is consumed. Gas is sold by well owners or leaseholders to the (long-distance) transmission company ("pipeline"). Sometimes these sales are made through gathering companies that operate systems for collecting gas from the wells in a producing area. (About two-thirds of the gas in this country is produced in Gulf Coast States.) Pipelines sell most of their gas in "city-gate sales" to natural gas distribution companies, which are regional monopolies subject to regulation by State public utilities commissions (PUC's). Distribution companies then sell gas to end users. Both city-gate sales and the wellhead purchases of gas for city-gate sales are subject to regulation by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act of 1938 and to a lesser degree under the Natural Gas Policy Act of 1978.

Natural gas consumers can be grouped into two categories:

- Residential, commercial, and industrial users who would have to incur relatively large capital costs in order to switch to alternate fuels--for these users, near-term gas consumption is relatively insensitive to price.

- Large industrial consumers and electric utilities that have the capability to burn competitively priced alternative fuels--for whom gas consumption is relatively sensitive to price.

Recent Developments Affecting the Outlook for Natural Gas

While oil prices have recently been stable or falling, the price of natural gas rose rapidly up to 1983. From 1978 to 1983, the average real wellhead price of gas increased 98 percent, continuing the upward trend started in the mid-1970's. These price increases have occurred despite stable or even declining consumption. The reasons for the recent price increases are related to the long history of natural gas regulations, to certain types of contractual relationships developed under those regulations, and to decisions to buy long-term supplies of gas which seemed sound when they were made. Gas market response to declining consumption has, however, contributed to the recent stabilization of prices.

In the mid-1970's, the interstate gas market (which trades gas bought principally for resale by pipeline companies that move gas from producers in one State to regional distribution companies and consumers in other States) was characterized by supply shortages and resulting consumer curtailments. Interstate pipelines could not obtain the amount of gas their customers demanded at the price the Federal Power Commission (now the Federal Energy Regulatory Commission (FERC)) permitted them to pay. The intrastate markets, which were not Federally regulated, had plentiful gas, albeit at higher prices.

The Natural Gas Policy Act (NGPA) of 1978 (P.L. 95-621) established a new pricing structure, putting most gas from currently producing wells under price ceilings based on geology, distance from other wells, location, depth, and existing contractual arrangements for the gas (see following box). In addition to extending Federal regulation of wellhead prices to intrastate, as well as interstate, natural gas, the NGPA also created a category of high-cost gas (Section 107), most of which is free from price ceilings.

Wellhead Price Regulation Under NGPA

The Natural Gas Policy Act of 1978 (NGPA), signed into law on November 9, 1978, mandated a new framework for the regulation of wellhead prices of natural gas. The Federal Energy Regulatory Commission (FERC) was granted jurisdictional authority over virtually all natural gas production, both interstate and intrastate. The NGPA established a complex schedule of wellhead prices. The maximum price a producer could receive was based upon the depth and other physical characteristics of the well, proximity to other wells, whether the gas was sold in the interstate market on or before November 8, 1978, the date the well began producing and the type of deposit being produced.

In general, reserves are divided into old interstate, old intrastate, and new gas reserves. Most old reserves, established prior to 1977, are governed by Sections 103, 104, 105, or 106 of the NGPA. The ceiling prices are determined by well proximity, contract provisions, and geologic formation and are further adjusted by a periodic inflation factor. The interstate gas covered by Sections 104 and 106 is never decontrolled, production from 103 wells less than 5,000 feet deep is decontrolled on July 1, 1987, and the remaining gas from old reserves is decontrolled on January 1, 1985.

In order to be classified as a Section 102 well, an onshore well started after February 19, 1977, must produce from a new reservoir or be at least 2.5 miles from or 1,000 feet deeper than any commercially producing well. Offshore gas is qualified for 102 status if production is from new leases or reservoirs discovered after July 27, 1976. Almost all 102 production is decontrolled on January 1, 1985 and, until then, its ceiling price is adjusted by both monthly inflation and escalator factors.

Section 107 production includes gas produced from wells deeper than 15,000 feet drilled after February 19, 1977, or from geopressured brine, coal seams, Devonian Shale, or tight sands or under other conditions determined by FERC to present extraordinary risks or costs. Tight sands or "extraordinary risk" production is regulated; all other 107 gas was deregulated on November 1, 1979.

Pipeline companies which had been unable to obtain sufficient supplies under previous regulations and had commitments for low-priced gas that would keep their average cost of gas low bid readily for the decontrolled gas. Numerous contracts were signed that required most of the gas to be paid for even if not taken by the pipeline.

Five factors have contributed to recent gas price increases:

1. The older, lower cost fields are slowly being depleted and, as a result, higher cost new gas is becoming a larger fraction of gas supply.
2. The price of some new gas is allowed to increase faster than the rate of inflation.
3. Very high prices were paid for some deregulated natural gas.
4. Contracts signed after passage of the NGPA require pipeline companies to take most of the higher cost gas covered under the contract, with the result that some pipelines buy less low-cost gas when consumption falls.
5. Price controls on the old gas discourage production of supplies for which costs exceed the price ceiling.

The market has responded to these gas price increases, the economic recession and decline in industrial activity, and falling world oil prices by decreasing gas consumption each year since 1980. As a result, since early to mid-1983, pipelines have found themselves with more gas than they can sell. For those pipelines in the position of defaulting on take-or-pay commitments, declining consumption means even higher prices, thus exacerbating the problem.

Price Flexibility in the Wellhead Market. In response to the current excess supply of gas, pipelines have taken a number of steps to reduce the prices they pay for gas at the wellhead. These actions fall into three areas: exercise of market-outs, renegotiation of contracts, and advancement of novel legal theories to abrogate contracts.

First, pipelines are exercising contract provisions, "market-out" provisions, that allow a buyer to terminate a contract if the buyer cannot market the gas. Some pipelines have lost reserves when the seller exercised the complementary option to find another buyer, but, in most cases, producers have agreed to lower prices. Market-outs have been particularly effective in reducing prices paid for high-cost (Section 107) gas and in providing leverage for renegotiation of take-or-pay provisions.

Second, many pipelines have been successful in renegotiating contracts to achieve temporarily lower prices, lower take-or-pay requirements, or both. But, in a large number of cases, pipelines and producers have not reached an agreement, and pipelines have unilaterally reduced prices or receipts from producers' "takes" below contracted levels. As a result, lawsuits have been filed against several interstate pipelines by many major and independent producers.

These lawsuits and, more generally, the question of how rapidly and completely existing contracts can be altered to reflect new market realities--still represent a major problem in analyzing wellhead markets. The take-or-pay liabilities at issue could represent 40 percent or more of the equity capital of interstate pipelines and thus carry the potential for severe effects on the market. In this analysis it is assumed that all unilateral actions by pipelines to reduce gas purchases or prices, as reported by the American Gas Association in March 1984, remain in effect. This is not a prediction of the outcome of the lawsuits filed by producers, but is in line with EIA's practice of assuming that current policy continues through the forecast period.

The resolution of these suits may take considerable time, and it is uncertain who will bear these potential liabilities--the pipelines or their customers. Ironically, new gas can be purchased today at a price that would lower the average cost of gas to some pipelines--but many cannot take advantage of this situation since it would cause additional take-or-pay liabilities.

As well as lowering prices, terms of new contracts are showing more flexibility in pricing and delivery. For instance, recent contract activity in the Outer Continental Shelf (OCS) points to more market-outs, with the percentage of contracts with market-outs rising from 36 percent to 85 percent between 1981 and 1982 (Table 16). The percentage of contracts with take-or-pay levels above 75 percent also fell from 97 percent to 75 percent. Although an increasing number of contracts contained escalators tied to oil prices, the potential impact of indefinite escalators is lessened by the increasing adoption of market-out provisions.

In summary, pipelines realized in early 1982 that they had purchased more gas than needed and, in doing so, had paid too high a price. From then until late 1983, pipelines exercised market-out contract provisions when possible to bring down the price of purchased gas. However, some gas today remains priced at more than $9 per million Btu compared to an average new-contract price of $3.00 to $3.50 per million Btu. Furthermore, even though gas under new contracts is selling for less than the new gas price ceilings, existing Section 102 gas contracts have shown virtually no downward price adjustments. As a result of this activity, changes in purchase strategy, contract adjustments, and the rapid drop in new gas prices, the average wellhead price of natural gas has been essentially constant for most of 1983.

Table 16. Summary of Major Provisions in Recent Contracts Covering Section 102 Outer Continental Shelf Gas Filed at the Federal Energy Regulatory Commission (Based on Percentage of Number of Contracts)

Summary	Contract Year 1981	1982
	(number of contracts)	
Number of Contracts	41	72
	(percent)	
Percent with Take-or-Pay Greater Than 75 Percent	97	75
Percent That Reference Number 2 Fuel Oil	36	47
Percent That Reference Number 6 Fuel Oil	7	11
Percent with Market-Out of Pricing Provisions	36	85
Percent with Price Redetermination at an Interval of 1 Year or Less	83	92
Percent of Contracts with Terms for Less Than 15 Years	5	3

Source: Contracts on file at the Federal Energy Regulatory Commission as reported in Energy Information Administration, Structure and Trends in Natural Gas Wellhead Contracts, DOE/EIA-0419 (Washington, D.C. 1983).

Sales to Large Gas Consumers. In the last few years, the workings of the natural gas market have become more flexible by matching sellers and buyers through direct sales or contract carriage proposals. Through the use of such industrial sales programs (ISP's), producers facing cutbacks or shut-in production are matched with consumers who would switch out of gas if faced with prices calculated under a pipeline's ordinary tariff. These programs offer gas at lower rates to customers with dual-fuel capabilities.

In one form of the program, the pipeline determines the price at which its distributors can sell gas to dual-fueled customers, and nets out its transmission cost to arrive at a wellhead price it can afford to pay. The pipeline then offers this price to producers who have contracted to sell gas to the pipeline and agree to release the pipeline from its take-or-pay obligations under their contract. In a second type of program, a contract carriage program, the pipeline agrees to transport gas purchased directly from a producer by an end user or a distribution company.

The FERC (or "the Commission") has imposed conditions on these programs to ensure that they result in lower prices to consumers not offered gas under the ISP's. The Commission has prohibited pipelines from using the programs to serve customers who are part of a pipeline's "core" market, that is, customers who would continue to use gas even if charged a pipeline's full tariff. Eligible customers are limited to those who have not previously been served by natural gas, and to those who currently buy gas directly from producers, are capable of burning alternate fuels, or who buy gas from a pipeline at a discount rate, including interruptible rates.

The Commission also requires that the price of gas sold under these programs must equal or exceed the weighted average cost of gas to the pipeline, and requires that gas sold under the programs be credited against the pipeline's take-or-pay obligations and the distributor's minimum bill obligations.

Proposals for a form of contract carriage offer some promise of introducing greater flexibility and competition into the entire system. Currently, the vast majority of interstate natural gas is bought at the wellhead by pipelines and then resold, either to gas distribution companies under tariffs regulated by the Commission or to large users under unregulated direct sales. The take-or-pay provisions of contracts between producers and pipelines are often mirrored by minimum bill provisions of pipeline tariffs or analogous "demand" charges. Purchased-gas costs incurred by pipelines are flowed through directly to distributors.

As a result, one pipeline makes gas purchases and other strategic decisions that determine the conditions under which all its customers obtain gas. The decisions of the pipeline may be "best" for the pipeline but cannot be "best" for each distributor on the system. A pipeline's take-or-pay commitments, for example, represent a price-versus-risk decision that is passed on to all customers, even though some may prefer less assured supply to obtain a lower price, while others might prefer the opposite.

An alternative system, "contract carriage," would allow distributors and large gas consumers to buy gas at the wellhead, either on a spot or a contract basis, and pay a pipeline to transport the gas. By allowing distributors to purchase gas and negotiate for tailored tariffs, contract carriage may allow for the possibility of more efficient operations, but places additional risk on the distributor. However, many distributor contracts include minimum-bill provisions and require distributors to purchase or pay for gas delivered to a specific area from one pipeline. Moreover, contracts that guarantee producers high takes from pipelines reduce the amount of gas available for direct sale, further limiting the ability of distributors to arrange direct purchases. Contract carriage can increase competition and flexibility only if these constraints, inherited from an era of wellhead price regulation, are removed.

<u>Pricing Flexibility at the Distributor Level</u>. Many State regulatory commissions have, in the past year, allowed flexible pricing by gas distributors, a form of pricing under which distributors may lower prices to some customers in order to be competitive with fuel oil. When these competitive prices are below fully allocated costs, a few commissions have allowed distributors to recoup losses by raising prices to residential customers and others unable to switch fuels readily.

When the price of natural gas rises above the alternative fuel price, consumers able to burn an alternative fuel can be expected to do so. Because the distributor's total cost-of-service consists of mostly fixed and joint costs, in the short term the distributor could, in principle, reduce the price of gas to the level of short-run marginal costs without causing the other users to cross-subsidize the users that have alternative fuels. However, many distributor contracts include minimum bill provisions or demand charges requiring payment for gas whether or not it is delivered, and therefore short-run marginal costs may be considerably below purchased gas commodity charges. The regulatory dilemma is whether to allow one class of customers to bear a portion of the cost of purchasing gas destined for another class or to limit the ability of distributors to spread their fixed costs over the largest possible volume of sales.

It may be to the benefit of the other users for the gas users with duel-fuel capabilities to remain on the system since they will continue to bear a portion of the system's fixed costs. Of course, if the remaining users are stimulated into switching or additional conservation by the rising prices, the distributor may be forced to either cut costs or accept a lower rate-of-return. Because most end users are not contractually obligated to buy the gas, distributors may not be able to earn their full allowed rate-of-return. How these nominally "captive" consumers will respond to higher prices is an unresolved uncertainty about the extent to which flexible pricing can stabilize gas markets and sustain demand.

It appears that many State commissions have allowed distributors to begin attempts to keep dual-fired customers from switching; several States have established flexible tariffs. In this analysis, it is assumed that flexible pricing is allowed and that about 50 percent of the cost not recovered from dual-fired users by large distributors is reallocated to users without dual-fired capabilities. Other actions have been proposed. In general, State commissions have recognized the desirable effects of maintaining switchable loads. The success of their efforts will largely depend on the relationship of purchased gas costs to the alternate fuel price, because this relationship controls the ability to reduce tariffs, maintain load, and meet costs.

These programs represent a departure from the regulatory philosophy of the 1970's, when gas use was being curtailed and there was no significant competition with alternative fuels in many areas. The longer term impacts on the equity owners and ratepayers is difficult to assess. Taken together, the actions seem to have arrested both the increase in gas prices and the erosion of gas markets. The levelling off of wellhead prices, industrial sales programs, and flexible pricing by distributors appear to have recaptured consumers that have the capability to switch from gas to fuel oil.

Contract Provisions. Contracts in effect in 1980 for gas which is currently price-controlled are divided between those containing clauses specifying "definite only" pricing and highest allowed regulated rates, based on data from Form EIA 758. Prices for "definite only" come from Form EIA 758, and gas priced under a highest allowed regulated rate receives the NGPA ceiling price. A number of different provisions specify the price upon deregulation.

Definite price escalators provide for a fixed increase in the price of gas each year. Oil parity clauses tie the escalation in the gas price to the Btu-equivalent price of crude oil or a refined petroleum product, usually distillate or residual fuel oil. Relatively few contracts have oil parity clauses, but the importance of these clauses is magnified by a third type of deregulation clause: most-favored-nation clauses.

There are two types of most-favored-nation clauses: two-party and third-party most-favored-nation clauses. Two-party clauses specify that the price of gas escalates to the highest price paid under any contract by the same buyer. Third-party most-favored-nation clauses, which are far more numerous, specify that the price of gas will escalate to the highest price, or an average of the two or three highest prices, paid by any buyer in an area. Thus, if one or more of the contracts in an area contains an oil parity clause, the price of all gas in that area under contracts containing third-party most-favored-nation clauses will escalate up toward the oil parity price, because an oil parity contract will ordinarily be one of the highest priced contracts.

Many contracts with oil parity or most-favored-nation clauses do not provide any relief for the buyer if the gas proves unmarketable at the escalated price. However, as a gas surplus became more apparent in the early 1980's, many pipelines began to include market-out provisions in their contracts, and this analysis assumed that all contracts signed in or after 1981 include market-out provisions. Under a market-out clause, a pipeline can refuse to take delivery of gas it cannot market, but the producer has the right to seek alternate buyers. This analysis assumed that gas covered by market-out clauses would be priced at the market price for new gas supplies; for, if the pipeline offered lower than market prices, the producer would sell the gas elsewhere; while, if the producer demanded higher than market prices, the pipeline could release the gas and obtain alternate supplies.

Natural Gas Policy Act and Contract Assumptions for the Midprice Case

When gas under existing contracts is decontrolled, most contracts with highest allowed regulated rates provide for alternative pricing clauses upon deregulation. Information on deregulation pricing from the EIA-758 is taken into account and the contracts are divided into five categories: fuel-oil-parity clauses, most-favored-nation clauses with and without market-out provisions, all other deregulation clauses, highest-allowed regulated rate with no deregulation clauses, and "definite only" pricing.

Upon decontrol, gas covered under contracts with oil-parity clauses and no market-out provision is assumed to receive a price that escalates to 110 percent of the price of distillate fuel oil. Gas sold subject to most-favored-nation clauses with no market-out provisions receives the oil-tied price with a 1-year lag. All other deregulated gas is assumed to receive the new contracts price in the first year with the price adjusted in following years according to the movement in the new contracts price each year.

Post-1980 contracts for gas under pricing controls are assumed to be priced at the lower of either the highest allowed regulated rate (and receive the NGPA ceiling price until decontrol) or the market-clearing price for new contracts. All new contracts for gas not under pricing controls receive the market-clearing price.

In this analysis, it is assumed that all contracts signed in or after 1981 include market-out provisions. Under a market-out clause, a pipeline can refuse to take delivery of gas it cannot market, but the producer has the right to seek alternate buyers. This analysis assumed that gas covered by market-out clauses would be priced at the market price for new gas supplies; for, if the pipeline offered lower than market prices, the producer would sell the gas elsewhere, while if the producer demanded higher than market prices, the pipeline could release the gas and obtain alternate supplies.

Take-or-pay requirements for any new contract (post-1980) are assumed to be 75 percent of deliverability. For contracts in effect in 1980, pipeline take-or-pay percentages are assigned to each category of gas using the EIA-758 data.

This study assumes flexible pricing by distributors is allowed for industrial and electric utility gas users that can switch to oil. If the usual calculated tariff to these users results in the price being higher than the parity price of residual fuel oil, these consumers are assumed to receive gas prices set at this parity price, as long as the prices to these customers are not reduced below 95 percent of the purchased gas costs. When prices to these customers are reduced, half of the revenue loss by large distributors is passed to gas users that do not have the option of switching to oil.

The Near-Term Outlook for Natural Gas

Although the NGPA decontrols about half of the natural gas supplies in 1985, this does not mean that prices for the decontrolled gas will be determined solely by market forces. Most gas is sold under long-term contracts and the NGPA does not release pipelines from the contracts. Thus, the prices paid in 1985 will be determined by these contract provisions, as well as supply and demand forces. Most gas scheduled to be decontrolled in 1985 is covered by Section 102 of the NGPA and is priced according to contracts calling for the maximum regulated rate, i.e., the NGPA Section 102 ceiling price. Thus, whether the price of this gas goes up or down in 1985 depends on whether the decontrol provisions in the contract provide for prices in 1985 that are higher or lower than the 1984 Section 102 price ceiling.

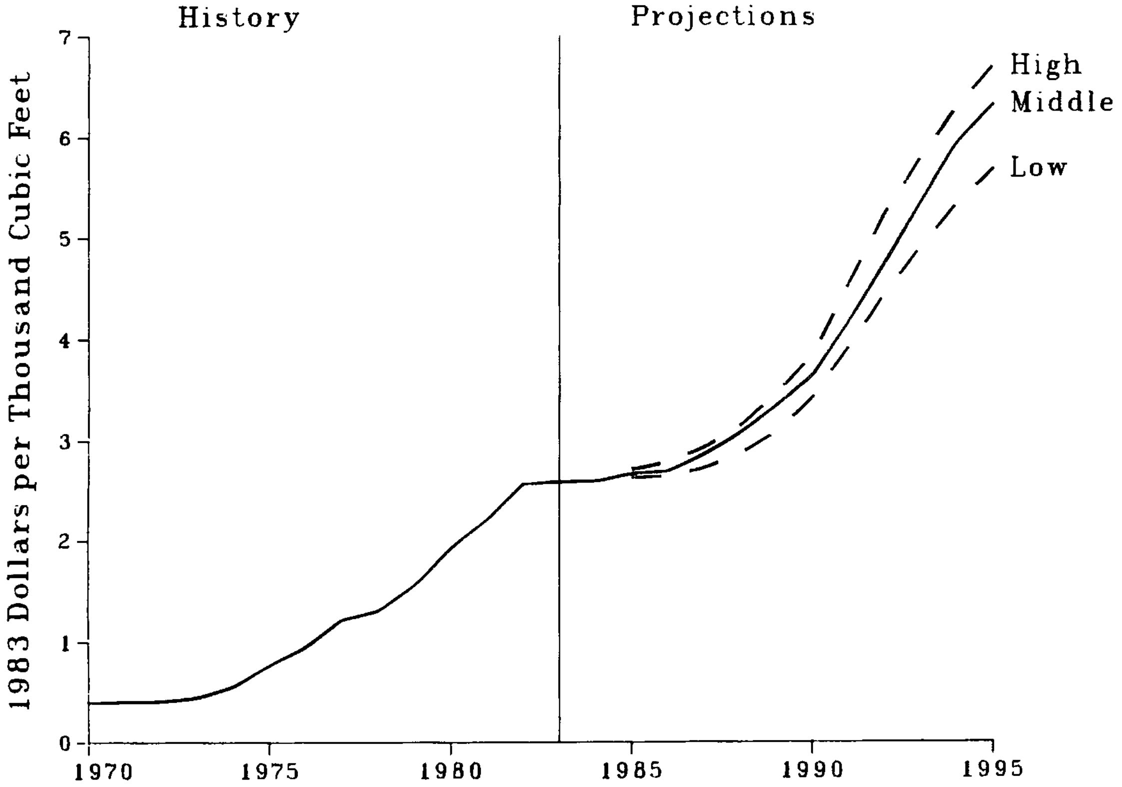
At this time, no major price increase is projected to occur in 1985, because the market price of gas in 1985 is projected to be substantially below the 1984 price ceilings for 102 gas. Thus, the price of gas under contracts with market-out clauses is projected to decline in 1985. However, the price of number 2 fuel oil in 1984 and 1985 is projected to be substantially higher than the 1984 Section 102 price ceiling. Therefore, the price of gas under contracts with oil parity or most-favored-nation clauses is expected to increase sharply in 1985. The net effect of the changes due to decontrol, the continuing depletion of low-priced old gas supplies, and the addition of new gas reserves is projected to be a slight increase in the national average wellhead price of gas (Figure 28).

The effect on individual pipelines may differ significantly, however. Pipelines with a majority of market-out clauses are projected to experience a decline in their purchased gas costs, while pipelines with many oil parity or most-favored-nation contracts are expected to experience substantial increases.

While average natural gas wellhead prices are expected to remain relatively stable in 1985 and 1986 and some pipelines will experience declining gas costs, all pipelines are expected to face rising gas costs in the late 1980's and 1990's for several reasons (Figure 29). First, contracts for price-controlled "old" gas will be expiring. Second, the depletion of shallow, inexpensively produced gas reserves will require producers to drill more marginal or more expensive sources of gas such as tight sands, deeper wells, and enhanced gas recovery. Obtaining gas from these sources will require higher prices to compensate producers for increased cost and risk. Third, an expanding population and growing economy will tend to increase the demand for gas and thus push up the price. Fourth, world oil prices are projected to resume rising in the late 1980's.

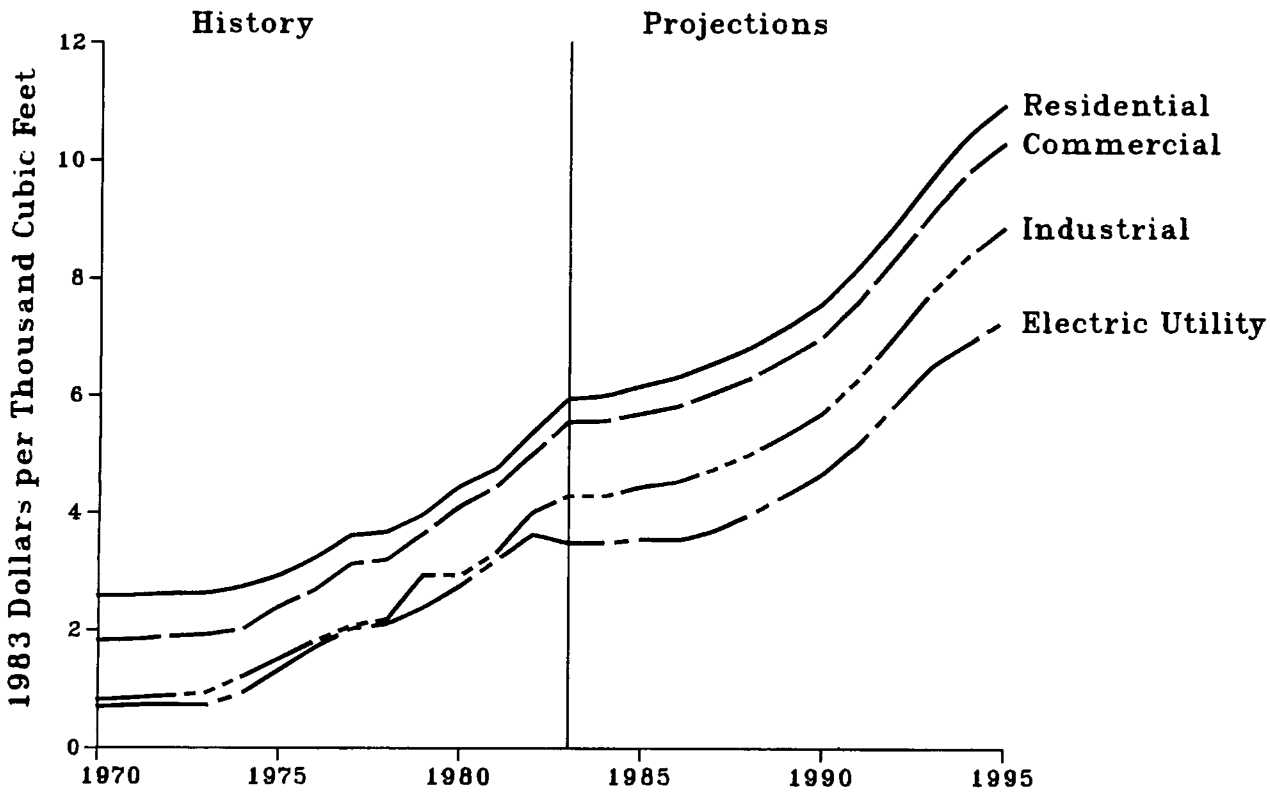
Effect of World Oil Prices on the Natural Gas Market. Many analyses of natural gas markets assume that the price of natural gas in an unregulated market would always be priced at the Btu-equivalent of oil, or at some fixed percentage of Btu-equivalence with oil. This argument is based on the important connections between the price of oil and the price of gas. First, many industrial and utility consumers have the ability to burn either oil or gas. Therefore, if the price of gas rose above the price of oil, massive switching from consumption of gas to oil could be expected to occur, which would tend to bring the price of gas down. Second, gas and oil exploration compete for much of the same drilling equipment and personnel, so that a fall in the price of gas would divert resources from gas

Figure 28. Average Wellhead Price of Natural Gas Production High, Middle, and Low Price Scenarios, 1970 to 1995



Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83); Natural Gas Annual, 1982, DOE/EIA-0131(82) (Washington, D.C., 1983).

Figure 29. Natural Gas Prices by Sector, Midprice Scenario, 1970 to 1995



Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83); Natural Gas Annual, 1982, DOE/EIA-0131(82) (Washington, D.C., 1983).

exploration to oil exploration, thereby lowering the supply of gas and driving up the price. Third, some gas contracts explicitly tie the price of gas to the price of oil.

Although there is some validity to these arguments, the conclusion that gas prices move in lockstep with oil prices is a gross over-simplification. First, while gas and oil compete for drilling equipment and personnel, this does not mean that the wellhead prices must be equal. Each drilling prospect differs in the expected costs of drilling, the probability of finding oil or gas, and the amount of oil or gas expected to be found. Even if the price of oil rises more rapidly than the price of gas, some gas prospects will still be more attractive than oil prospects because of a higher probability of finding gas, lower drilling costs, or a larger expected quantity of gas. It is more accurate to conclude that, although the price of gas would be pushed up to some extent, it may rise only enough to establish a new equilibrium at a price per million Btu below that of oil.

Further, although many industrial and utility users can use both oil and gas, this does not establish any fixed relation between the national average price of oil and the national average price of gas for several reasons. First, the transportation costs of gas differ from those of oil. However, the majority of domestic gas supplies are produced in the Southwest and, in an unregulated market, all pipelines would have to pay comparable market prices for gas. Because transportation costs to different regions differ widely, the delivered price of gas would necessarily differ from the price of oil in most regions. Thus, there is no single wellhead price of gas that would result in a delivered price of gas equivalent to oil in all regions.

Furthermore, depending on the type of equipment installed and environmental restrictions, dual-fired consumers may be able to burn high-sulfur residual, low-sulfur residual, or distillate fuel oil. Delivered prices of these different oil products can vary by several dollars per million Btu. Thus, gas does not compete with only a single grade of oil, but with a range of oil products with widely differing prices.

Also, the new flexible tariffs introduced by many State PUC's mean that the price of gas to dual-fired users can be kept at or below the price of oil for a wide range of oil and gas prices to prevent switching. However, this means that additional fixed costs must be borne by other consumers without dual-fuel capability, and it is further assumed that prices to dual-fired users would not be reduced more than 5 percent below the distributor's price of gas. Thus, flexible tariffs do not necessarily avoid all switching by dual-fired consumers.

Finally, although some gas contracts explicitly tie the price of gas to the price of oil, the resulting prices do not necessarily reflect the value of the gas in an unregulated market. Many of these oil parity contracts provide for gas to be priced above the price of distillate at the wellhead. The delivered price of the gas would be more expensive than that of alternate fuels if the pipeline were not able to average in the cost of the gas with low-cost regulated gas. However, these oil parity contracts, together with most-favored-nation contracts which are triggered by the oil parity contracts, do tend to push up the price of gas when the price of oil rises.

In summary, a rise in oil prices can be expected to trigger a rise in gas prices due to intensified competition for drilling equipment and personnel, less fuel-switching by dual-fired customers, and gas contracts that tie the price of gas to the price of oil. However, the rise in gas prices will not, in general, be equal to the rise in the price of oil and will not be any fixed percentage of the price of oil.

Instead of concluding that a rise in oil prices translates exactly to a rise in gas prices, one concludes that rising oil prices will force gas prices to reach some new equilibrium price based on the complex supply and demand factors at work in the gas market. In fact, due to flexible distributor tariffs instituted by some State PUC's, the impact of higher oil prices may be to lessen the tariffs paid by users without dual-fired capability.

Natural Gas Midterm Projections

Midterm Trends. Across all scenarios, gas prices are expected to rise significantly by the late 1980's, due to the expiration of low-cost price-controlled gas contracts, depletion of the shallow, conventional gas fields, a growing population and expanding economy, and rising oil prices. The expiration of the low-cost contracts and depletion of low-cost fields contribute to the projection that, in all scenarios, gas prices will rise more rapidly than oil prices between 1990 and 1995. An additional contributing factor to the rapid increase is the need to acquire more expensive, new reserves as the gas surplus of the mid-1980's ends.

These projections may be excessively pessimistic. A number of factors not assumed in the forecast could mitigate the gas price rise: additional imports from Canada or Mexico displacing more expensive domestic gas, more rapid development of exotic or deep sources of gas, increased production of associated gas if domestic drilling activity intensifies, or the beginning of gas production from Alaska's North Slope.

Effects of World Oil Prices. As shown in Figure 28, average wellhead prices rise significantly more rapidly in the high world oil price scenario than in the mid and low world oil price scenarios.

In the mid- to late 1980's, a significant factor in the high world oil price scenario is oil parity and most-favored-nation provisions in gas contracts. By the 1990's, these contracts are less significant, since all contracts signed in 1981 or later are assumed to have market-out clauses and thus will escalate with the market price for new gas reserves, not with the oil price. However, two factors tend to push up gas wellhead prices more rapidly in the high world oil price scenario. There is far less fuel-switching out of gas in the high world oil price scenario, and therefore utility demand is far higher than in the low world oil price scenario. Also, intensified competition with oil for drilling resources leads to higher wellhead prices in the high world oil price scenario.

The difference in wellhead gas prices between the high and low world oil price scenarios is not nearly as large as the difference in the world oil prices. For example, in 1995, oil prices in the high world oil price scenario are 80 percent higher than in the low world oil price scenario but gas wellhead prices are only 18 percent higher, for several reasons. First, under any scenario, there exist large gas reserves from tight formations or deep wells and reserves recoverable using enhanced recovery techniques. Higher trends for world oil prices will make these sources economically competitive. Second, increased drilling for oil stimulates increased production of associated gas in the high world oil price scenario. Third, lower economic growth in the high world oil price scenario reduces residential, commercial, and industrial gas demand below the levels in the low world oil price scenario.

Utility Gas Consumption. The effect of wellhead prices on delivered prices to consumers varies dramatically across the scenarios. Utility prices vary far more than residential prices between the high world oil price and low world oil price scenarios, because of the flexible tariffs for dual-fired users assumed to be adopted by many State PUC's. In the low world oil price scenario, utility commissions are assumed to reduce tariffs dramatically in an attempt to avoid switching, and therefore residential customers must bear a greater share of fixed costs. The result, in the low world oil price scenario, is that residential prices rise more rapidly than they would if customary tariffs were maintained, while utility prices rise less rapidly. Conversely, in the high world oil price scenario, it is assumed to be unnecessary for PUC's to reduce tariffs as much to dual-fired customers since gas appears less expensive relative to oil. The result is that utility prices in the high world oil price scenario in 1995 are 31 percent higher than in the low world oil price scenario, while residential prices are only 12 percent higher.

Utility consumption of natural gas varies widely depending on the world oil price assumptions. Despite lower economic growth, utility demand for gas in the high world oil price scenario is higher than in the low world oil price scenario, primarily because many utilities switch from gas to oil in the low world oil price scenario. In the low world oil price scenario, wellhead prices of gas are much closer to the price of oil than in the high world oil price scenario and, after pipeline tariffs are added to the wellhead price, the price to distributors is still well above the price of competing fuels. Because of the assumption that the price to dual-fired consumers would not be reduced more than 5 percent below the distributor's average purchased gas cost, the delivered price to those consumers is above the price of competing fuels. Thus, in the low world oil price scenario, there is significant switching out of gas by utilities in all regions of the country; while, in the high world oil price scenario, dual-fired users generally burn gas and utility demand for gas therefore rises rapidly.

The general question of the pricing of natural gas to electric utilities is very much a current issue, and one of the chief sources of uncertainty in this year's projections. Therefore, care must be taken in interpreting the forecasts, particularly in the mid and low world oil price cases. The year-to-year fluctuations in utility demand indicate that the price of natural gas is close to the price of competitive fuels in those years, and thus small differences in delivered prices could result in significant shifts in demand.

This uncertainty in the forecasts of electric utility consumption of gas reflects, to a great extent, the current uncertainty in natural gas markets. A major point of uncertainty is the capability of electric utilities to switch from gas to oil.

Careful examination of the data on utility capacity types and past fuel choice decisions indicates that there is a substantial amount of capacity that can switch fuels. However, the actual decision will be based on the individual utility's perceptions of the longer term benefits and contractual arrangements.

The relative prices of oil and gas to utilities is the second point of uncertainty. It is not known what the effects of flexible gas prices will be or how widespread they will be. The exact price of oil is also not known. However, all evidence points to the likelihood that, sometime during the forecast period, the prices of oil and gas to utilities will be at parity for key regions, leading to a tenuous balance in the markets. This may not happen in exactly those years represented in these forecasts, or be of the exact magnitude estimated, but it will most likely occur.

Sources of Supply

Natural gas production is substantially similar to oil production as described in the previous section. In 1982, 21 percent of gas production was associated-dissolved gas, that is, gas found in the same deposits as crude oil and produced along with the oil. While much gas is discovered by drillers searching for oil, so that increased oil exploration may result in discoveries, natural gas and petroleum exploration and development projects compete for the same drilling rigs and other capital equipment. These strong interrelationships cause gas supply to be sensitive to world oil prices.

Domestic dry natural gas production in 1983 was about 15.9 trillion cubic feet (or 16.3 quadrillion Btu), about 70 percent from the onshore Lower-48 States and 30 percent from offshore. In addition, net imports provided about 0.9 trillion cubic feet, primarily by pipeline from Canada and Mexico. Domestic proved reserves of natural gas as of December 31, 1982, were 202 trillion cubic feet of dry natural gas, or about an 11-year supply at current levels of production.

Current production comes from proved reserves of gas, which include nonassociated gas (gas from deposits that primarily produce gas) as well as associated-dissolved gas. The costs of recovering proved gas reserves vary greatly because of the location and physical characteristics of the individual reservoirs. For example, a single, large reservoir is generally less expensive to develop per unit of gas produced than would be the case for the same amount of gas scattered in many small reservoirs. In general, yearly additions to proved reserves (excluding reserves found in Alaska) have been smaller than production since 1967. However, in 1981 and 1982--years when gas production was declining--reserve additions were approximately equal to production.

Future production must come in large part from new deposits of gas, which are expected to be deeper, smaller, and more expensive to find and develop than currently producing deposits. Because it cannot be known whether gas (or oil) is present in a formation in quantities sufficient to warrant production until wells are drilled, projections of natural gas production are always subject to considerable uncertainty.

Figure 30 shows recent natural gas production together with projections to 1995. The area indicated as "old" is gas from deposits known and in production in 1977 and included in the lower priced tiers of the NGPA pricing structure. The area marked new gas is largely Section 102 and 107 gas from deposits developed since 1978.

The total production of natural gas is expected to decline from 17.03 trillion cubic feet in 1984 to 16.29 in 1990, then to 14.89 in 1995. This level is down approximately 4.23 trillion cubic feet from the 1978 production. What is particularly important to note is the source of the gas supply. Old reserves are being depleted and new reserves, those developed since 1978, must supply proportionately more of the gas. In 1983, this new gas constituted approximately 23 percent of domestic production. However, it is projected to account for 33 percent of production by 1985, 61 percent by 1990, and 76 percent by 1995. The continuance of domestic production will rely for the most part on the exploration and development of new gas reserves.

In making this supply forecast, it is assumed that the Alaska Natural Gas Transportation System, the proposed pipeline for bringing North Slope gas to the Lower-48 States, will not be in service by 1995. The marketability of the gas has not been proven sufficiently that financing for the entire project can be arranged.

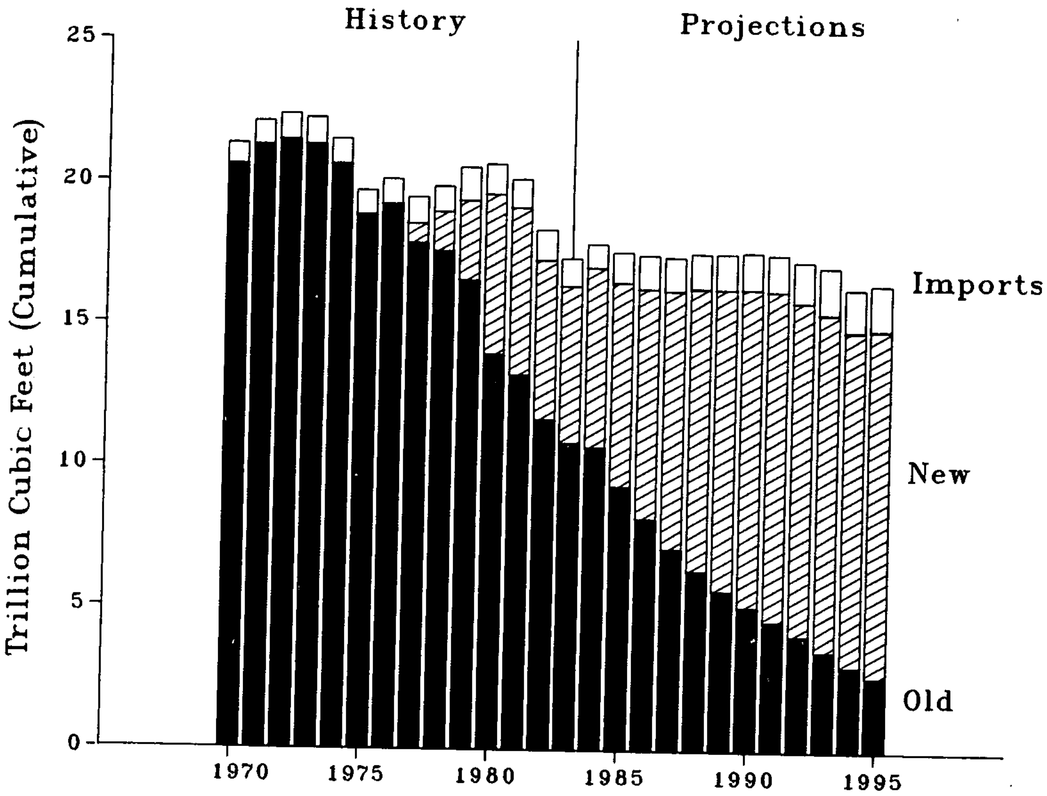
The consumption and production of natural gas are sensitive to the world crude oil price (Figure 31). Higher world oil prices stimulate the exploration and development of both oil and gas reserves and stimulate the demand for gas as a substitute for oil. In addition, the search for oil may result in the inadvertent discovery of gas at the same time that the exploration for oil diverts resources from the search for gas.

Higher production of gas is likely to result from higher prices, which provide an incentive for more costly, new gas reserves to be developed. Figure 28 depicts the wellhead prices of gas under each of the three world oil price paths. In 1995, under the middle world oil price, domestic natural gas production is estimated to be 14.89 trillion cubic feet. However, this estimate declines to 14.49 trillion cubic feet under the low price oil price path but increases to 15.37 trillion cubic feet under the high price path.

These estimates of U.S. gas supply and production are, of course, highly uncertain. Increased development of techniques for producing gas from exotic or deep reserves, the production of Alaskan North Slope gas, and the possibility of augmenting domestic production with increased imports may provide increased supplies of gas without the price rising as rapidly as the projections indicate.

The world oil price also affects the price and production of natural gas through the shifts in end-use consumption. When oil prices rise relative to gas prices, consumers shift from oil to gas, when possible, driving up both the price and production of gas. See the electric utilities section for further discussion of fuel switching in this price sensitive sector.

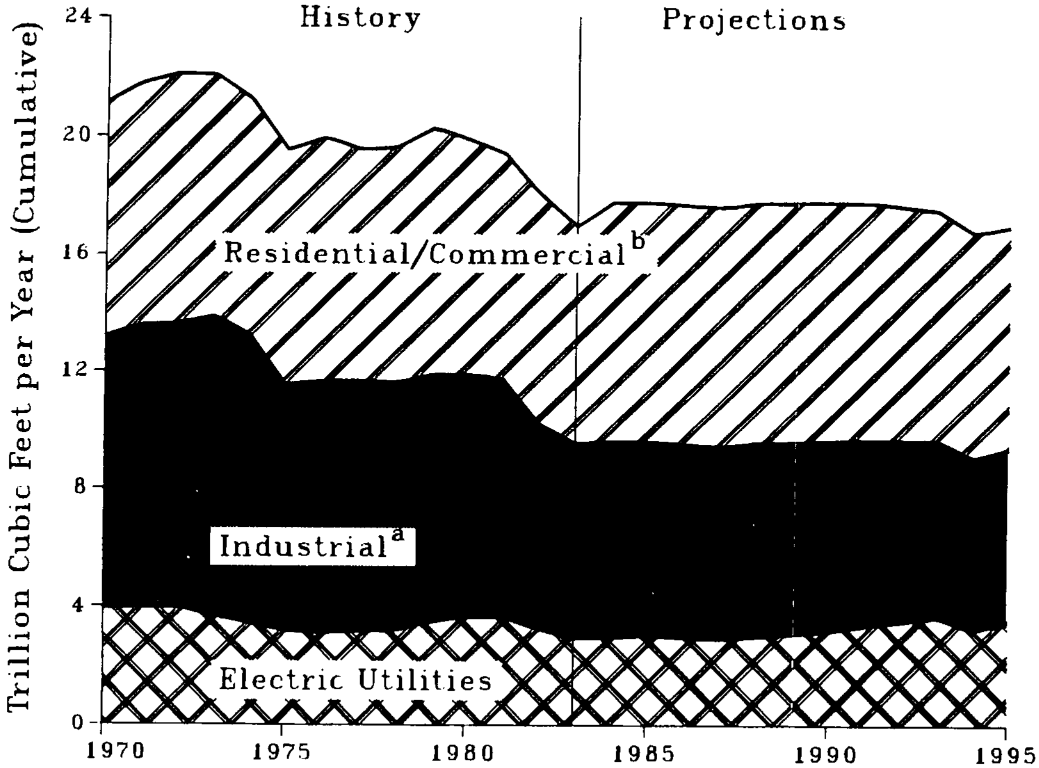
Figure 30. Natural Gas Supply by Source, 1970 to 1995



Note: Natural gas supply includes imports, new gas, and old gas as shown. In the historical data supplementary gas supplies are included in old production because prior to 1980, data are not explicitly available. For 1981 and later years, supplemental gas is included in imports, because it includes a forecasted component that could be imported. New gas is defined as Section 102, 103, and 107 gas under the NGPA. The values for 1980-83 are estimated from Purchased Gas Adjustment data and 1977-79 are projected.

Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); and Monthly Energy Review, DOE/EIA-0035(83)/12[4]); and The Current State of the Natural Gas Market, DOE/EIA-0313 (Washington, D.C., 1982).

Figure 31. Natural Gas Consumption by End Use, Midprice Scenario, 1970 to 1995



[a]Includes lease and plant fuel used in the field gathering and processing plant machinery.

[b]Includes transportation used to fuel the compressors in the pipeline pumping stations.

Sources: Historical data: Energy Information Administration, <u>State Energy Data Report, 1960 through 1981</u>, DOE/EIA-0214(81) (Washington, D.C., 1982); <u>Monthly Energy Review</u>, DOE/EIA-0035(83/12[4]).

Note on Natural Gas Supply/Demand Balance

The projections for natural gas supply and demand for 1995 contain an adjustment entry that equates total projected supply to total projected consumption in that year, and represents unallocated natural gas/distillate-fired gas turbine demand. This adjustment could be met by either increased natural gas production, increased imports, or additional supplemental gas, or distillate. The market price and consumption levels indicated on Table A17 are appropriate. The remainder of the adjustment quantity results from unaccounted for loss, differences in various Btu conversion factors, and associated sectoral definitions, as noted on Table A17.

Coal

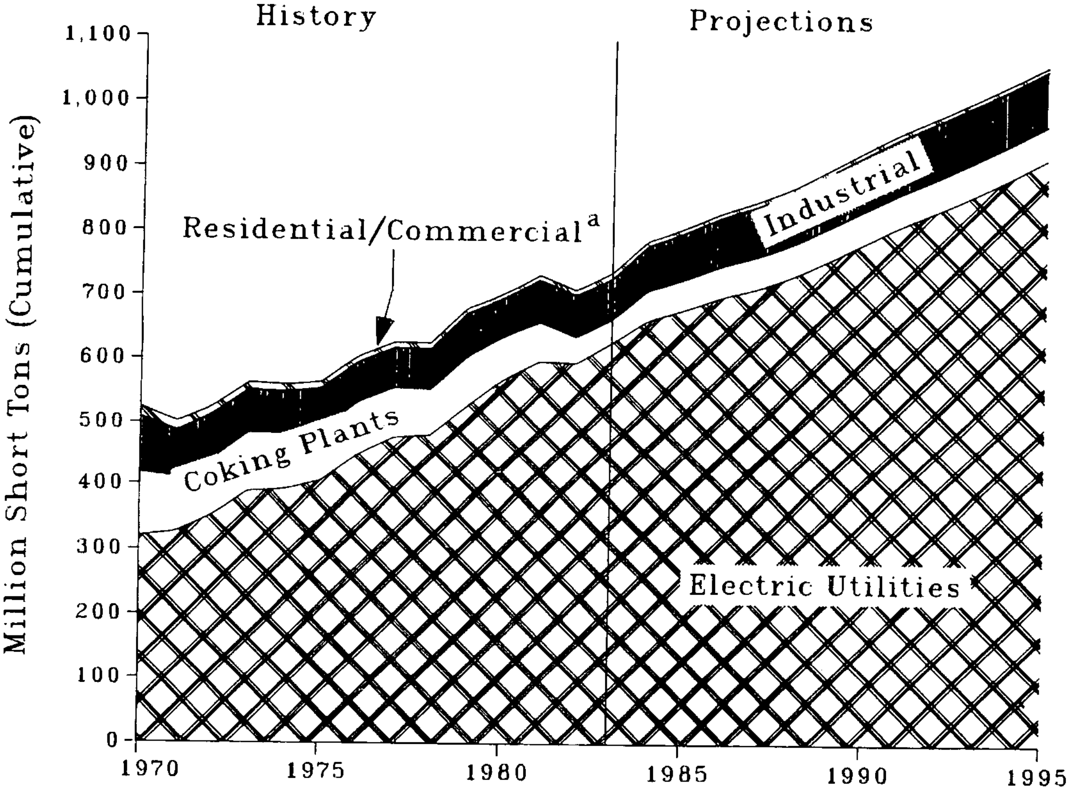
The United States, which recently has turned back to coal as a major energy source, is expected to look even more favorably toward this secure supply of domestic fuel between 1985 and 1995. Coal is expected to meet increased energy demand and to replace other traditional sources of energy that are increasing in price more rapidly than coal throughout the projection period. The rise in coal use was accelerated by the second major jump in oil prices between 1979 and the end of 1980.

As a result of the projected increase in coal demand, coal production is projected to rise from 785 million short tons in 1983 to 1,045 million short tons in 1990, and to 1,191 million short tons in 1995. Western coal production is projected to grow significantly over the projection period. By 1995, about 39 percent of U.S. coal production is forecast to occur in the West, compared with 36 percent in 1983.

Coal, once the predominant fuel consumed in the residential and commercial sectors, was largely replaced in the 1950's by the more convenient fuels--oil, natural gas, and electricity. From 1985 to 1990, coal consumption in these sectors is expected to remain relatively constant at about 7 million short tons per year (Figure 32). Because of the problems associated with the storage and transportation of coal and because of environmental concerns associated with its use, this trend is expected to continue in both sectors.

From 1960 to 1983, coal use declined 33 percent in the industrial sector, which shifted to oil and natural gas because they were inexpensive, clean, and easy to use. The demand for coal in this sector (8.7 percent of all coal consumed in 1983) is projected to increase by about 2.6 percent per year through 1995. This shift in the industrial sector, a sector that consumes energy either as a feedstock or as a fuel to provide energy for combustion, occurs mostly in the major fuel-burning installations where large boilers (greater than 100 million Btu/hour) operate continuously. In these units, the high capital and operating costs associated with coal can be offset by the lower fuel costs. By 1995, the costs of energy from residual fuel oil and natural gas, which compete with coal as boiler fuels, are projected to be about three times higher than from coal. Small boilers (less than 100 million Btu/hour) and industrial-process heaters are expected to continue to use oil and natural gas extensively during this period because it is inefficient for these small boilers to use coal.

Figure 32. Coal Disposition by Sector, Midprice Scenario, 1970 to 1995



[a]Includes transportation in the historical period.

Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); Quarterly Coal Report, DOE/EIA-0121(83/3Q) (Washington, D.C., 1983).

Metallurgical coal used for coking purposes is projected to increase dramatically between 1983 and 1984 from 37 to 46 million short tons. After 1984, consumption is projected to grow at only 0.8 percent per year through 1995 and never returns to the 71 million short tons used in 1978. This rate is considerably below the rate at which steel output is projected to increase. This difference reflects the increased use of electric-arc furnaces as well as continuous casting and steel reprocessing.

Since the 1973 oil embargo, the use of coal and nuclear fuels has increased in the electric utility sector, while the use of the more expensive oil and natural gas fuels has declined. Electricity generation is projected to grow 3.3 percent per year between 1983 and 1995. Coal-fired generation is projected to account for 55 percent of total electricity generation by 1995, maintaining its 1983 share. Utility coal consumption, in tons, is projected to rise by about 46 percent from 1983 to 1995 as 83 gigawatts of coal-fired capacity comes on line. Utility coal consumption is projected to increase from 13.2 quadrillion Btu to 19.2 quadrillion Btu from 1983 to 1995 because projected coal prices increase more slowly than prices of other fossil fuels burned by electric utilities and virtually all new fossil fuel-fired boilers will burn coal. Electric utility fuel use is discussed in Chapter 6.

With the majority of forecasted coal consumption taking place in electric generating plants that are now in operation or under construction, U.S. coal use is projected to be relatively insensitive to alternative world oil prices through 1995. Coal consumption is lower in the high oil price case than in the low oil price scenario because of lower electricity sales in a more slowly growing economy, but its relative share is slightly higher than in the mid and low world oil price cases.

Coal export markets are expected to again increase, after the recovery from the worldwide recession as the world demand for coal increases. The United States, which has been predominantly a metallurgical-coal exporter, is forecast to increase steam coal exports from the current level as more oil-importing countries shift from oil-based economies toward coal-based economies. While metallurgical-coal exports are expected to increase slightly over the projection period, 50 percent of the coal exported by the United States is projected to be steam coal by 1995 (58 million short tons). The demand for U.S. coal could fluctuate depending upon the world economic recovery, world coal and oil prices, government policies, foreign exchange rates, and producer and consumer behavior.

Coal Supply

The rate of growth in coal demand is likely to be the major factor limiting U.S. coal production through the 1990's. The mining and transportation infrastructure to produce and deliver what is required is in place, or can be put in place to meet the demand. Coal production is projected to increase from 900 million short tons in 1985 to 1,191 million short tons in 1995.

During the 1970's, coal production in the States west of the Mississippi River grew significantly. Western coal production grew at an average annual rate of nearly 15 percent while its share of total U.S. coal production increased from 7.3

percent (45 million short tons) in 1970 to 36 percent (282 million short tons) in 1983. Over the forecast period, an even more rapid development of western versus eastern coal resources is projected to continue. By 1995, the projections show that about 39 percent of the U.S. coal production (463 million short tons) will occur in the West (Figure 33). Much of this growth is to supply western demand regions that shift from oil- and gas-fired generation to new coal-fired generation. In particular, Texas lignite consumption is expected to increase by 41 million short tons from 1984 to 1995, primarily because 10 new, minemouth lignite-fired power plants are planned to come on-line. The West is projected to increase its coal consumption by 111 million short tons from 1983 to 1990 and by an additional 58 million tons between 1990 and 1995.

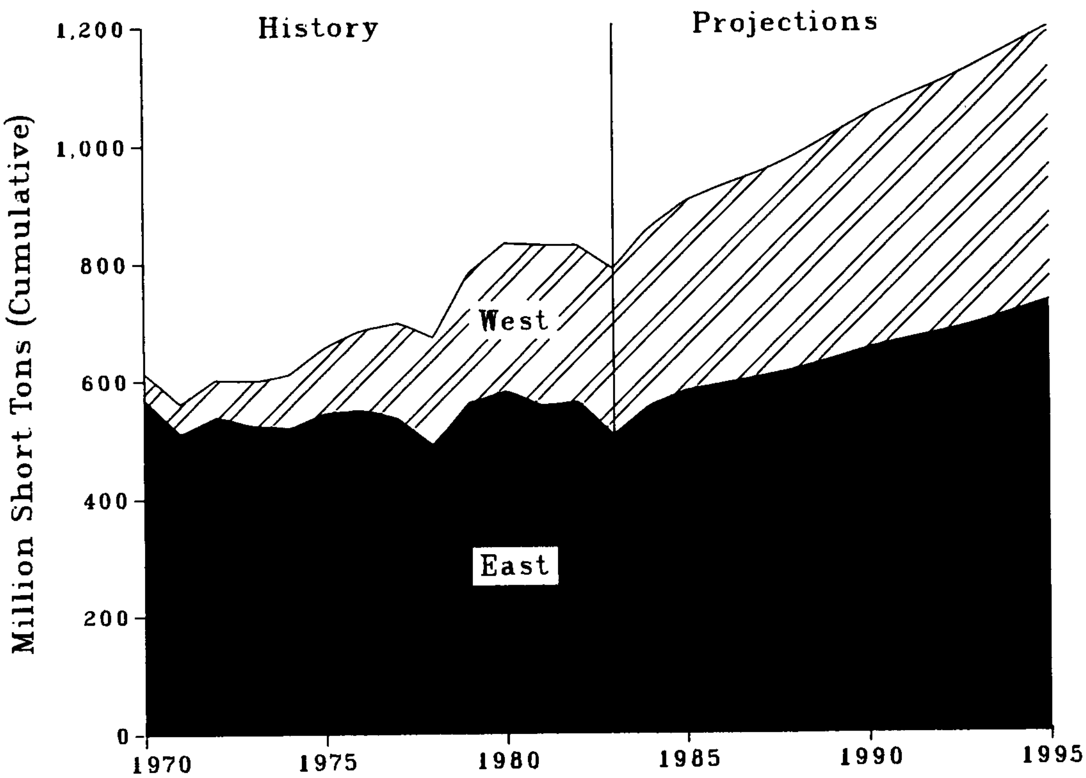
Approximately two-thirds of the U.S. coal resources included in the Demonstrated Reserve Base are minable by underground methods, as reported in Energy Information Administration, Coal Production in 1982, DOE/EIA 0118(82) (Washington, D.C., October 1983). Most of these resources are located in the East. The remaining one-third of domestic coal resources can be mined by surface techniques and three-fourths of these are located in the West. From 1985 to 1995, surface mining is projected to decrease in the East and increase in the West by 11 million short tons and 116 million short tons, respectively. The decrease in the East is due primarily to the depletion of economically minable surface coal reserves.

The quality of coal produced is strongly influenced by the demand and regulatory constraints governing its use, i.e., the Clean Air Act. Lignite produced in Texas and the Dakotas is used primarily for generating electricity in these States, and, additionally, may be used for synthetic fuel production in the Dakotas. Anthracite, produced mainly in eastern Pennsylvania, is primarily used in the residential market and for generation of electric power. Eastern coal reserves contain predominantly bituminous coals with high-Btu and medium-to-high-sulfur content. The relatively small amount of eastern low-sulfur coal reserves is used predominantly for the U.S. metallurgical market and for exports.

Western coal production has not increased as rapidly as had been expected in the 1970's because the proposed Revised New Source Performance Standards of the Clean Air Act require utilities to use sulfur emission controls in new plants regardless of the sulfur content of the coal burned. Therefore, western coal (mainly low-Btu, low-sulfur coal) is not as attractive to users as it would have been without these standards which link sulfur emissions contents to the sulfur content of the coal burned. Therefore, the requirement placed on coal users could change in the future, thereby affecting future production.

Under the changing world oil price scenarios, one might expect consumption of an alternative fuel such as coal to be affected in two opposing directions. One, consumption may increase with higher oil prices as coal substitutes for oil. Alternatively, coal consumption may decline with high oil prices because more expensive oil creates generally higher prices for total energy and thus depresses the overall economy and energy consumption. The second effect dominates in these projections, although the magnitudes of the changes are small. With high oil prices, coal consumption declines by 17 million tons in 1995, and with low oil prices consumption increases by 14 million tons.

Figure 33. Coal Production by Region, Midprice Scenario, 1970 to 1995



Sources: Historical data: U.S. Department of the Interior, Bureau of Mines, Minerals Yearbooks, (Washington, D.C.) selected years; Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984); and Short-Term Energy Outlook, DOE/EIA-0121(84/1Q).

Coal Exports

The use of steam coal has been expanding worldwide as nations have sought to become less dependent on oil imports from OPEC. The United States, Australia, South Africa, and Poland are currently the primary coal exporters. Each country has abundant coal reserves and is expected to continue as a major participant in the world coal market through 1995. Australia is to be the major competitor of the United States in the Far East, and South Africa the main competitor in the Western European coal market. While the delivered cost of U.S. coal is higher than that of the other suppliers, the United States has provided essential surge export capacity in the past and has fewer potential constraints on export expansion.

As foreign countries have shifted consumption towards coal, U.S. exports of coal reached a peak in 1981 but dropped slightly in 1982 and more sharply in 1983, due to a worldwide economic recession, stable or declining oil world prices, and the return of Poland to the world coal markets. Exports of coal are expected to rise slightly by 1985 and then to begin increasing at a faster rate, reaching a level of 105 million short tons by 1990 and 116 million short tons in 1995 (Table 17). Most of the exports are expected to be shipped from East Coast ports.

Table 17. U.S. Coal Exports, 1973 to 1995
(Million Short Tons)

	Actual			Projected		
Coal Type	1973	1978	1983	1985	1990	1995
Steam Coal	11	11	28	35	49	58
Metallurgical Coal	43	30	50	47	55	58
Total Export	54	41	78	83	105	116

Note: Totals may not add due to rounding.
Source: 1973-1978--Energy Information Administration, Weekly Coal Production, DOE/EIA-0218 (83/05) (Washington, D.C., 1983), Table 27, p. 33; 1983--Energy Information Administration, Weekly Coal Production, DOE/EIA-0218(84/08), (Washington, D.C., 1984) Table 9, p. 9; 1985-1995--Energy Information Administration's International Coal Trade Model projections.

Coal Exports

Over the past decade, the use of steam coal has expanded worldwide as many nations have sought to become less dependent on oil imports from politically unstable regions. U.S. coal exports have also increased significantly since 1979, following the crude oil price increases of the Organization of Petroleum Exporting Countries (OPEC). Between 1979 and 1981, U.S. coal exports rose from 66 million short tons to 113 million short tons, reflecting increased demand as well as inability of two other major exporters, Australia and Poland, to share in the expanding market because of labor problems.

In 1982, however, U.S. coal exports dropped slightly, to 106 million short tons, reflecting the effects of a worldwide economic recession, stable or declining world oil prices, and return of Poland to the world coal markets. These trends continued in 1983, and U.S. coal exports continued to decline as world demand for coal dropped. A detailed discussion of the history of U.S. coal trade over the past decade can be found in the EIA report, Historical Overview of U.S. Coal Exports, 1973-1982 (DOE/EIA-0413).

Because of the continuing effects of the stable or declining oil prices and experience during the recent world economic recession, the worldwide steam coal import demands in this report are significantly lower than the 1982 AEO estimates (Table 18). In general, steam coal import projections are derived from detailed analyses provided by each importing country and take into account GNP growth, electricity demand growth, and conversion to and scheduled new construction of coal-consuming capacity. In almost all estimates, GNP growth and electricity demand growth have been scaled down in the past 2 years. Conversion to and new construction of coal-fired capacity has also slowed down because of the prospect of more stable oil prices in the next few years.

Two EIA analysis reports evaluated developments affecting U.S. coal exports. The first report, Railroad Deregulation: Impact on Coal (DOE/EIA-0399), examined the impact of Interstate Commerce Commission actions to deregulate coal hauling rates on U.S. coal exports and world coal trade. The other report, Port Deepening and User Fees: Impact on U.S. Coal Exports (DOE/EIA-0400), was prepared to evaluate alternative methods for financing the maintenance and deepening of U.S. port channels.

Table 18. Comparison of 1983 and 1982 Annual Energy Outlook[1] 1990 Coal Export Projections (Million Short Tons)

	1983 AEO			1982 AEO[2]		
Exporters	Steam	Metal-lurgical	Total	Steam	Metal-lurgical	Total
United States	49	55	105	82	61	144
Non-United States	167	118	285	256	125	381
Total	216	173	390	338	186	524
U.S. Share, percent	23	32	27	24	33	27

[1] A supply region, West Germany, and a demand region, Eastern Europe, have been included and a supply region, India, has been removed from the Annual Energy Outlook, 1983 projections. Numbers from the 1982 Annual Energy Outlook have been adjusted accordingly for comparability.
[2] Excludes anthracite coal and lignite trade.
Note: Totals may not equal sum of components due to independent rounding. Percentages are calculated from unrounded data.

Uranium

U.S. uranium reserves, recoverable at $50 per pound of uranium oxide (yellowcake), are estimated to be 570,000 tons as of the end of 1983. Production of yellowcake totalled approximately 10,600 tons in 1983, a decrease of about 2,900 tons from the 1982 figure. Even so, the United States remained the world's largest producer and processor of uranium intended for use in commercial nuclear power plants.

U.S. utility uranium inventories totalled 68,600 tons at the end of 1982. This total includes uranium in both the natural and enriched forms. This inventory is equivalent to about 4 years of future domestic reactor requirements. Uranium oxide is converted into uranium hexafluoride that is subsequently processed at the Department of Energy's uranium enrichment facilities and then fabricated into fuel assemblies for use in nuclear reactors. About 2,200 tons of foreign-origin uranium were delivered for enrichment at DOE enrichment plants in 1983, representing 17 percent of the 13,100 tons delivered.

U.S. Uranium Mining and Milling Industry

The decrease in production levels and concomitant increase in imports renewed Congressional concern about the Federal Government's responsibility in the area of monitoring the viability of the U.S. uranium mining and milling industry. This resulted in the enactment of Section 23 of the Nuclear Regulatory Commission Authorization Act, Public Law No. 97-415, on January 4, 1983. This Act requires the President to submit a one time report presenting the results of a comprehensive review of the current and projected status of the domestic uranium mining and milling industry. The Act also requires the Secretary of Energy to establish criteria for use in monitoring and annually assessing the viability of the industry. The Energy Information Administration is carrying out data and analysis activities in support of this program. After public hearings, the EIA formulated the final set of criteria. These were issued by the Secretary, then published in the Federal Register on October 6, 1983.

The EIA will collect data for use in measuring the current and projected status of the domestic uranium mining and milling industry for a future 10-year period. The criteria for assessing the status of the industry are based on the idea that a viable industry must be capable of meeting domestic requirements under a range of eventualities--for example, the disruption of deliveries of contracted imported supplies. A determination of the industry's viability will be made by the Secretary of Energy on the basis of data provided by the EIA.

The data provided by EIA will also be used as the basis for determining whether or not further actions will be required under Section 23 by the Secretary of Energy. If the Secretary determines that uranium is being imported in quantities that are sufficient to cause serious injury (or the threat of serious injury) to the industry, the U.S. International Trade Commission must be asked to initiate an investigation under Section 201 of the Trade Act of 1974. In addition, if the Secretary determines that the then-existing contracts constitute more than 37.5 percent of domestic uranium requirements for a 2-year period or feels that the level of import contracts may threaten to impair the national security, he must ask the Secretary of Commerce to carry out an investigation of the national security impact of uranium imports under Section 232 of the Trade Expansion Act of 1962.

6. Electric Utilities

Over the past 30 years, electricity has played an ever-increasing role in energy production and consumption in the United States. In 1953, 16 percent of the primary energy consumption in the United States was used to produce electricity. By 1983, electric utilities used 35 percent of the primary energy consumed.

Electric power now supplies more than 13 percent of the energy consumed by end-users compared with 9.6 percent in 1973. Despite a nearly 60-percent increase in the real price of electricity, the proportion of end-use energy consumption served by electricity has risen by 38 percent since 1973, while the total use of other forms of energy has fallen. The rise in electricity use has occurred, in part, because its price has fallen relative to the prices of other energy forms. In 1982, the ratio of the average residential price of electricity to the average price of the same quantity of natural gas (in dollars per million Btu delivered) was 3.5 down from 4.5 in 1973. The demand for electricity has also been enhanced by its efficiency and adaptability.

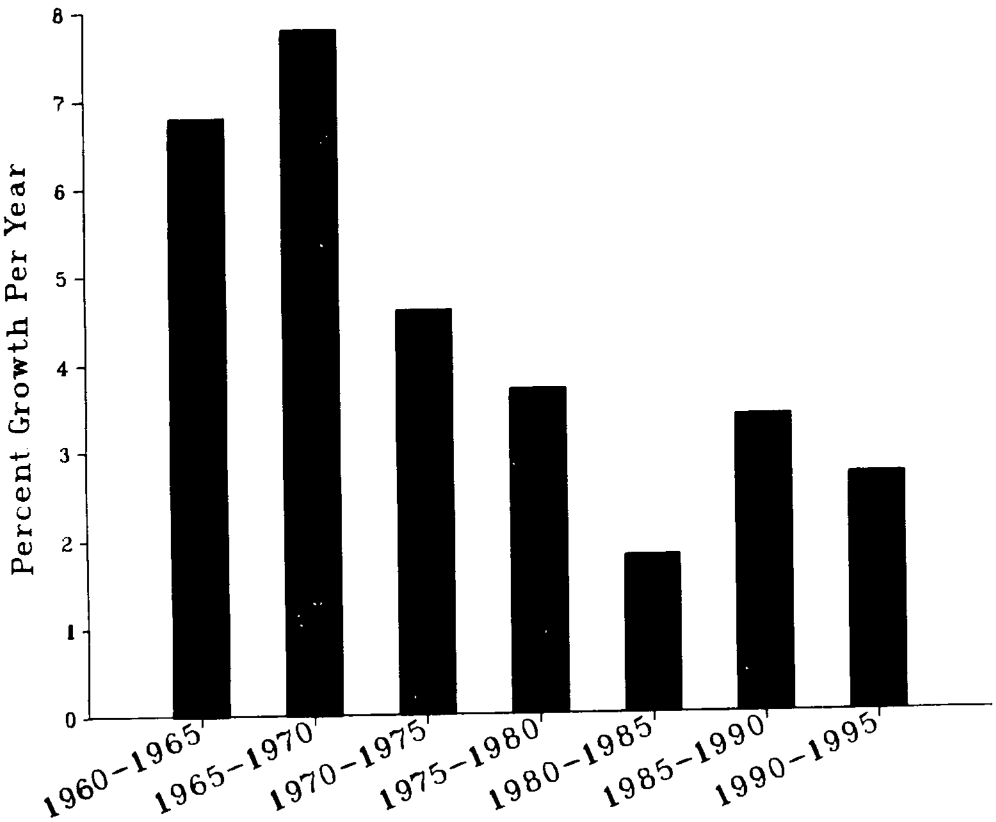
This chapter describes the outlook for the production and consumption of electricity generated and sold by utilities through the remainder of the 1980's and the first half of the 1990's. The patterns of electricity demand for the projection period are discussed together with the generation equipment required to support this demand. The fuel requirements and sources of production of electricity will be projected and compared with current fuel usage patterns. Finally, the projected changes in the price of electricity and aggregate utility financial conditions over the forecast horizon are outlined. The components of prices are discussed so that the causes of changes in overall prices and financial structure can be analyzed.

Demand for Electricity

Sales of electricity have expanded almost continuously for many years. Since the end of World War II, only the recessions of 1974 and 1982 have caused an absolute year to year drop in the sales of electricity. However, the rate at which demand expanded has varied with the changes in economic activity, prices, and the introduction of new technologies designed to be powered by electricity. The rate of electricity demand growth was, on the average, quite high in the 1950's and 1960's. The annual average rate of increase during the 1950's was 9.0 percent, declining to 7.3 percent during the 1960's, and 4.2 percent over the decade of the 1970's. Figure 34 summarizes some past and projected rates of growth in electricity demand. Since 1970, rising energy prices, conservation, and reduced growth in economic activity have induced relatively slower rates of electricity demand growth.

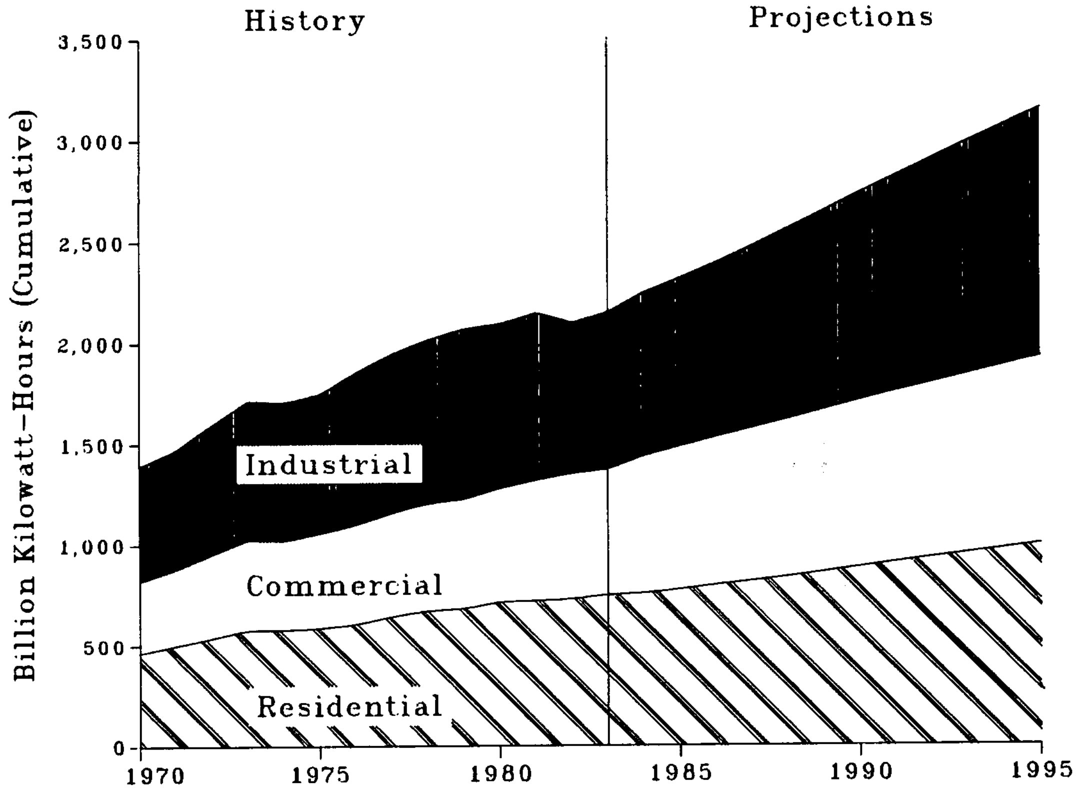
Patterns of electricity use by sector help explain how this slower growth has come about. (See Figure 35.) In the residential sector, electricity use has continued to grow, but at a relatively slow pace. Conservation has cut the rate of electricity use growth through the penetration of energy-efficient appliances, additional investments in energy-efficient structural improvements, and rising prices. In the future, despite these developments, electricity use is projected to grow as the economy and population expand and new energy-using services are introduced. However, the total quantity of electricity demanded is projected to grow only slightly more rapidly than the economy.

Figure 34. Average Annual Rates of Growth in Electric Utility Sales, 1960 to 1995



Source: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984).

Figure 35. Electricity Consumption by End Use, Midprice Scenario, 1970 to 1995



Note: Transportation use of electricity does not exceed 3 billion kilowatt-hours per year and is not shown in the figure.

Sources: Historical data: Energy Information Administration, State Energy Data Report, 1960 through 1981, DOE/EIA-0214(81) (Washington, D.C., 1983); Monthly Energy Review, DOE/EIA-0035(83/12[4]).

In the commercial sector, electricity use has grown very rapidly as the service sector of the economy expanded. Technical innovations, building styles, and increasing wealth have also contributed to the increase in electricity use in this sector. Growth in the commercial sector, in conjunction with new technologies and increased automation of existing business service operations, has led to growing intensity of use of electricity per square foot of commercial floor space. The average annual sectoral growth rate in electric consumption by the commercial sector was 3.4 percent over the period 1973 to 1983, and is projected to continue to rise to an average of 4.1 percent from 1983 to 1990. After 1990, the average rate of growth is projected to decline to 2.4 percent per year as the rate of commercial expansion slows with the general economy. Electricity consumption in this sector is also projected to become more efficient so that the intensity of electricity consumption in the commercial sector is projected to rise slowly.

Industrial electricity consumption is also projected to rise because the overall efficiency in the use of electric processes compensates for the relatively high cost per Btu of electricity when compared with alternative processes that use competing fuels. From 1973 to 1983, industrial electricity sales rose at an annual average rate of 1.2 percent, and by 1983, utility electricity was supplying more than 13.5 percent of the energy input to the industrial sector. The quantity of electricity used per unit of industrial output rose by approximately 0.2 percent per year during this same period. In the projections, this trend is expected to continue, increasing the electricity share of industrial fuel consumption to 18 percent by 1995 and slightly raising the electricity intensity of industrial output.

This increase is projected to occur despite the conservation impacts of new technologies, which are expected to enhance greatly the efficiency with which electricity can be used in many traditional heavy industrial electric applications, such as induction heating, electric-arc furnaces, and heavy-duty pumps and fans. The rise in intensity of use is projected to occur because many of these processes, such as the substitution of electric furnaces for open hearth methods in steel-making, are expected to increase the total quantity of electricity used in industry.

Total utility electricity sales are projected to rise at an average annual rate of 3.9 percent with the continuation of the economic recovery from 1983 to 1985. From 1985 to 1990, electricity sales are projected to grow at an average rate of 3.4 percent per year, slightly more rapidly than real GNP. For the final 5-year interval of the projections, electricity sales are expected to increase at an average annual rate of 2.8 percent, so that, over the entire forecast period, electricity sales grow at an annual rate of 3.2 percent.

Over the range of forecast cases, higher oil prices reduce electricity sales proportionately less than total energy consumption, in part, because electricity prices are less responsive to changes in oil markets than are other energy prices. The majority of the difference in electricity sales between oil price cases is accounted for by variation in sales to the industrial sector because industrial energy consumption is more sensitive to growth in the overall economy than are the residential and commercial sectors.

Supply of Electricity

The rate of future electricity demand growth has important implications for electric utilities because long construction lead-times, high capital intensity, and long-lived physical plants characterize the industry. Currently, generating capacity utilization rates in the electric utility industry are low, as a result of the recession and unexpectedly slow demand growth. Extremely long lead times in the construction of baseload electric generating facilities--averaging about 8 years for coal-fired facilities and more than 13 years for nuclear facilities--have left the industry with the results of construction plans for new facilities made during years of much higher demand growth. Although the industry has scaled back capacity expansion plans, trying to accommodate lower rates of growth in demand, the earlier building plans have created capacity in excess of what is generally regarded as needed for reliable service. The increase in costs per kilowatt-hour resulting from this general overcapacity situation have been exacerbated by the rapid rise in the cost of building and financing new power plants during the 1970's. The combined result of the slowdown in demand growth, rising new-capacity costs, and escalating fuel costs has been to suppress new plans for additional capacity (Table 19).

Table 19. Available Electric Utility Generating Capacity by Energy Source (Gigawatts at End of Year)

Fuel	1985	1990	1995
Coal-fired	306	336	365
Nuclear-powered	85	111	119
Oil- and Gas-fired	223	224	238
Steam	165	165	165
Turbines	51	52	66
Combined Cycle	7	7	7
Other			
Hydroelectric/Other[a]	71	73	73
Hydroelectric, Pumped-Storage	15	19	19
Total	700	762	813

Note: Components and totals rounded independently. A gigawatt is 1,000 megawatts (1 billion watts).

[a]Includes all conventional hydroelectric facilities and other generating equipment not accounted for elsewhere, including geothermal, wind, wood, and waste.

Source: Table A12, Appendix A.

Nuclear Plant Cancellations

By the end of 1983, 106 nuclear generating units, totalling about 116,000 megawatts of capacity had been cancelled. These cancellations represent 47 percent of the total commercial nuclear capacity previously ordered. The Energy Information Administration study, Nuclear Plant Cancellations: Causes, Costs, and Consequences (DOE/EIA-0392), estimates that the abandonment costs associated with the cancellation of the 100 nuclear units which occurred through 1982 was about $10 billion. About 30 percent of these costs were estimated to be borne by utility investors, 30 percent by utility ratepayers, and 40 percent by income tax payers.

The study identified lower projected load growth, financial constraints faced by most investor-owned utilities, and reversals in the economic advantage of nuclear power plants over coal-fired alternatives as the most significant reasons underlying these cancellations.

The study also concludes that the completion of a number of the nuclear plants already cancelled, or subject to potential cancellation, could result in the displacement of electricity generated by oil and natural gas, thus providing net economic benefits to ratepayers and the Nation as a whole.

In addition to the cancellations which occurred through the end of 1983, four nuclear units, totalling about 4,000 megawatts, were cancelled or in immediate jeopardy of cancellation as of the end of January 1984. This capacity is not assumed to operate during the time period of this projection. Furthermore, construction on 10 reactors, originally scheduled for completion by 1995, has been either stalled or indefinitely deferred. If these reactors are not completed, projected nuclear capacity in 1995 could fall by about 11,000 megawatts, or 9 percent of the projected total.

The effects of these changes in the industry are projected to reduce both the average size and total number of new generating plants built over the projection period. New plants are estimated to add 154 gigawatts (million kilowatts) of capacity to the generating stock by 1995. Because of the lengthy time required to bring new capacity into service, much of the projected new capacity is already under construction. All nuclear capacity additions projected to become operational by 1995 are currently in the construction "pipeline." The majority of new coal-fired facilities that will be in use by 1995 are also already being built. However, additional coal-fired facilities accounting for 11 gigawatts (15 percent of projected new coal-fired generating capacity shown in Table A13) are assumed to be added to the stock of new utility capacity by the end of 1995.

The generating capacity projections shown in Table 19 are calculated as though there were no net retirements of generating capacity. In regions where aging capacity must be used in order to meet demands, it is assumed to be either refurbished or replaced in order to maintain generation levels. By 1995, the total net stock of generating capacity is projected to consist of 365 gigawatts of coal-fired capacity, 119 gigawatts of nuclear steam, 238 gigawatts of oil- and gas-fired capacity, and 92 gigawatts of hydroelectric and other facilities. The change in generating capacity over the projection period, a total of 154 gigawatts, includes 11 gigawatts of coal-fired capacity for which construction is assumed to begin during the 1980's and an estimate of 13 gigawatts of oil- and gas-fired turbine capacity which is projected to be ordered and put in service within the forecast period. Figure 36 shows the composition of generating capacity in 1980 and projected for 1995.

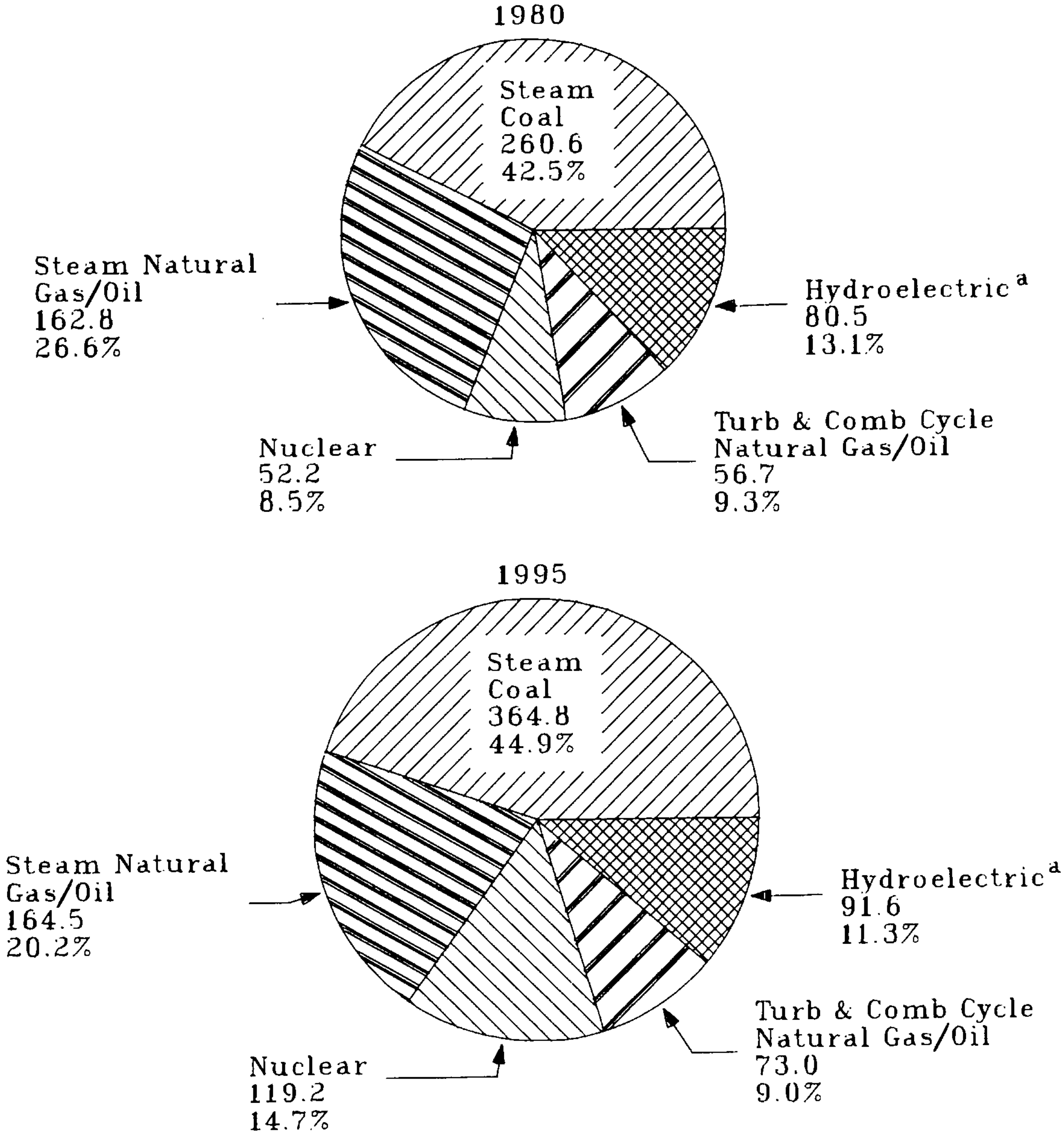
At the end of 1983, coal-fired steam generating capacity constituted 288 gigawatts or 44 percent of U.S. generating capacity. Coal-fired capacity additions are projected to account for 80 percent, or 76 gigawatts, of all the capacity additions over the 1984-95 period. The majority of these new plants are already being planned or under construction. The typical new coal-fired plant entering service in 1995 is projected to cost about $900 per kilowatt (in 1983 dollars) of capacity before financing charges are added. However, the cost of new facilities can vary depending not only on the accompanying financial costs but also on the size and location of the facility and type of coal the facility is designed to use.

There are 18 new coal units totalling 10.9 gigawatts of capacity that are designated to burn lignite as a fuel. Almost 80 percent of the new lignite-fired capacity is projected to be in operation before the end of 1990. The cost of transporting lignite is high because it is difficult to handle and has a low energy content per ton. Therefore, plants burning this low-Btu fuel must be built close to the mine to be economical. The projected new lignite-fired facilities are located in the States of Arkansas, Louisiana, North Dakota, and Texas where there are large deposits of this fuel. The remaining new coal-fired capacity burns higher Btu bituminous or subbituminous coal. This coal is more economic to transport than lignite so that delivered fuel costs are low enough to allow these plants to be located closer to other markets for electricity.

While the majority of new generating capacity is projected to be coal-fired, 238 gigawatts of oil- and gas-fired capacity are projected to be in the generating stock in 1995. This capacity is projected to include 66 gigawatts of oil- and gas-fired turbines used to meet peaking demand. Peaking capacity is characterized by quick start-up capability and there are only limited opportunities to substitute other energy sources for oil and natural gas for peaking use. The remaining 172 gigawatts of existing oil- or gas-fired plants are combined cycle and steam units that are expected to be used primarily for baseload and intermediate demands that cannot be met with plants having lower fuel costs.

The projected growth in net generating capacity is substantially smaller than the overall growth in demand; therefore, the utilization rates for electric generation facilities are expected to be higher and reserve margins to be lower than those experienced in recent years. Reserve margins, the percent of capacity not used at the time of peak demand, measure utilities' abilities to meet growth in peak demand. In general, the industry considers a reserve margin of 20 percent desirable

Figure 36. Electric Utility Generating Capacity Shares (Million Kilowatts and Percent)



[a]Includes all other.

Source: Historical data: Energy Information Administration, Inventory of Power Plants in the United States, 1982 Annual, DOE/EIA-0095(82) Washington, D.C., 1983.

in order to allow for sudden increases in demand or system failure, and to assure service within desired reliability limits during peak demand periods. In some regions of the Nation, where growth in demand is high, reserve margins may decrease to the point where the industry feels that service may become less reliable.

Electric Utility Fuel Use

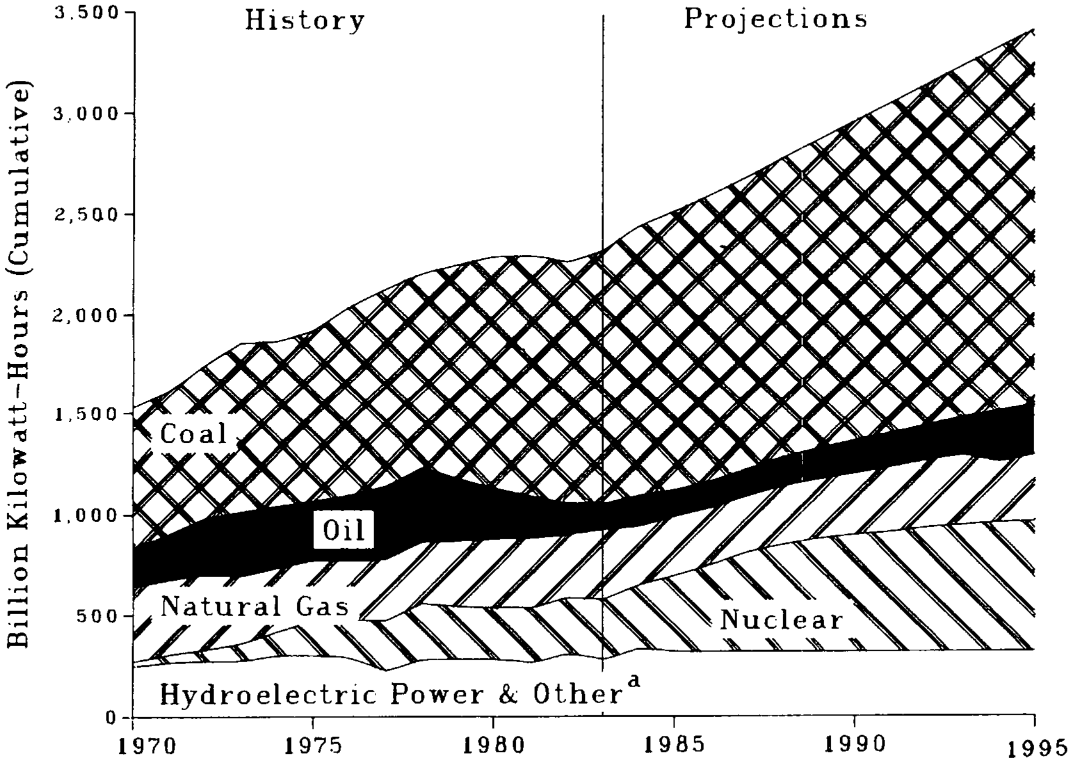
The energy sources consumed as fuels by the electric utility industry are determined by the types of generating equipment available to the industry, the demand for electricity from final consumers, and the relative prices of fuels to the industry. Major changes in the fuels used to generate electricity have occurred since the 1973 oil embargo; the use of coal and nuclear fuels has increased while the use of more expensive oil and natural gas has declined. In 1982, oil and natural gas supplied only 21 percent of the energy used to generate electric power. There was a strong downward trend in oil and gas use even before the sharp decline due to the 1982 recession. The trend toward reduced reliance on oil and natural gas would have continued even without the recession, as new generating capacity became available to displace older facilities.

In 1973, coal-fired generation supplied 46 percent of the electricity generated in the United States, while nuclear-powered generation provided less than 5 percent. Oil and natural gas were used to generate 35 percent and hydroelectric power supplied the remainder. During the decade since that time, coal-fired and nuclear-powered generation have risen to 55 and 13 percent, respectively, as the prices of natural gas and, especially, oil have risen much more rapidly than have coal prices.

Coal-fired and nuclear-powered generation are expected to expand as a share of output in the projection period. By 1990, the combined output from these plants is projected to be 74 percent; coal-fired electricity is expected to constitute 54 percent of total generation and nuclear-powered generation is projected to rise to 20 percent. Oil- and natural gas-fired electricity is expected to supply only 16 percent of total output. As a proportion of total domestic generation, the share of natural gas and oil combined reaches its lowest level in 1987. Historical and projected quantities of generation by fuel are shown in Figure 37.

As electricity demand continues to rise over the 1990 to 1995 period, the quantity of oil and gas used is projected to rise again because economic growth requires additional electricity that cannot be generated by other, less expensive fuels. However, the oil- and gas-fired shares in total electric energy use remain below 18 percent. By 1995, coal-powered generation is projected to be remain 55 percent of the total output; nuclear power is projected to supply another 19 percent of all generation. Hydroelectric generation is projected to remain approximately constant in absolute terms but, because there are fewer opportunities to expand this source by large increments, the share of generation that it can supply is projected to decline to less than 10 percent by 1995.

Figure 37. Sources of Electrical Supply, Midprice Scenario, 1970 to 1995



[a]Other includes geothermal, wood, waste, and net imports of electricity.

Sources: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83); Monthly Energy Review, DOE/EIA-0035(83)/12[4]) (Washington, D.C., 1984).

The addition of new generating facilities and improvements in the utilization rates of existing plants are expected to bring about growth in the coal-fired and nuclear generating shares. Since coal, nuclear-powered, and water-powered generation provide the least expensive energy sources for generating electricity, they are the sources of power used most extensively. The quantities of oil and natural gas projected to be consumed by utilities in 1995 are less than the amounts used for this purpose in 1979. Few nontraditional central station power sources are projected to be available, except for about 2 gigawatts of geothermally powered facilities located in the West. Production of electricity in facilities not owned or operated by utilities, including cogeneration and small power production facilities, is excluded from the projections. In general, the types of generating plants and fuels used to produce electricity are projected to be similar to those currently used.

The primary effect of alternative oil price scenarios on electric utility fuel use is to lower the quantities of higher priced energy sources consumed as increasing oil prices dampen economic activity and the demand for electricity. As a consequence of lower electricity output requirements, by 1995 the share of total electric utility inputs supplied by nuclear, hydroelectric, and other sources rises from 29 percent in the low oil price case to 29 percent in the high oil price case. Under these same circumstances, coal's share rises from 52 percent to 54 percent despite a decline in the absolute amount of coal that is burned. The combined share of oil and natural gas also falls from 19 percent to 16 percent of energy input. Furthermore, because the relative prices of oil products and natural gas change as oil price paths shift, the share of electric utility energy inputs supplied by residual fuel oil changes from 11 percent in the low price case to 4 percent in the high price case while the natural gas share partially compensates by rising from 7 percent to 12 percent between the same cases.

Fuel Switching Between Oil and Gas

Since oil and natural gas are currently the most expensive utility fuels, electric utilities try to limit their consumption by using more coal, nuclear, and hydropower. Consequently, changes in the relative prices of oil and gas have little effect on their combined use by utilities. However, the relative prices of oil and natural gas play a significant role in determining their respective generation shares. Currently, most utilities which are able to use natural gas have chosen to do so because oil is more expensive.

However, the ability of utilities to switch fuels may be limited in the short run by other considerations. Most oil and natural gas burned by utilities is purchased under contracts; therefore, changing fuel consumption patterns may require waiting until existing obligations expire or incurring additional expenses to buy out or abrogate these contracts. Some contractual arrangements may also insulate utility fuel prices from short-run changes in market prices. In either case, the use of contracts tends to slow down adjustments to changes in market conditions. Furthermore, utilities may prefer to hedge fuel dependency by maintaining links with both suppliers. In the event of an interuption in the supply of one fuel such as those caused by the 1973 oil embargo or by natural gas deliveribility constraints during periods of cold weather peak heating demand, alternatives are immediately available.

In any case, electric utilities can respond to changes in prices or the availability of oil or natural gas in two ways. First, they can revise the dispatch order of their plants so that units burning the less expensive fuel are utilized more intensively. Second, many plants have multifuel boilers capable of burning either oil or natural gas. Consequently, these dual-fired units can respond to changes in fuel prices and supplies by switching input fuels. This dual-fired capability is a strong incentive for suppliers to maintain price parity between competing fuels.

In 1982, about 164 gigawatts, 26 percent of the total available U.S. generating capacity, consisted of steam plants that burned oil or natural gas. Of this capacity, about 100 gigawatts were dual-fired units capable of using either fuel. Although some dual-fired steam units are only capable of short-term emergency alternative fuel use, many of these plants can sustain long-term continuous firing with either fuel. The remaining 64 gigawatts represented generating units that can burn only one fuel, either oil or natural gas.

Much of the potential for fuel-switching is located in two regions of the United States. The Southwest has about 61 gigawatts of oil- and natural gas-fired steam generating capacity. Of this capacity, approximately 48 gigawatts are dual-fired units capable of burning either oil or gas. The West has approximately 24 gigawatts of dual-fired capacity that can burn either oil or gas. These two regions have almost three-fourths of the dual-fired steam capacity and are currently the largest utility gas consumers, accounting for almost 80 percent of the total electric utility gas consumption in 1982.

Legislation has affected the use of natural gas by electric utilities. The Powerplant and Industrial Fuel Use Act of 1978 restricted the use of natural gas in existing power plants. However, these restrictions on natural gas use were eliminated as part of the Omnibus Budget Reconciliation Act (OBRA) of 1981. In addition, OBRA includes the Electric Utility Conservation Plans that require utilities using gas in the 12 months prior to passage of the Act and planning to use natural gas in the future to file a conservation plan setting forth steps to reduce the amount of electricity generated over a 5-year period. The plan must be approved by the Department of Energy. The reduction in electric output must be at least equal to 10 percent of the electric generation attributed to natural gas during the base year.

Nuclear Generation

At the end of 1983, there were 80 operable nuclear units totalling more than 64 gigawatts (GW) of capacity.* During 1983, 7 nuclear units became operable and

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* The term "operable" is defined to include all nuclear units that have completed low power testing and have been granted full power authorization by the Nuclear Regulatory Commission, plus the DOE-owned Hanford N reactor that sells power commercially through the Washington Public Power Supply System. Also, Three Mile Island 1 is included in this total. It is not, however, included in the 1983 capacity totals shown in the appendix tables. Instead, in order to better represent nuclear generation, it is shown as a capacity addition in 1984, the year of its expected re-start.

began generating electricity. The net electricity generation produced by all operating nuclear capacity was 292 billion kilowatt-hours in 1983 or 13 percent of the total electric generation, the same percentage as in 1982.

As has been the case since 1978, no new units were ordered during 1983; 6 were cancelled. By the end of 1983, the total number of cancellations since 1972 was 106, thereby reducing the number of units planned or under construction to 55 (Table 20).

Table 20. Status of U.S. Nuclear Power Plants, End of 1983

Status	Number of Reactors	Net Design Capacity (mW)
Operable		
In Commercial Operation	76	60,200
In Power Ascension	4	4,200
Total	80	64,400
In Low Power Testing	3	3,400
In Construction Pipeline		
Under Construction		
Greater than 50 percent complete	37	40,400
30 to 50 percent complete	4	4,600
Less than 30 percent complete	2	2,400
Indefinitely Deferred	10	11,700
Reactors on Order	2	2,200
Total	55	61,300
Total	138	129,100

Source: Capacity data from the Nuclear Regulatory Commission, Licensed Operating Reactors, NUREG 0020 (February and December 1983) and Nuclear Power Plants Construction Status Report, NUREG 0030 (October 1982). Status data from Monthly Energy Review, DOE/EIA-0035(83/12[4]) (December 1983), pp. 81-83; and Energy Information Administration, Form EIA-254.

Note: Includes Three Mile Island 1, but not Three Mile Island 2 or Dresden 1.

The projections for nuclear power generation are governed by anticipated schedules for plants in the construction pipeline and expected retirements. Given the average length of lead times necessary to construct nuclear units, it is not anticipated that a new order for a reactor would result in an operating unit before the end of the projection period. As shown in Table 19, nuclear capacity is expected to increase to 111 GW in 1990 and to 119 GW in 1995. The relatively rapid growth in the earlier period results from the projected completion of the large number of plants that are currently more than 50-percent complete. The construction schedules of these plants are considered to be less flexible than for later plants because of their large sunk costs. The nuclear generation projected for 1990 is 581 billion kilowatt-hours or about 20 percent of total U.S. electric utility generation. The much slower growth in operating nuclear capacity in the post 1990 period results from the numerous plant cancellations, and delays of plants in the earlier stages of construction, especially second units. Nuclear generation in 1995 is projected to be 643 billion kilowatt-hours or 19 percent of total U.S. electric utility generation.

The average nuclear plant capacity factor is projected to remain approximately at the 1982 level of 55 percent through 1988 and then to increase to 62 percent by 1995. This pattern of average nuclear utilization results from a combination of factors. First, new nuclear units are assumed to operate at an average rate of only 42 percent during the first 2 years of operation and then increase to a 62 percent utilization rate. Second, ongoing safety modifications related to the Three Mile Island (TMI) accident, along with relatively weak demand for electricity, have resulted in outages and down times at many existing nuclear plants. As these modifications are completed and electricity demand grows as projected, these plants are expected to increase their average rate of utilization from 1982 levels to a target of 62 percent in 1990.

The South Atlantic and Midwest regions are currently the areas with the largest amounts of nuclear generation; this is projected to continue to 1995. The nuclear share of total regional generation was highest in New England and New York/New Jersey in 1983, and this also is expected to be the case in 1995. Of the total nuclear capacity projected to be completed in the forecast period, nearly 70 percent is located in four regions: the South Atlantic, the Midwest, the Southwest, and the West.

Nuclear Plant Construction Cost Estimates and Leadtimes Continue to Increase

The electric power industry has experienced increases in the cost estimates for construction of nuclear power plants. According to the EIA study, 1983 Survey of Nuclear Power Plant Construction Costs (DOE/EIA-0439), final construction cost estimates (in nominal dollars) for nuclear power plants were at least double the preconstruction estimates in 36 of 47 operating plants surveyed. In 13 of the 47 plants, the final estimate was more than four times the initial estimate. The difficulty of making accurate cost projections at the initiation of construction can be attributed to variability in inflation rates during the construction period; changes in interest rates; changes in technical designs necessitated by revisions insafety and environmental standards; and increases in construction lead times, which cause increases in the total financial charges.

According to the EIA study, nuclear power plants that began commercial operation in the early 1970's experienced construction periods of 4 to 6 years. By the mid-1970's, the average construction time for completed plants had increased to 7 to 8 years. Since 1977, the average time from start of construction to commercial operation had increased to over 9 years, and by the early 1980's the average time had increased to almost 12 years.

For nuclear generating units that are currently under construction, the average of the electric utilities' estimates of the time from application for a construction permit to commercial operation is approximately 14 years, with the time between the application to start construction and the actual start of construction being 2 years. The average time to obtain a construction permit and the average time from the application for an operating license until the unit sustains a controlled nuclear chain reaction (i.e., first criticality) have also been increasing.

Environmental Concerns

Along with the changing mix of fuels used to generate electricity, certain environmental issues have become increasingly prominent. Most notable currently is pollution from the combustion of coal. The air and water pollution associated with the production of electricity has received a great deal of attention since the initial effort to control pollution was enacted by Congress as the 1963 Clean Air Act. Environmental legislation has led to major changes in the structure and operation of the electric generation equipment. The existing laws are represented in these projections by the New Source Performance Standards and Revised New Source Performance Standards incorporated in the planned costs of new generating facilities. The selection of new generation equipment and the methods of operating all plants are assumed to comply with existing legislation. However, air pollution issues, most notably those surrounding sulfur dioxide and nitrogen oxides emissions, remain questions of national policy. It is assumed in the projections that existing standards will be met.

Acid rain has been the subject of several legislative proposals that usually have focused on the electric utility industry as a principal source of sulfur dioxide (SO_2) emissions. Acid rain refers to the wet and dry deposition of acids--chiefly sulfuric and nitric acids--from the atmosphere to the earth's surface. Acid rain occurs after SO_2 and nitrogen oxides (NO_x) emissions combine in the atmosphere with other materials in a chemical reaction. One study of proposed legislation is discussed in the box below; however, since no legislation has been enacted, no additional provisions to reduce acid rain are included in these forecasts.

Proposed Clean Air Act Amendments of 1982

Senate bill S. 3041, the "Clean Air Act Amendments of 1982," submitted during the 97th Congress, addressed the problem of acid deposition (acid rain) in the eastern United States. This legislation proposed reducing the SO_2 emissions and limiting the NO_x emissions in a region that includes 31 States and the District of Columbia: the 26 States east of the Mississippi River and 5 States contiguous to it on the west. Senate bill S. 3041 proposed that, by 1995, this region reduce annual SO_2 emissions to 8 million tons less than actual emissions in 1980, a reduction of approximately 50 percent of electric utility emissions in 1980. Increases in SO_2 emissions after January 1, 1981, were to be offset by reductions from other sources. Emissions of NO_x were not to increase over 1980 levels.

Senate bill S. 3041 did not pass the 97th Congress. However, similar bills calling for annual SO_2 emission reductions or other means of reducing acid rain have been proposed. Some would have allowed the substitution of reductions in NO_x emissions for required reductions of SO_2 emissions. Others proposed charging a fee for each kilowatt-hour of electric energy generated or imported in the contiguous 48 States, except for electric energy generated by nuclear generating facilities, to cover capital costs necessary to reduce emissions.

Electric utilities can reduce SO_2 emissions from existing power plants by retiring or reducing the use of units burning high-sulfur coal, by changing the type of coal the boiler burns to one with lower sulfur content, and/or by retrofitting units with flue gas desulfurization (FGD) systems. Many factors influence the ways electric utilities choose to reduce their SO_2 emissions. Principal factors are the expected rate of growth in electricity demand (which affects plant utilization rates and retirements) and coal transportation costs (which affects the economics of switching to lower sulfur coal).

A recent EIA study of S. 3041 projects a 5.2- to 6.4-percent increase in the real price of electricity in 1995 due to higher coal costs and additional capital expenditures for utilities to comply with this legislation. This price hike corresponds to a $7.1 billion to $11.6 billion increase (1983 dollars) in the 1995 revenue requirements for electric utilities. The additional cumulative capital expenditures by utilities from 1983 through 1995 under S. 3042 are projected to range from $10.5 to $21.5 billion (1983 dollars). The $10.5 billion capital expenditure is comprised of $3.5 billion for FGD, $2.5 billion for boiler modifications, and $4.5 billion for new transmission lines and new capacity.

Under S. 3041, switching to lower sulfur coal is projected to be the preferred method for electric utilities to reduce SO_2 emissions, resulting in large shifts in regional coal production. In the Midwest, coal production is projected to drop below its 1980 level, and in Northern Appalachia and the Central West, coal production is projected to grow at a slower rate than recently expected. Central Appalachia and the Western Northern Great Plains are projected to increase coal production because of the adaptations made in order to comply with the legislation. Five States (Ohio, Missouri, Indiana, Pennsylvania, and Illinois), which account for 50 percent of the projected reduction in SO_2 emissions, are projected to have both higher electric utility capital expenditures and lower State coal production with this legislation.

These findings, and others, are contained in the EIA study, Impacts of the Proposed Clean Air Act Amendments of 1982 on the Coal and Electric Utility Industries (DOE/EIA-0407).

Alternative Forecasts for Electric Utilities

Tables 21 and 22 compare 1982 and 1983 Annual Energy Outlook (AEO) projections of net generation by fuel type for 1990 with similar projections published by Data Resources, Inc. (DRI), the North American Electric Reliability Council (NERC), and the Electric Power Research Institute (EPRI).

The 1983 AEO projection of 1990 total net generation is higher than the DRI and NERC projections, but significantly lower than the EPRI forecast. The 1983 AEO projection implies a 3.5-percent annual increase in net generation over the 8-year projection period, compared to implied growth rates of 2.9 percent, 3.3 percent, and 5.7 percent for DRI, NERC, and EPRI, respectively. The 1983 AEO projection is somewhat lower than the 1982 AEO projection, reflecting a downward revision in projected total demand for electricity.

The EIA projects that coal-fired and nuclear generation together will account for nearly three-fourths of total generation in 1990, up from a combined share of approximately two-thirds of the total in 1982. This projection is higher than the DRI forecast for the combined share because DRI projects that coal's relative share will decline somewhat over the period. The NERC projection of the combined share reflects a significantly greater projected contribution from nuclear units than that projected by the EIA and DRI. The NERC projects that the share of generation supplied by nuclear units will nearly double by 1990, while EIA and DRI expect a more modest increase in the nuclear share of net generation.

Table 21. Comparison of Growth in Electricity Generation and Energy Shares, 1990

Generation	1982 Actual	1983 AEO	1982 AEO	DRI	NERC	EPRI
			(annual percent rate)			
Projected rates of growth 1982-1990	NA	3.5	4.0	2.9	3.3	5.7
			(percent share)			
Coal/Nuclear Share	65.8	73.7	71.3	69.9	77.7	NA
Oil Gas/Share	20.2	15.5	18.6	17.6	11.9	NA
Coal Share	53.2	54.0	52.0	49.9	53.3	NA
Oil Share	6.6	5.3	11.6	8.0	3.4	NA
Gas Share	13.6	10.3	7.0	9.6	8.5	NA
Fossil Share	73.4	69.6	70.6	67.5	65.2	NA
Nuclear Share	12.6	19.7	19.3	20.0	24.4	NA
Hydroelectric Share	13.8	10.8	10.1	11.7	[a]9.3	NA
Other Share	0.2	(b)	(b)	0.9	1.4	NA

[a]The variations in NERC and EIA projections of hydroelectric generation reflect different assumptions about water conditions during the projection period. EIA assumes average water conditions while NERC assumes adverse water conditions (low rainfall).

[b]Included in hydroelectric.

NA=Not available.

Sources: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035683/12[3]), (Washington, D.C., February 1984); Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(82), April 1983; Data Resources, Inc., Energy Review, Winter 1983-1984; North American Electric Reliability Council, Electric Power Supply and Demand, July 1983; and Electric Power Research Institute, Overview and Strategy 1982-1986, November 1981.

Table 22. Comparison of Electricity Generation by Type of Fuel for 1990 (Billion Kilowatt-Hours)

Fuel Type	1982 Actual	Forecast for 1990: 1983 AEO	1982 AEO	DRI	NERC
Fossil Fuels					
Coal	1,192	1,594	1,603	1,402	1,547
Oil	147	155	358	224	100
Gas	305	303	216	270	246
Subtotal	1,644	2,052	2,177	1,896	1,893
Nuclear Power	283	581	595	563	707
Hydro	[a]309	[a]318	[a]310	[a]328	271
Other	5	(b)	(b)	[c]25	32
Geothermal Power ...	(d)	(b)	(b)	NA	18
P.S. Load	(e)	(e)	(e)	(e)	-20

[a]Includes pondage generation plus energy loss for pumped storage generation.

[b]Included in Hydroelectricity.

[c]Described as generation from "Solar and exotic" sources.

[d]Included in "Other."

[e]Hydroelectric generation figure is net, and therefore reflects pumped storage (P.S.) load.

NERC = North American Electric Reliability Council.

NA= Not available.

Sources: Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/12[3]), February 1984. Energy Information Administration, Annual Energy Outlook, DOE/EIA-0383(82), April 1983; Data Resources, Inc., Energy Review, Winter 1983-1984; North American Electric Reliability Council, Electric Power Supply and Demand, July 1983; and Electric Power Research Institute, Overview and Strategy 1982-1986, November 1981.

Cost of Electricity

The average real price of electricity began to increase in the 1970's after more than 30 years of decline. In general, the real price increases are attributed to real increases in construction costs per kilowatt of capacity, increases in fuel costs, and diminishing economies of scale, and technological improvement in operating efficiency of large central plants. During the late 1970's and early 1980's, unanticipated high interest rates combined with longer leadtimes, especially in the case of nuclear plants, to increase further the construction costs of new plants, leading to additional increases in the real price of electricity to consumers.

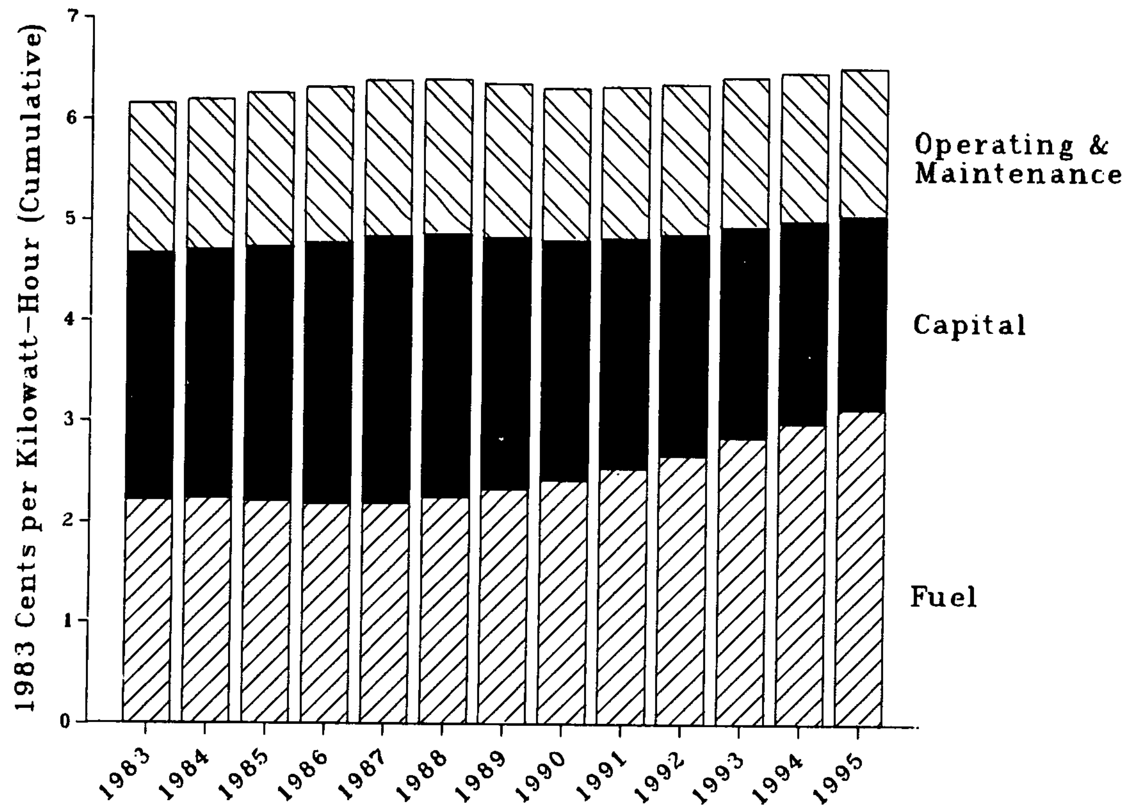
The average real price of electricity for the Nation is projected to increase at a lower rate for the rest of the decade and into the 1990's. The national average price per kilowatt-hour (kWh) of electricity is projected to increase in real terms at an annual average rate of 0.5 percent from 1983 to 1995.

Electricity prices are determined by the utilities' costs of producing and delivering electric power to consumers. The regulation of utility prices is designed to ensure that revenues collected by a utility on services sold are equal to the cost of providing the service. The cost of electricity is generally divided into two major components, capital-related costs and operating costs. The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders. The operating cost component represents the cost for the utility to operate and maintain the physical plant required for serving the consumer. The major elements of this component are fuel costs and other operating and maintenance (O&M) costs.

Nationally, capital-related costs are projected to account for nearly 40 percent of the average cost of electricity in 1983, whereas fuel and O&M costs represent 36 and 24 percent, respectively. Throughout the forecast period, the capital cost component is projected to account for nearly 30 to 42 percent of the electricity price whereas the fuel component is projected to account for from 34 to 48 percent. Figure 38 and Table 23 provide a detailed view of these data.

The projected real electricity price changes for the period 1983 to 1987 are caused by the increasing contribution of the capital cost component and the decreasing contribution of the fuel cost component. During the period 1989 to 1995, the opposite prevails: the fuel-cost component increases and the capital cost component declines. The capital cost-component is projected to rise from nearly 40 percent of the average real cost of electricity in 1983 to a peak of nearly 42 percent in 1987 and gradually decline to about 30 percent in 1995. The magnitude and direction of the capital-cost component and its contribution to the average real price of electricity is a function of three factors. First, a significant portion of all plants presently under construction are expected to be completed during the next 4 years. Second, many of these plants have experienced significant unanticipated cost escalation and have accrued substantial financing costs due to high interest rates during prolonged periods of construction. These two factors result in higher total capital costs to the consumers.

Figure 38. Average Electricity Prices and Cost Components, Midprice Scenario, 1983 to 1995



Source: Appendix A Table A14.

Table 23. Cost Components of Real Average Electricity Prices For Total Industry (1983 Dollars)

	1983	1984	1985	1986	1987	1988	1989	1990	1995
Electricity Price (cents/kWh)	6.17	6.21	6.27	6.33	6.39	6.40	6.36	6.32	6.52
Capital Cost (percent)	39.7	39.7	40.2	41.0	41.5	40.7	39.2	37.5	29.5
Fuel Cost (percent)	36.1	36.1	35.4	34.5	34.2	35.2	36.7	38.4	48.0
Operating & Maintenance (percent)	24.2	24.2	24.4	24.5	24.3	24.1	24.1	24.1	22.5

Percentages calculated independent of rounding.
Source: Table 14, Appendix A.

The third factor, electricity demand growth, decreases the impact of the higher plant costs by spreading the total capital cost (fixed charges) increases over a larger number of kilowatt-hours of electricity sales. This factor thus moderates the contribution of the per unit capital-cost to the real increase in electricity price. As a majority of the plants now under construction are completed, the capital-cost component of real electricity price can be expected to decline.

The fuel-cost component is projected to decline from 36 percent of the average real cost of electricity in 1983 to a low of 34 percent in 1987 and then rise to 48 percent in 1995. The decreasing fuel-cost component which prevails until 1987 is the result of a significant amount of new plant capacity coming into service that utilizes lower cost fuels (uranimum and coal) and stable or declining real oil and gas prices. Beyond 1987, the fuel-cost component of electricity price is expected to rise as existing oil and gas steam plants, which use more expensive fuels, are required to contribute more in order to meet demand growth while at the same time the prices of these fuels also begin to rise.

Although the price of electricity on a national and regional basis is projected to remain relatively stable over the forecast period, several individual utilities may experience severe changes in their prices ("rate shock") as large new plants are completed and enter rate bases. These shocks are a result of regulatory treatment of capital expenditures when they enter the rate bases for revenue determination and the magnitude of the new investments. The plants entering the rate base have experienced significant escalation in cost due to long construction lead times, high inflation rates, and high financing costs. The utilities that are likely to experience rate shock are those that complete plants for which capital costs represent a significant portion of the net value of the assets currently included in their rate bases.

The pattern exhibited for each region's electricity cost components differ from those of the national aggregate depending on each region's unique fuel and capital characteristics. For example, in New England, Region 1, where oil still accounts for a large portion of total generation (44 percent in 1983), and new construction is low with only 4 GW introduced by 1995, the capital component of electricity cost varies from 34 percent in 1984 to 43 percent in 1988 and the fuel component varies from 42 percent in 1984 to 36 percent in 1988. The capital component for this region is lower than the national average of nearly 40 percent in 1984 and 41 percent in 1988, whereas the fuel component is significantly higher than the national average of 36 percent in 1984 and nearly equal to the national average of 35 percent in 1988.

Financing Utility Construction

The electric utility industry is very capital intensive. In 1982, the electric utility industry construction expenditure requirements of $31.3 billion accounted for approximately 9.0 percent of the total nonresidential fixed business investments for the domestic economy.

For the period 1983 to 1990, the electric utility industry is projected to require $235 billion current dollars for capital expenditures on physical plant additions. As shown in Table 24, in real terms (1983 dollars), the industry will need $198 billion, or an average of about $25 billion per year, for installing new capacity. Of this total, about $119 billion is required for all new generating capacity ($56 billion is projected for nuclear plants and $59 billion for coal plants.) The total capital requirements for the period of $235 billion (in nominal terms) represent about 70 percent of the total net value of existing assets of investor and publicly owned utilities in 1983. (These assets are estimated to be valued at approximately $357 billion.)

Additions to the electric utility industry's rate base during the forecast period (1983-90) are projected to approach $290 billion (nominal). The projected increases to the rate base include all expenditures on plants which come into operation by 1990. These expenditures include both outlays incurred prior to 1983 and those projected to occur during the 1983 to 1990 period. The additions are nearly equal to the estimated net value ($357 billion) of all existing assets for the total industry in 1983. Of this total, nuclear plants are projected to account for approximately $127 billion worth of new plants entering into the rate base whereas coal-fired plants account for $62 billion. Approximately 78 percent or $100 billion of the nuclear assets are expected to enter into the industry's rate base during the 1984 to 1987 period, accounting for 39,854 megawatts (MW) or 81 percent of the total 49,469 MW scheduled to come on line during the entire period from 1983 to 1990. The projected peak for nuclear plants entering the rate base is expected to occur in 1987 when approximately 10,010 MW and $29 billion are forecast to be absorbed by the industry.

Table 24. Projected Annual Capital Expenditures for Electric Utilities, Midprice Scenario, Selected Years (Million 1983 Dollars)

Year	Nuclear	Coal	Total
1983	14,109	7,700	31,577
1984	11,817	7,497	29,479
1985	9,502	6,972	26,854
1986	7,304	7,052	23,950
1987	4,844	7,284	21,982
1988	3,498	7,593	21,351
1989	2,882	7,705	21,383
1990	2,226	7,607	21,447
Total	56,182	59,410	198,023

Source: Energy Analysis and Forecasting Division, Office of Energy Markets and End Use and Electric Power Division, Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration.

Investor-owned utilities, which in 1982 accounted for 76 percent of the industry's generation and 77 percent of total generating capacity, are currently experiencing a period of modest financial recovery. This recovery was brought about by decreases in the rate of inflation, improvements in allowed returns on equity, reduced regulatory lags, more stable fuel prices, and moderation in the need for capital expenditures for new generating plants. This recovery is projected to continue throughout the forecast period. The continuing improvement will be aided significantly by the completion of a majority of the construction programs currently under way.

The ability of the investor-owned utility industry to raise new capital during the rest of the 1980's is expected to be aided by increases in utilities' internal cash flow. As the investor-owned utilities wind down their existing construction programs, they will reduce the external financing burden they have borne for many years. The projected improvements in internal cash generation will significantly reduce the industry's need for external capital, and will improve its overall financial health. As shown in Table 25, the investor owned utility industry's internal cash generation to construction expenditure ratio is projected to increase from 49 percent in 1983 to 89 percent in 1990. During the same period, the earnings available to meet the industry's fixed interest obligations are projected to improve from 2.3 times interest expenses in 1983 to 2.8 times in 1990.

Table 25. Projected Electric Utility Financial Ratios for Investor-Owned Utilities, Midprice Scenario

	1983	1984	1985	1986	1987	1988	1989	1990
Financial Ratio								
Interest Coverage[a]	2.3	2.3	2.4	2.5	2.7	2.8	2.8	2.8
percent of Internal Financing[b]	49.2	66.0	63.5	80.8	91.0	96.5	93.6	89.3
AFUDC as percent Earnings[c]	66.4	64.2	55.0	42.7	28.3	23.0	22.2	21.7
Return on Equity (percent)[d]..	15.3	15.3	14.8	15.3	15.2	15.9	15.9	15.8
CWIP as a Percent of Net Plant[e]	34.6	29.9	23.2	17.3	11.4	10.8	10.9	9.7

[a]Pre-tax earnings less AFUDC (does not reflect interest expenses for nonelectric operations).
[b]Internal cash as a percent of construction expenditures.
[c]Allowance for funds used during construction (noncash item) as a percent of common stock earnings.
[d]Earned return on equity.
[e]Construction work in progress as a percent of net electric plant.
Source: Energy Analysis and Forecasting Division, Office of Energy Markets and End Use and Electric Power Division, Office of Coal, Nuclear, Electric, and Alternate Fuels, Energy Information Administration.

The quality of earnings, as indicated by the ratio of the allowance for funds used during construction (noncash earnings that are associated with future benefits of current construction activity) to total earnings available to common equity, are projected to improve from 66 percent in 1983 to 22 in 1990. In addition, the ratio of construction work in progress to net electric utility plant is projected to decline from about 35 percent in 1983 to 9.7 percent in 1990.

It should be noted that the above indicators are based on aggregate projections and are presented for estimating the trend for the aggregate. However, many individual utilities are and will continue experiencing significant financial problems during the 1980's, even though the projected aggregate industry indicators imply improving financial conditions for the industry in general.

In the projections, the improvement of financial health for the industry is expected to result from the completion of plants under construction, the growth in the demand for electricity, and the reduced reliance on expensive fuels. However, this improvement hinges on future demand growth being realized and on regulatory actions. Future growth in the demand for electricity also depends on electricity prices remaining competitive with alternative energy sources.

7. Energy in the Economy

The Economy's Response to Energy Prices

The primary mechanism by which events in the world energy market affect the economy is through prices. Energy price changes are followed by changes in the general price level which, in turn adversely affects aggregate demand and total employment. This section examines these interrelationships in more detail and considers the potential range of monetary and fiscal policies available to counteract adverse effects. While this discussion focuses on increases in energy prices, an analogous set of economic mechanisms apply to falling energy prices.

Inflation

An increase in the price of energy has the effect of triggering product price increases. As manufacturers in this country experience increasing energy prices at the production level, it is inevitable that much of the increased energy costs will be passed on to consumers. Increases in the actual and expected inflation rates experienced by consumers may lead them to demand greater wage increases which, if successful, further pushes up product prices. Inflation increases revenues at Federal, State, and local government levels, but inflation also causes increases in the cost of entitlement programs such as unemployment and retirement benefits. The ultimate effect of this cost-push cycle on the inflation rate is determined in large part by the monetary and fiscal policies that are pursued. Any degree of accommodation to higher energy prices by monetary authorities translates into sustained increases in the levels of both inflation and interest rates (because nominal interest rates reflect expectations regarding inflation). Similar consequences flow from accommodating fiscal policy actions.

The Process of Market Adjustment

When the general price level rises more rapidly than wage rates, consumer purchasing power falls and demand for both energy and nonenergy commodities declines. In an international context, a redistribution of income occurs, transferring income away from U.S. consumers to energy producers. About one-third of this income redistribution is to foreign producers; therefore, a critical factor in determining the overall effect of higher energy prices is the extent and speed with which the money is respent in the U.S. economy. Initially, higher expenditures for imports result in a dollar-for-dollar reduction in GNP.

Energy prices affect aggregate demand. As a result, they also have an effect on the level of employment in the economy. In the short run, as the output of the economy falls, the demand for labor declines. However, as the price of one input (energy) rises, producers may substitute another, cheaper input (labor) in industries where labor can be substituted for energy. In the longer run, capital expenditure decisions initiated as a result of energy price pressures will have an effect on the level and composition of employment.

While the financial drain of an oil price shock is significant and adverse, market adjustments tend to moderate these effects over time. Eventually, U.S. dollars will be returned to the economy as claims by oil-exporters for real goods and services mitigating some of the lost output and employment. However, less of the potential aggregate supply is available for domestic consumption.

The potential aggregate output of the economy depends on the availability and efficiency of capital, labor, energy, and raw materials. An increase in the relative price of energy sets in motion efforts to economize on energy use. Higher energy prices tend to make some capital (plant and equipment) designed for a world of cheaper energy prices obsolete. As this part of the capital stock is retired more quickly, and priority is given to investment in energy-saving capital equipment, other planned investments must be postponed. Thus, the effort to "catch up" with higher energy prices may postpone or reduce productivity growth normally associated with new investment.

Nonetheless, the short-run reduction in economic activity accompanying a sudden energy price increase can be expected to lead to generally lower levels of investment until the economy recovers. This decrease in investment would further slow the rate of productivity growth in the long run, because new capital stock is added more slowly. Ultimately, as the economy adjusts to higher energy prices, some of the economic growth apparently "lost" in the initial reaction to the price increase may be recovered, but it is unlikely that all of the "lost" income will be recovered.

Monetary and Fiscal Policy

It is difficult to identify effects on the economy of energy price increases without specifying the macroeconomic policies in place. Even in the absence of an explicitly identified policy initiative, policies are assumed implicitly. In the short run, increases in monetary reserves or deficit spending can be used to offset the negative effects of rising energy prices on employment and output. However, these policies may lead to unacceptably high levels of inflation. The opposite policy holding the line on inflation at the expense of output and employment may be equally unattractive. The most likely response involves a compromise solution between these two extremes. From a longer run perspective, the more important determinants of the recovery of potential aggregate output are the time-path of investment to replace energy-inefficient capital, and the domestic response in terms of alternative energy supplies. In most cases, lead times for decision in these areas are quite long (5 years or more). Decisions are also heavily dependent on whether or not the increase in the oil price is perceived as permanent.

Economic Activity and Energy Consumption

Economic growth is a key factor in determining changes in the economy's overall requirement for energy inputs. Prior to the first oil price shock, many forecasters had concluded that changes in energy demand were approximately proportionate to changes in economic activity. Few hold such a view today. In fact, the way in which an economy's energy requirements change as the economy grows is an important area of uncertainty. High oil prices and rising natural gas prices have significantly affected demand for these inputs.

The Long-Term Economic Forecast

The general character of the long-term economic forecast behind this year's midprice scenario is one of robust growth in all sectors, coupled with continued, moderate levels of price inflation and gradual reductions in nominal rates of interest.[1] No attempt is made to forecast the ups and downs of future business cycles.

In the midprice case, real GNP is forecast to grow briskly over the 1983-85 period at a 4-percent per year rate, fueled by a 6.3-percent per year growth in manufacturing, leading to a 4.1-percent per year growth in real disposable income.[2] These growth rates fall over the longer time frame of 1983-90 to 3.3 percent (real GNP), 4.5 percent (manufacturing), and 2.9 percent (disposable income). They moderate further still viewed over the 1983-95 period to 2.9 percent, 3.6 percent, and 2.6 percent, respectively. Inflation is moderate throughout, but increasing; 4.8 percent growth in the GNP deflator over the 1983-85 is forecast, 5.6 percent over 1983-90, and 6.0 percent over 1983-95. Interest rates are forecast to stay within a relatively narrow band, with the yield on new high-grade corporate bonds falling from a 1984 peak of 11.7 percent to a 1990 low of 10.4 percent, and then remaining within the 10.1-10.5 percent range thereafter.

In contrast to the recent historical movement of the U.S. economy toward services, manufacturing gross output is assumed in these projections to grow at 4.5 percent per year over the 1983-90 projection period while total gross output of the economy is projected to grow at 4.1 percent. Services--a leading sector in the recent past--is expected to grow at only 3.9-percent per year over this period. As a result of this relatively stronger growth in manufacturing, its share of total gross output rises from 23.8 percent in 1980 to 24.5 percent in 1990. This is slightly above the 1970 share of 24.1 percent. The stronger recovery of manufacturing, as compared to services, is essentially due to the fact that manufacturing was more severely hit in the recent recession than other sectors, whereas services stayed relatively insulated from the sharp swings of activity elsewhere in the economy.

Within the manufacturing sector, the top five energy-consuming industries are assumed to grow at the following annual rates from 1983 through 1990:

Food (SIC 20)	2.2 percent
Paper (SIC 26)	3.2 percent
Chemicals (SIC 28)	4.6 percent
Stone, Clay, and Glass (SIC 32)	3.9 percent
Basic Metals (SIC 33)	4.4 percent

Two sectors, (1) basic metals and (2) stone, clay, and glass, experienced dramatic declines in output during the most recent periods of recession. Basic metals declined by 32 percent from its previous peak year, 1979, to its low point in 1982. Stone, clay, and glass declined 23 percent from its peak in 1978 to its low, also in 1982. Chemicals fell more moderately, by 13 percent from its 1979 peak to a 1982 low point, but 1983-90 growth rates still represent a significant rebound from the recession. Paper and food suffered relatively little from the most recent recession, falling by 2.8 and 0.5 percent, respectively, from 1981 to

1982. In the 1979-80 recession, food output did not fall and paper's gross output fell only 1.1 percent. As a result of having lost less ground, their projected growth rates are lower.

As shares of total gross output in the economy, 3 sectors--(1) paper, (2) chemicals, and (3) stone, clay, and glass--are forecast to be fairly stable over the 1983-90 projection period, at points not much below their pre-1979 shares. The erosion of food's share is more or less continuous throughout the forecast, while basic metals simply never totally recover from the declines of 1977-82. These trends, combined with the projected continuing trend toward electrification--a big factor in steel, particularly--are reflected in EIA's projections.

Economic Growth and Alternate World Oil Price Trajectories

There is considerable interest in how the economy reacts to changes in the world oil price. In order to allow for probable differences in economic growth and other economic variables when oil price projections vary, EIA in its forecasting activities has developed methodologies for altering economic assumptions to reflect alternative energy price scenarios. In connection with the midprice projections for this report, as well as the high and low world oil price alternative cases, a certain degree of feedback from the energy sector to the general economy (and then back to the energy sector), was assumed. Table 26 outlines differences in key economic assumptions that resulted from this feedback. Note that even in the baseline projections, final macroeconomic variable projections varied somewhat from the original economic assumptions as they appear in Chapter 3, due to feedbacks allowed for in the forecasting methodology.

As shown in Table 26, oil price variations such as those between the high, middle, and low trajectories are assumed by EIA to result in significant differences in economic growth and inflation rates. Focusing on 1990 in particular, the swing from high to low price cases, representing a variation in oil price growth--in real terms--of from 6.5 percent to -0.1 percent per year, makes a difference in the inflation rate of approximately 0.5 percentage points per year. The impact on inflation, the oil import bill, and real resources available for economic growth, results in turn in variations of approximately 0.3 percent per year in the growth rates for real GNP and real disposable personal income. Manufacturing, which is more sensitive to energy prices than the economy as a whole, shows a variation in growth between the high and low world oil price cases of 0.6 percent per year.

The effects on industrial demand for energy of a change in energy prices is greater than that implied by variations in total gross output in manufacturing.[3] Manufacturing output is 2.2 percent lower than base line in the high price case, and 1.9 percent higher in the low price case. A survey of the top five energy-consuming industries in manufacturing, however, shows that the output of three industries varies by more as oil prices trajectories change; two industries vary by less (Table 27).

Table 26. Key Economic Indicators in the High, Middle, and Low Oil Price Cases

Economic Indicator	1985			1990			1995		
	High	Middle	Low	High	Middle	Low	High	Middle	Low
World Oil Price									
(constant 1983$/bbl.)	30.53	26.52	22.44	45.64	36.65	29.16	65.88	50.49	36.54
Real GNP									
(constant dollars)									
Growth from 1983	3.7	4.0	4.4	3.2	3.3	3.5	2.8	2.9	3.0
Percent Diff. Base	-0.6		0.6	-1.0		0.9	-1.3		1.2
Inflation									
(GNP deflator)									
Annual from 1983	4.8	4.8	4.4	5.8	5.6	5.3	6.3	6.0	5.8
Annual from 5 years ago ...	5.9	5.9	5.7	6.2	5.9	5.6	7.1	6.7	6.5
Gross Output in Manufacturing									
(constant dollars)									
Growth from 1983	6.1	6.3	6.6	4.1	4.5	4.7	3.2	3.6	3.8
Percent Diff. Base	-0.4		0.5	-2.2		1.9	-3.9		3.4
Real Disposable Personal Income									
(constant dollars)									
Growth from 1983	4.0	4.1	4.2	2.8	2.9	3.1	2.4	2.6	2.7
Percent Diff. Base	-0.2		0.2	-1.0		0.9	-2.0		1.7

Source: Economics and Statistics Division, Office of Energy Markets and End Use, EIA.

Table 27. Differences from Gross Output in Base Case, 1990 (Percent)

Manufacturing Industry	High Price Case	Low Price Case
Food (SIC 20)	-0.6	0.5
Paper (SIC 26)	-2.0	1.8
Chemicals (SIC 28)	-2.5	2.2
Stone, Clay, and Glass (SIC 32)	-3.0	2.6
Basic Metals (SIC 33)	-5.2	4.5
All Manufacturing	-2.2	1.9

Source: Economics and Statistics Division, Office of Energy Market and End Use, EIA.

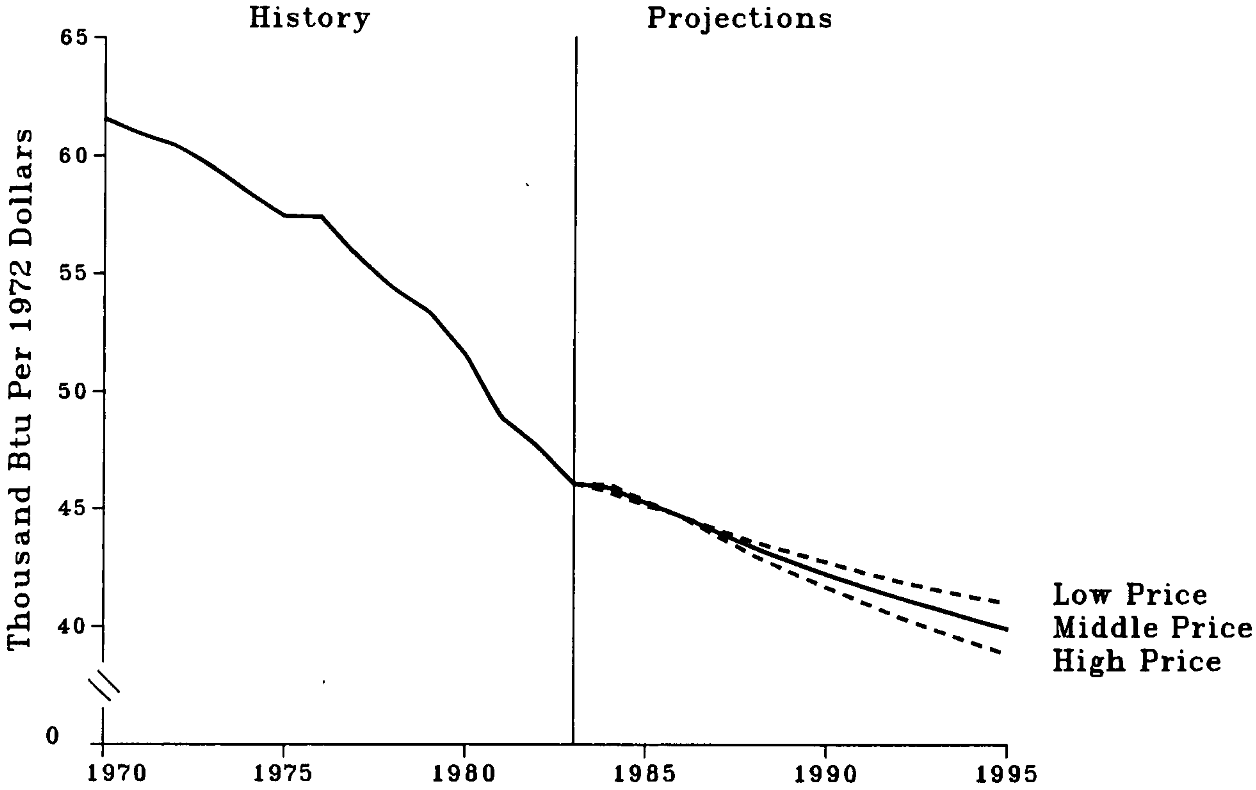
The Energy/GNP Ratio

One measure of the relationship between energy and the economy is the ratio of primary energy consumption to aggregate economic activity. Figure 39 traces this relationship measured in thousand Btu consumed per dollar of GNP (in constant 1972 dollars). Figure 40 displays the relationship between fluctuations in economic activity and aggregate energy consumption. Both GNP and energy consumption are indexed to their respective levels in 1970.

Over the period from 1970 to 1983, the energy/GNP ratio declined at an average rate of 2.2 percent per year. This was accompanied by a steep rise in world oil prices, increasing at an annual average rate of 11.6 percent per year. When the oil price shock of 1973-74 occurred, the ratio responded by falling by 1.8 percent from 1973 to 1974 and 1.7 from 1974 to 1975. This measure of the energy-to-output relationship then began to level off in the 1975-76 period, but then declined further in 1977-78. The largest declines came in response to the price shock of 1979-80 as the aggregate energy/GNP ratio fell by 3.4 percent from 1979 to 1980 and another 5.1 percent from 1980 to 1981.

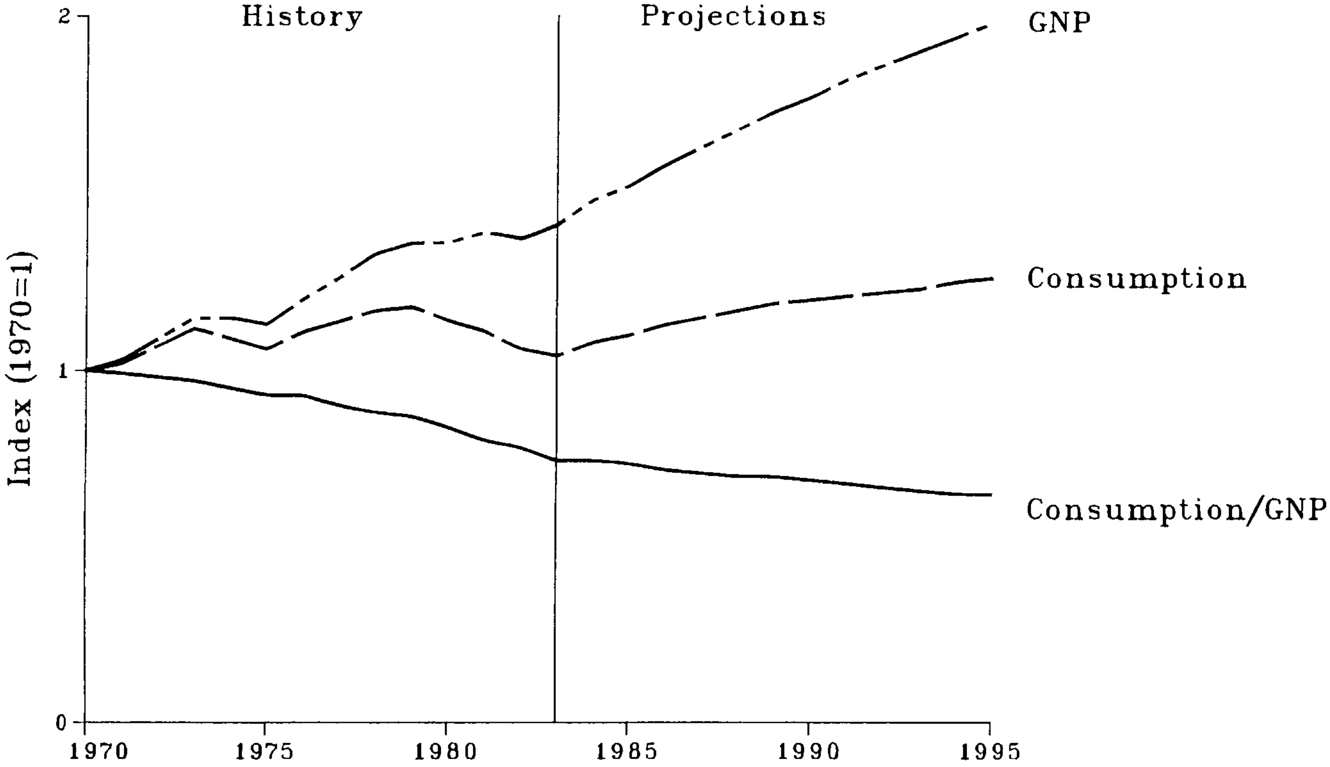
These variations in year-to-year rates of decline in the ratio are partly due to movements in the economy associated with the business cycle as well as year-to-year variations in weather. Fluctuations in GNP are mirrored by similar fluctuations in energy consumption. However, when expressed as the aggregate energy/GNP ratio, this index clearly indicates a trend toward reduced energy use per unit of output. This trend is primarily due to reductions in the energy-output ratio that have been occurring in the great majority of producing sectors, as conservation and new technologies are adopted in responses to higher energy prices. Also contributing to reductions in the aggregate energy-to-output ratio, in some degree, have been shifts in demand away from the more energy-intensive industries, toward those which are less energy-intensive.

Figure 39. Aggregate Energy/GNP Ratio, 1970 to 1995



Source: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984).

Figure 40. Indexes of Economic Activity and Energy Consumption, Midprice Scenario, 1970 to 1995



Source: Historical data: Energy Information Administration, Annual Energy Review, 1983, DOE/EIA-0384(83) (Washington, D.C., 1984).

Movements in the energy/GNP ratio represent a complex set of interactions taking place in all sectors of the economy. The energy projections presented earlier in this report, coupled with projections of economic growth, suggest that the aggregate energy/GNP ratio will continue to decline. However, for the 1983-95 projection period, the energy/GNP ratio is forecast to decline at a rate somewhat less than experienced in the 1970-83 period.

Underlying the projections is the assumption that the price for world oil will follow a path considerably different from what was experienced in the seventies. OPEC's ability to maintain world oil prices has weakened in the last few years, and the base case projection is for this slackness in the market to continue through 1986, as reflected in a declining real price. This near-term slackness is followed by a tighter market in the late 1980's continuing through 1995. While real oil prices rise during the last 8 years of the forecast, the forecast does not follow the volatile path of the previous decade. Thus, the incentives to conserve on oil consumption, and energy consumption in general, will be less than in the 1970-83 period.

Early in the forecast period, 1984 through 1985, the energy/GNP ratio for the high price case is above the ratio for the midprice case. The level of GNP falls in response to the higher price of oil, in part because the oil import bill is immediately affected by the change in the price of oil. However, given the lagged response to the world oil price change, energy consumption changes slowly in the short run. When viewed over the entire range of the forecast period, however, higher world oil prices clearly have the effect of pushing down the energy/GNP ratio as energy consumption declines relative to the midprice case. The converse set of results holds true for the low-price case.

From 1970 through 1983, the world oil price rose at an average annual rate of 11.6 percent. In contrast, the price of world oil is assumed to increase at a rate of just under 5 percent from 1983 through 1995 in the midprice forecast. The forecast rate of decline of the energy/GNP ratio is 1.2 percent compared to 2.2 percent in the 1970-83 period. The high price case assumes that the world oil price will rise 7 percent per year while the energy/GNP ratio declines by 1.4 percent per year. For the low world oil price case (2 percent per year) the ratio declines 1.0 percent per year. In addition, the three standard world oil price paths are relatively smooth, lacking the sharp price hikes experienced in the seventies.

The Economic Effects of an Oil Supply Disruption

The previous discussion considered alternative energy and economic outlooks based on assumptions of a smoothly changing world oil market. Having witnessed the adverse effects on the economy of more rapid changes in oil prices during the 1973-74 and 1978-80 periods, it is valuable to consider how significant changes in energy prices and availability affect the economy. The two oil price shocks are widely considered to be responsible for much of the increased inflationary pressure experienced during the last 10 years. During this period, the annual rate of increase in the Consumer Price Index (CPI) jumped from a relatively low level (only 4.6 percent at a compound annual rate from 1968 to 1972) to a rate of 13.5 percent for the year in 1980. Rapidly rising oil prices also helped to cause recessions in 1974 and 1980.

The effects of oil price shocks on the economy, of course, are ultimately dependent on the monetary and fiscal policy responses which accompany them. Inflation is in the long run a monetary phenomenon and higher energy prices--relative to other prices--should not be seen as a cause of increases in the rate of general price inflation. Rather, only if monetary authorities attempt to mitigate adverse effects on economic activity and employment by increasing the growth of the money supply to accommodate the rise in oil prices, will the overall price level rise permanently above what it otherwise would have been. This is what occurred in the mid and late 1970's following the two oil price shocks, when the CPI accelerated to double-digit rates. However, had policies been pursued to repress all the inflationary pressures of these energy price shocks, higher unemployment than was actually experienced might have been the result.

Whatever the choice of monetary and fiscal policy responses to an oil price shock, the change in relative prices will always have significant effects on the distribution of income, on productivity and investment, and on total real incomes. Significant redistributions of income away from energy consumers to energy producers occur when oil prices rise rapidly. This, together with the reduced productivity of capital and the transfer of real income to foreigners, helps to cause significant economic dislocation--the declines in consumption and investment which led to the 1974 and 1980 recessions. These effects on output and employment are basically unavoidable, although they can be minimized by pursuit of stable monetary and fiscal policies.

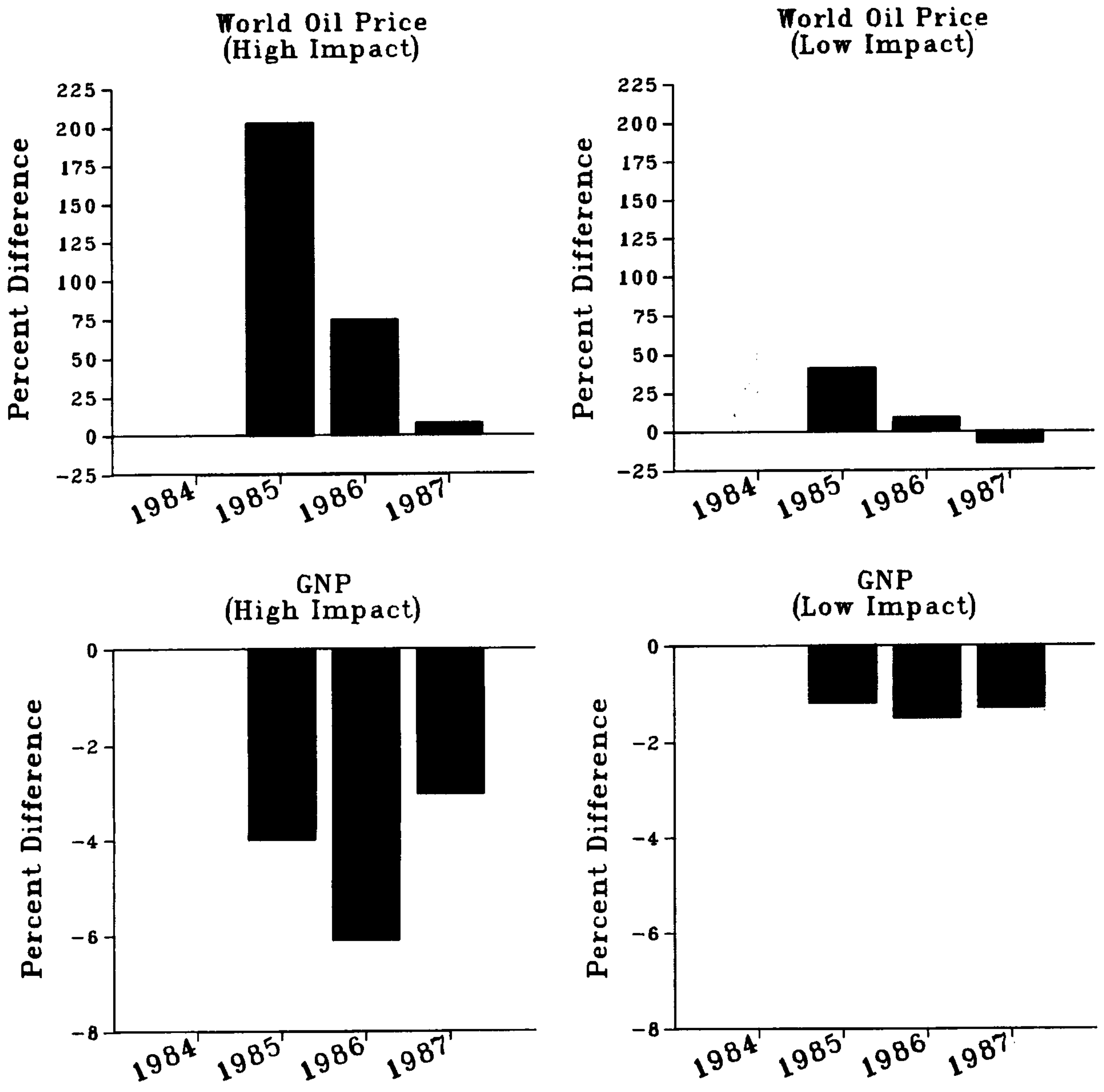
Oil Market Effects

This section continues the discussion begun in Chapter 2 of the uncertainty introduced into energy and economic forecasts by the possibility of an oil supply disruption. Chapter 2 analyzed potential world oil price impacts of a hypothetical disruption; this section analyzes potential impacts on the domestic U.S. economy of such a disruption.

Impacts on the U.S. Economy

The top of Figure 41 illustrates the possible reactions of prices to the assumed loss in oil supplies. The bottom of Figure 41 illustrates the multiyear percentage losses of real GNP that might be expected for the disruption case relative to the midprice case GNP projections. The 2nd year impacts are higher than those of the 1st year due to the lagged effect, especially on investment demand. In the 3rd year real GNP partially recovers, but even by the end of the 3rd year GNP has not recovered to the midprice case level.

Figure 41. Range of Impact of a Hypothetical Supply Interruption on World Oil Prices and Gross National Product



Note: The disruption price range is based on a hypothetical disruption that assumes that world oil availability is cut by 10.5 million barrels per day on January 1, 1985, for a period of 12 months. The impacts are shown as differences from the midprice case.

A detailed examination of the timing of impacts on various economic indicators is presented in Table 28. First-year impacts on consumption expenditures, particularly expenditures on motor vehicles and parts and other durable goods, cause most of the initial decline from midprice case GNP levels. One of the reasons for the heavy 1st-year impact on consumption is the particularly sharp jolt to the inflation and interest rates in 1985 in response to the oil price hike. Much of the 1st-year decline in consumption is caused by a sharp decline in both real income and real wealth, as inflation surges. Given the steady decline of the inflation rate impact over time, the tendency for consumption impacts to diminish similarly over time is more easily understood. A more direct linkage exists between real disposable personal income and consumption. Effects on real income follow the same time-pattern as those on consumption--again partly due to the inflation rate change, and partly to the real impacts on overall economic activity.

Table 28. Range of Macroeconomic Impacts of a Hypothetical Oil Supply Disruption

	1985	1986	1987
Gross National Product (billion constant 1972 dollars)			
Percent Decline from Midprice Case ...	1-4	1-6	1-3
Personal Consumption Expenditures (billion constant 1972 collars)			
Percent Decline from Midprice Case ...	1-5	1-7	1-4
Business Fixed Investment (billion constant 1972 dollars)			
Percent Decline from Midprice Case ...	1-6	3-11	3-7
Personal Consumption Expenditures on Automobiles (billion constant 1972 dollars)			
Percent Decline from Midprice Case ...	13-35	8-30	4-15
Personal Consumption Deflator (Base=1972)			
Annual Rate of Increase	1-6	1-6	0-3
Employment (million jobs)			
Decline from Midprice Case	0.5-1.5	0.5-3	0.5-1.5

Source: Economics and Statistics Division, Office of Energy Markets and End Use, EIA.

The difference between a relatively mild impact on GNP and a severe impact hinges partly on inflationary pressures from a price shock, but also on the response of oil demand to the price of oil (the price elasticity of demand) and the degree of U.S. dependence on oil imports in the midprice case. In the midprice case, the level of imports is 5.45 millions of barrels per day, with the gross fuel oil import bill amounting to $72 billion. In the disruption case, the fuel import bill would range between $50 and $100 billion depending on the world oil price and the degree of import reduction. The uncertainty surrounding oil import payments adds considerably to the uncertainty in predicting real GNP impacts.

Table 28 highlights two of the more important "real costs" of the disruption in the long run. Investment shows a significant decline during the 1st year, although peak impacts do not appear until the 2nd or 3rd year after the disruption. This behavior in investment, showing a lagged response to the overall state of the economy, contrasts with the more immediate impacts on consumption levels. The difference between the base case and the disruption case business capital stock (plant and equipment) grows steadily larger from year to year. This growing differential is reflected in potential output, and represents lost growth that is never completely recovered. A portion of this cost is accounted for by the lost hours of labor input during the 3 years. This loss could be more dramatic than that implied by differences in the unemployment rate because some workers become discouraged and tend to drop out of the labor force.

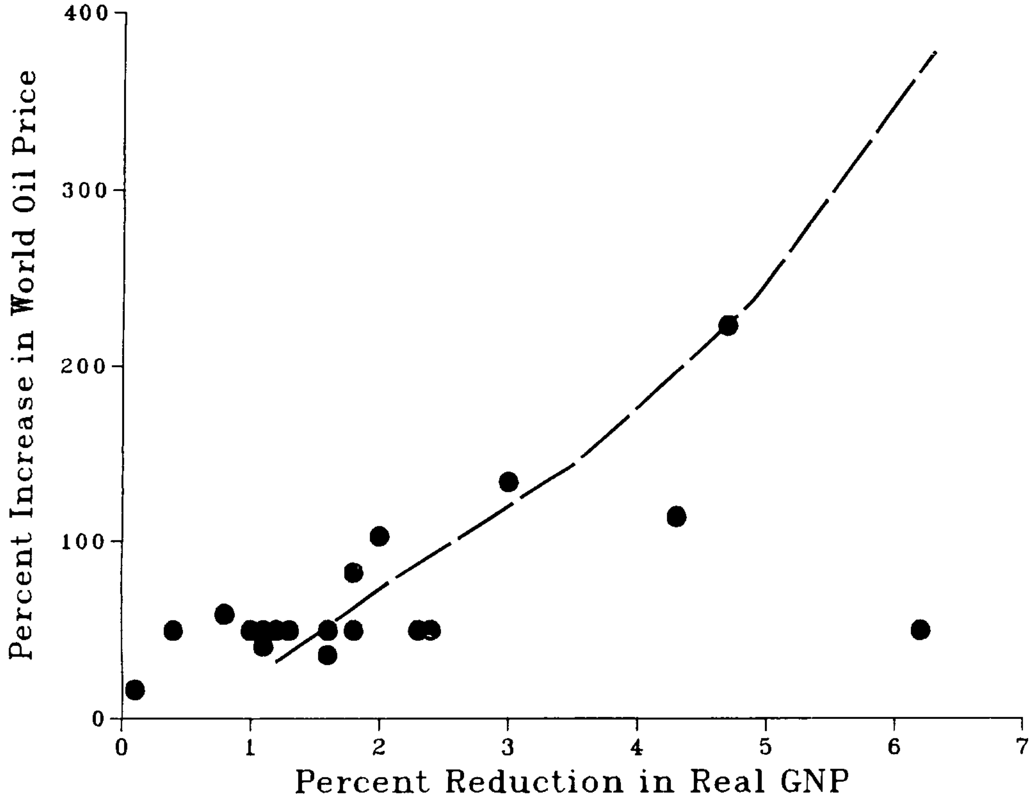
Comparison with Other Studies

The disruption analyzed in the preceding section represents one hypothetical scenario. A recently completed EIA study takes a somewhat broader look at the short-terms impacts on the economy of a disruption in world oil supplies.[4] The emphasis of that study was to compare EIA results to the results of other researchers.

Initially, EIA defined five simplified disruption cases of varying sizes. Based on these cases, a GNP loss function (for the 1st year of the disruption) is calculated showing the percentage loss in real GNP, relative to a base case, associated with various percentage increases in the world oil price. This GNP loss function (shown as the dashed line in Figure 42) then provides a framework for comparing results of other studies surveyed, shown as points superimposed on the GNP loss curve. The points that fall on a horizontal line at a 50-percent increase in the world oil price represent results for a common scenario being analyzed by the Energy Modeling Forum at Stanford University.[5] The remaining points represent results extracted from a review of other research.

It is apparent that the range of estimates of the impact on the economy for the 1st year is large. However, if a few of the outlying points are not considered, the range of results for the vast majority of estimates is considerably smaller. The EIA GNP loss curve falls close to the median of both sets of results. The loss function also exhibits a slight nonlinearity as the world oil price increases, a finding that is consistent with the results of the other researchers. Some of the important reasons for differences among the results hinge on variations in model structure and key assumptions.

Figure 42. World Oil Price/GNP Loss Curve
(First Year of Disruption)



Source: Projected data: The dashed line represents EIA simulations prepared for the EIA Analysis Report (reference Chapter 7 footnote 4). The remaining points are simulation results of studies listed in Chapter 7 footnote 4.

- The models surveyed capture economic feedbacks to the world oil market in substantially different ways, imparting widely different world oil price effects to a given disruption.

- The elasticity of U.S. oil demand with respect to the change in the world oil price is a crucial variable that influences the ultimate affect on the U.S. economy, partly through effects on the oil import bill. Those models with higher elasticities tend to project smaller impacts.

- The monetary and fiscal policy reactions assumed in a disruption vary. Some researchers allow accommodating policy; others attempt to maintain neutrality by maintaining monetary and fiscal policies of the base case.

- The differing lag structures of the models surveyed influence the speed with which the economy reacts to the initial shock.

There is clear agreement in the context of these ranging analytic approaches that economic welfare in the United States is vulnerable to political events adversely affecting world oil supply.

Footnotes to Chapter 7

[1]The forecasts for high, middle, and low oil price cases are all smoothed trend forecasts based on modifications to the Data Resources, Inc., forecast of August 1983: TRENDLONG0883ANN.

[2]All references to economic projections for the midprice case in this chapter pertain to EIA projections, which include some feedbacks between the energy sector and the general economy. These differ slightly from the economic projections cited in the Executive Summary and Chapter 3, which pertain to assumed economic projections prior to incorporation of feedbacks.

[3]In the EIA forecasting methodology for projecting industrial energy demands, differences in feedback effects from energy are reflected even at the two-digit level for the industries in manufacturing. The basis for these differing feedbacks by specific manufacturing industry is as follows--industry sensitivities are based on observed historical variability of two-digit sectors over the last few business cycles, relative to the variability of manufacturing as a whole. Although this basis is simple, the relative changes to industrial growth rates predicted by this methodology are plausible, and improve the activity feedbacks to the projections for industrial energy demand.

[4]Energy Information Administration, Impacts of World Oil Market Stocks on the U.S. Economy, DOE/EIA-0411 (Washington, D.C., 1983).

[5]Stanford University, Macroeconomic Impacts of Energy Stocks: An Overview, EMF7.2, Energy Modeling Forum, (Stanford, Calif., 1984).

8. Energy Markets in the Longer Term

The variety of plausible energy scenarios becomes greater when longer time periods are considered. However, energy production and consumption patterns at the end of the century will still be heavily influenced by the inertia of present trends. With total energy use projected to grow at less than 2 percent per year through 1995 and the long lead times for construction projects, it is likely that a large share of the major energy-using facilities that will be in use at the end of the century have already been built. Similarly, with slowing population growth, most of the housing stock and other buildings likely to be in place at the end of the century have already been built. As a result, the likely long-term trends are very much dominated by the energy economy as it exists today and as projected through the mid-1990's. What, then, can be said about the possible changes in trends which may start to be apparent near the end of this century?

Oil and Gas

Contrary to the expectations in a large share of the forecasts made during the past decade, oil supply problems need not be a major constraint on basic economic growth in the United States in the longer term. Support for this view comes from the steady expansion of worldwide non-OPEC oil and gas exploration and the resulting increases in production capacity since the initial sharp oil price increase in 1973-74. Additional optimism for long-term supplies is provided by the fact that oil and gas exploration throughout most of the world outside of the United States has been comparatively modest by U.S. standards. As the last 10 years' experience has demonstrated, large oil price increases can lead to the development of additional supplies and significant conservation, albeit with a significant lag. It is highly unlikely that any major new discovery would permit oil consumption to grow at the rates of the 1960's, however.

If conventional petroleum were to become much more expensive than it is now, it is expected that a variety of known technologies would begin to replace current oil and gas production and processing--at significantly higher prices than are now paid for these energy sources.

The major intermediate-term alternative to conventional petroleum is natural gas. Out of 35 quadrillion Btu of oil forecast to be consumed in 1995, in Table A2, only about 4 can be replaced by gas relatively easily; most of the 4 is residual fuel, which is less important than other petroleum products to crude oil requirements. However, when a much wider range of uses in which natural gas can substitute for oil is considered, the potential resource base for oil users more than doubles. There is serious hope that natural gas supplies may be far larger than is generally expected. For instance, the technology for converting natural gas to methanol and even gasoline is well-established and vehicles using methanol instead of gasoline have been demonstrated.

In the longer term--if and when the world's conventional oil and gas supplies become much more expensive than now--petroleum product prices may be moderated by competition from unconventional heavy crude oils, shale oil, and tar sands. In addition, gasoline and other liquid and gaseous fuels can be produced from coal. Taking the possibilities for powering transportation--the major U.S. use for petroleum--a step further, electric and hybrid automobiles are an important possibility, because of basic research improving their range and capabilities.

The financial success of projects to displace conventional oil and gas is heavily dependent, however, on a high price for conventional petroleum and the achievement of significant economies in the production of the alternatives. The recent rapid abandonment of many projects that had been predicated upon further, rapid increases in oil prices--including a number of projects benefitting from significant subsidies--indicates that such oil prices are viewed as too uncertain or too distant to justify large-scale private investment. (Some of the synfuels projects may have been affected by environmental considerations as well; however, high-temperature synfuels technologies have been demonstrated which are more environmentally benign than the older Lurgi technology.) In the long term, it seems quite clear that even current technology could solve any potential liquid fuels problem. A steady rise in petroleum prices and continued research efforts would doubtless lead to improved technologies.

Other Energy Sources

One of the most significant projections in EIA forecasts is the persistent long-term trend toward an increasing share of electricity in end-use energy consumption. The means that electricity generation--whether by central coal, nuclear fission or fusion facilities, or more exotic means--is expected to be an increasingly important part of the energy economy. (It also suggests that the next transition in the use of alternative major energy sources, to either more coal and/or more unconventional methods of electric power generation, will require the solution to the acid rain problem, or major production technology problems, and/or national security problems associated with nuclear proliferation and potential terrorism.) This observation applies both to the United States and to the rest of the world. Thus, when examining the alternatives for long-term energy supply, much of the problem really involves the examination of long-term alternatives for electricity generation.

Although nuclear power is due for a very rapid near-term expansion because of commitments to plants that are currently under construction, coal is the strongest candidate to succeed petroleum as the principal domestically produced fuel. Most of the growth in coal use is expected to be derived directly from the expansion of the use of electricity. In other nations, nuclear power could experience a tremendous growth towards the end of the century, if economic growth is robust and the shift towards electricity is accelerated by higher oil prices. Other energy sources that currently produce electricity are hydropower--although most of the major, economically attractive hydroelectric sites in the United States are already in use--and geothermal energy. Both of these energy sources are highly regional in nature and limited in their potential output. Likewise, the potential for using wind power is highly limited.

Wood. The use of wood as an energy source for residential use apparently ended its long-term downward trend in the early 1970's and has more than doubled since then. It seems unlikely, however, that further large gains in wood energy use will occur unless oil prices increase more than is projected here. Transportation and environmental costs are major considerations. Wood is currently in use in situations where it is a low-cost local energy source: in the forest products industries, which produce wood wastes at the plant sites where these wastes are consumed as fuel, and for space heating in forested rural areas.

Solar. The outlook for solar power is more difficult to predict, because its future depends so heavily on technological progress and economic and sociological factors. Active solar power to heat or cool homes has very often proven to be too costly to be economically attractive. Passive solar design, when encouraged as an architectural standard, has the most economic potential for minimizing heating or cooling loads in well-designed structures. It is essentially free.

Solar cells to produce electricity (photovoltaics) are the most difficult of all uses for solar energy to project. At present, they are economic only in remote, special applications, where conventional sources of electricity would be very costly. However, their price continues to fall. Because their installation is relatively simple, their market penetration may be unusually rapid when and where they do become economic. Site availability may limit the output at present electricity prices, but there are some forms of photovoltaic technology (including revised proposals for satellite solar power) which may not be so constrained. Although there are many technical issues yet to be proven out in real hardware, it may turn out to be feasible to reduce the cost of photovoltaic electricity substantially soon after the turn of the century.

Advanced Nuclear. Other potentially significant longer term energy sources include the nuclear breeder reactor and fusion energy. Breeder reactors have been in operation in a number of countries, but the electric utility industry's current reluctance to plan for additional nuclear power plants makes the prospects for commercial breeder reactors in this country highly problematical. If the principal argument for a breeder reactor is the potential shortage of uranium, then the current and forseeable glut of uranium supplies and concern for the viability of U.S. uranium mining and milling industry at least postpones the economic viability of this technology.

Fusion energy has the potential for the production of significant amounts of energy for use at electric power stations. Currently, however, this process is only on the verge of demonstrating that it can be a net producer of controlled amounts of energy. Capital costs are unknown, but are likely to be high; construction lead-times are likely to be long. Thus, fusion energy appears to remain a potential commercial energy source only for 20 or more years in the future. Fusion reactors may also be used as breeders, to provide fuel for use in conventional nuclear reactors; this has important implications both for the economy and for national security.

Conservation. Finally, energy conservation can be counted on to continue to be the significant source of avoided fuel use. The world is still continuing to adjust to the use of more energy-efficient modes of production and consumption. There are many economically attractive investments that can, in total, yield important energy savings through relatively minor individual commitments. These include well-demonstrated methods of insulation, reducing air leakages from buildings, controlling heating and industrial process energy use and co-generation, using more-efficient vehicles. Improvements in the efficiency of energy use that are embodied in much of the capital equipment now in place can be expected to continue to yield energy savings well into the next century.

Conclusion

The fact that views of the future have been subject to major revisions at frequent intervals is one of the lessons relevant to the long term. More often than not, forecasts have overestimated long-term energy demand and underestimated the level and, therefore, adequacy of long-term supply. Consequently, forecasts have often overestimated the extent to which demand may bid up market prices. To summarize, based on the record of past forecasts, it is likely that there will be more supply and more conservation than have been recently estimated. What is not clear is the extent to which past perceptions that the supplies of energy will be inadequate may contribute to abundant long-term supplies.

9. Forecast Comparisons

The projections presented in this Annual Energy Outlook (AEO) reflect EIA's understanding of world and domestic energy markets and changes that are likely to evolve in the future. These projections have been updated from those in the 1982 AEO based on the continued downward trend in world oil prices, the strong signs of economic recovery, and other changes that have occurred in the interim. This section will discuss the major differences between the two consecutive AEO forecasts, as well as those among the 1983 AEO and four recently published forecasts of energy supply and demand. These other sources of projections were selected for comparison because they are widely circulated, well-documented, and sufficiently detailed to permit comparison and assessment.

In addition to the 1982 AEO, the four alternative forecasts are published in:

(1) Energy Review, Data Resources Inc., Winter 1983/1984. (DRI)

(2) Energy Analysis Quarterly, Chase Econometric Associates Inc., Fourth Quarter 1983. (Chase)

(3) Wharton Long-Term Forecast, Wharton Econometric Forecasting Associates, November 1983. (Wharton)

(4) Energy Projections to the Year 2010, A Technical Report in Support of the National Energy Policy Plan, U.S. Department of Energy, Office of Policy, Planning and Analysis, October 1983. (NEPP)

Forecast Analyses

Forecasts of energy supply and demand may differ for many reasons. Much of the variation can be attributed to differences in underlying assumptions concerning future OPEC pricing polices, economic growth rates, demand elasticities, and other key determinants of supply and demand. Differences in methodology and in the forecaster's view of the current and future market operations also result in different sets of projections, although the implications of these differences are more difficult to detect and to quantify. Additional deviations may arise due to differences in definitions, in conversion factors, and in the timing of the analysis; with respect to the latter, the forecasts considered for this comparative analysis were prepared late in 1983 and early in 1984, with the exception of the 1982 AEO and Energy Projections to the Year 2010.

This chapter first presents a broad view of the similarities and dissimilarities among the different forecasts. This is followed by a discussion of the differences in key assumptions and corresponding deviations in projections of domestic production, demand, imports, and exports.

General Similarities and Dissimilarities Among Forecasts

The general consensus among long-term energy forecasts is that there will be a substantial increase in total domestic end-use consumption from the 1983 level of 53 quadrillion Btu. A comparison of the 1990 projections for end-use energy consumption provides a range of 57 to 59 quadrillion Btu (Table 29). The range is also quite narrow on a primary consumption basis, with only a 3 quadrillion Btu differential among the alternative forecasts. The 1983 AEO projections for energy consumption and for the energy to GNP ratio fall in the middle of the ranges established by the forecasts selected for comparison.

The overall increase in end-use energy demand over time corresponds to expectations of modest increases in each of the four major consuming sectors. Industrial demands are expected to increase by the greatest amount, with projections as high as 25 quadrillion Btu in 1990 compared to 20 quadrillion Btu in 1983. There is less of a consensus on the future direction of changes in the transportation sector, but the forecasts prepared with the most recent data (1983 AEO, DRI, and Chase) indicate that product supplied for transportation purposes will increase over time.

On the supply side, domestic crude oil and natural gas production is expected to remain fairly constant over the decade. Rising wellhead prices for crude oil, and even more so for natural gas, help offset rising costs of production as resources become increasingly difficult to recover. Domestic energy requirements met with nuclear power and coal are projected to increase significantly as more nuclear power plants are brought on line and as industry and utilities increase their demands for coal inputs.

More rapid growth in demand than in domestic energy production projected for the rest of this decade would be met with increased levels of imports. The 1983 AEO midprice forecast for net oil imports in 1990 is close to 13 quadrillion Btu, which compensates almost entirely for the growing discrepancy between total domestic energy production and demands. The 1983 AEO high and low world oil price cases establish a range for net oil imports of 9 to 16 quadrillion Btu. The other published projections also indicate that dependence on foreign oil sources will increase relative to the low level of 9 quadrillion Btu realized in 1983. There does not appear to be any general agreement on the direction of change in natural gas imports or net coal, coke, and electricity exports among the different sets of forecasts.

Driving Assumptions

Differences in projections of energy supply and demand may be attributed in part to differences in basic assumptions as to the world oil price, economic activity, and various socio-economic and demographic factors. Table 30 presents the range of values for a number of key variables incorporated in the projections.

Growth in economic activity, as indicated by GNP, is expected to average close to 3.3 percent per year from 1983 to 1990, with anticipated growth in the industrial

Table 29. Comparison of Midprice Energy Supply/Demand Projections for 1990 (Quadrillion Btu per Year)

	AEO 1983	AEO 1982[a]	DRI Winter 83/84[b]	Chase IV/84[c]	Wharton November 83[d]	NEPP 1983[e]
Domestic Energy Supply						
Oil	20.8	19.3	20.0	17.9	18.7	19.0
Natural Gas	16.7	16.4	16.1	15.9	17.9	18.2
Coal	23.1	23.9	21.7	21.9	24.3	24.5
Hydroelectric/ Geothermal/Other	3.3	3.2	3.8	4.0	3.7	3.4
Nuclear Power	6.3	6.3	6.1	4.8	6.2	6.5
Total Domestic Production	70.3	69.1	67.7	64.5	70.8	71.6
Net Imports						
Oil	12.6	15.1	12.5	14.9	14.2	12.4
Natural Gas	1.3	1.2	2.2	2.4	0.8	1.9
Coal, Coke, and Electricity	-2.4	-3.4	-2.8	-2.2	-3.8	-3.2
Total Supply[f]	81.7	82.0	79.7	79.7	82.0	82.7
Consumption						
Residential	9.2	9.3	8.7	9.1	--	10.3
Commercial	7.1	6.9	6.4	6.1	--	7.2
Industrial	22.9	24.1	23.8	23.9	--	25.0
Transportation	19.5	16.9	19.0	19.1	--	16.7
Total End-Use Consumption	58.7	57.2	57.9	58.4	--	59.2

[a]Industrial total does not include natural gas as a lease and plant fuel.

[b]Industrial total excludes hydroelectric power, solar energy, and exotic energy forms but includes natural gas used for lease and plant fuel and as a raw material. Transportation total excludes natural gas used as a transportation fuel.

[c]Sectoral consumption totals exclude electricity conversion losses. Natural gas used as a pipeline fuel has been excluded from the transportation sector total.

[d]Electricity conversion losses incorporated in Wharton's sectoral energy consumption projections.

[e]Renewable energy consumption has been excluded from residential, commercial, and industrial totals. Natural gas used by the transportation sector has been excluded from that sector's total consumption.

[f]Total supply includes adjustments for stock changes, gains, losses, unaccounted-for supply, etc.

--=Not applicable.

Table 30. Comparison of Energy and Economic Growth Projections for 1990

	AEO 1983	AEO 1982	DRI Winter 83/84	Chase IV/83	Wharton November 83	NEPP 1983
Real Gross National Product (billions 1983 dollars) ..	4,169	4,082	4,171	4,183	4,057	4,150
Percent Change per Year (1983 to 1990)	3.3	3.0	3.3	3.4	2.9	3.3
Industrial Production (1967=100)	1.99	1.96	2.02	1.99	1.88	1.96
Percent Change per Year (1983 to 1990)	4.6	4.4	4.8	4.6	3.8	4.4
Real Personal Disposable Income (billions 1983 dollars) ..	2,904	2,821	2,864	2,914	2,787	(a)
Percent change per year (1983 to 1990)	2.9	2.5	2.7	3.0	2.3	(a)
Implicit Price Deflator (1983=1)	1.45	1.54	1.40	1.49	1.41	1.50
Percent Change per Year (1983 to 1990)	5.5	6.4	4.9	5.9	5.0	6.0
World Oil Price (1983 dollars)	36.65	38.40	31.19	29.07[b]	33.42	33.37
Passenger Vehicle-Miles (trillion)	1.66	1.73[c]	1.31	(a)	(a)	1.37
Average Fleet Efficiency (miles per gallon)	23.8	22.0[c]	20.4	(a)	(a)	24.9
Primary Energy Consumption (quadrillion Btu)	81.7	82.0	79.7	79.7	82.3	82.7[d]
Energy to GNP Ratio (1,000 Btu/1983$)	19.6	20.1	19.1	19.1	20.3	19.9

[a]Not available.
[b]Refiner acquisition cost average for domestic and imported crude oil.
[c]Includes light-duty trucks.
[d]End-use consumption of renewables by the residential, commercial, transportation, and industrial sectors deducted from NEPP primary energy consumption total.

sector ranging around 4.5 percent. Only the Wharton economic forecast stands out as distinctly less optimistic than the others, with the differences attributable to greater emphasis placed on the cyclic nature of the economy than is characteristic of the other forecasts.

The midprice projections in the 1983 AEO are based on a world oil price growing at less than 1 percent per year faster than the overall rate of inflation. The 1990 price of $36.65 is 4.6 percent lower than that predicted in the 1982 AEO. Correspondingly, the 1990 midprice forecast for total end-use consumption is 2.6 percent greater than in the previous year's analysis. The 1983 AEO high and low price cases are based on projections for the world oil price of 46 dollars and 29 dollars, respectively. The DRI, Chase, Wharton and NEPP analyses project less rapidly rising prices, with their base case price paths approaching the 1983 AEO low price estimates.

Demand Projections

The 1983 AEO projects a decline in the energy to GNP ratio from 21.3 in 1983 to 19.6 in 1990. This drop can be attributed in large part to improvements in efficiency as the capital stock is retrofitted or replaced over time. The other forecasts for the energy to GNP ratio range from 19.1 to 20.3, with Wharton's low GNP forecast corresponding to the high end of the range (Figure 43).

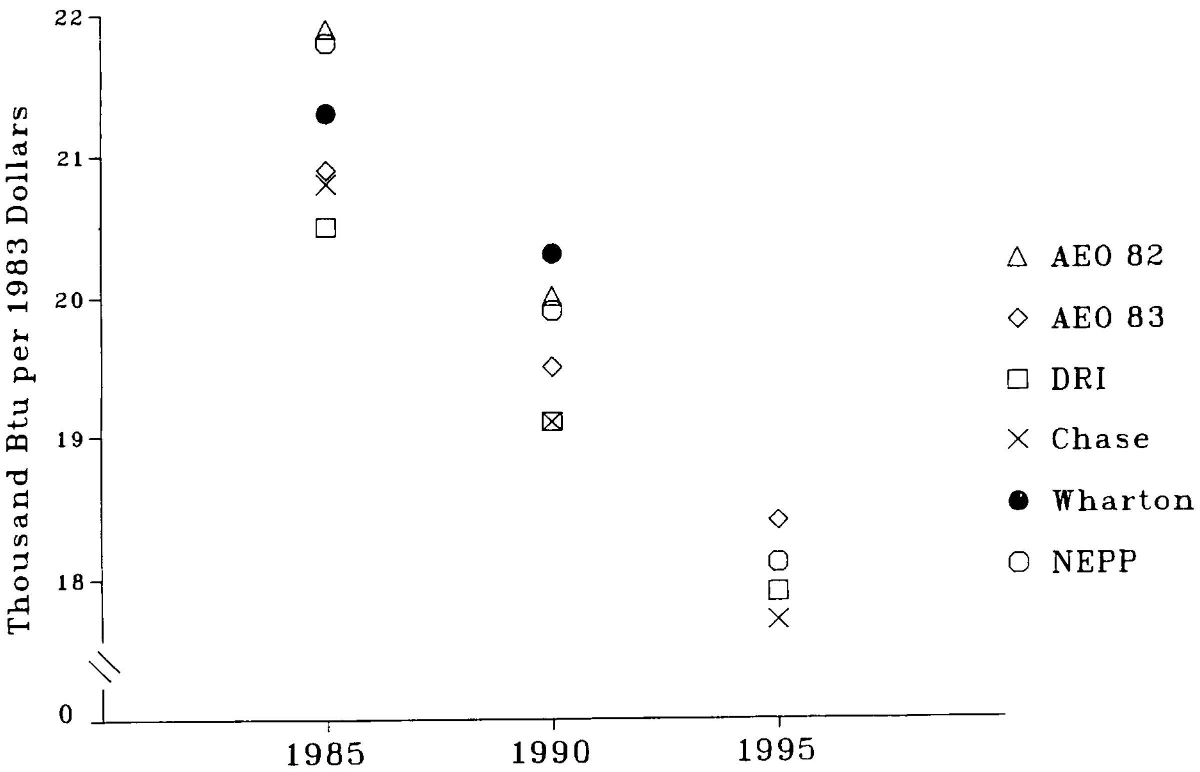
The general consensus of the analyses of residential and commercial sectors is that aggregate energy requirements will grow modestly for the rest of the decade, with only electricity consumption showing any significant gains relative to 1983 (Table 31). Projected average annual growth in electricity demand of 2.0 to 2.5 percent over the rest of the decade corresponds to expectations of essentially constant prices, as opposed to major increases in the cost of using gas or oil.

For the industrial sector, EIA, DRI, and Chase project industrial demand close to 23 quadrillion Btu compared to only 20 quadrillion Btu in 1983. Industrial demand projections have been adjusted downward in the recent past based on evidence of actual and potential conservation and efficiency gains.

Transportation demand projections for 1990 also have changed quite dramatically from the forecasts of less than 17 quadrillion Btu developed in 1982 or early 1983 (1982 AEO, NEPP) to more than 19 quadrillion Btu in the more recent forecasts. Apparent trends in consumer preferences back toward larger, less efficient cars, and recent evidence that car manufacturers are not likely to meet EPA Standards for 1990 have resulted in downward revisions in expected average fleet efficiency.

Finally, electric utilities are forecast to consume from 30 to 32 quadrillion Btu in 1990, up significantly from the 1983 rate of 25 quadrillion Btu per year. This increase in utility fuel consumption corresponds to the general view that demands for electricity will continue to grow in all end-use sectors as oil and gas prices rise more rapidly than electricity prices and as more electrical equipment is introduced into the home, office, and industry.

Figure 43. Comparisons of Projections for the Aggregate Energy/GNP Ratio



Sources: Historical data: Energy Information Administration, 1982 Annual Energy Outlook, DOE/EIA-0383(82) (Washington, D.C., 1983); Data Resources Inc., Energy Review, Winter 1983/1984 [DRI]; Chase Econometric Associates Inc., Energy Analysis Quarterly, Fourth Quarter 1983 [Chase]; Wharton Econometric Forecasting Associates, Wharton Long-Term Forecast, November 1983 [Wharton]; U.S. Department of Energy, Office of Policy, Planning, and Analysis, Energy Projections to the Year 2010, A Technical Report in Support of the National Energy Policy Plan, October 1983 [NEPP].

Table 31. Projections of U.S. Energy Demand by Sector for 1990 (Quadrillion Btu per Year)

Sector	AEO 1983	AEO 1982	DRI Winter 83/84	Chase IV/84	NEPP 1983[a]
End-Use Consumption					
Residential					
Oil and LPG	1.6	1.9	1.3	1.8	1.9
Natural Gas	4.6	4.3	4.4	4.4	5.3
Coal	0.1	0.1	0.1	0.1	0.1
Electricity	3.0	3.0	2.9	2.9	3.0
Total	9.2	9.3	8.7	9.1	10.3
Commercial					
Oil and LPG	1.3	1.5	0.9	0.9	1.1
Natural Gas	2.9	2.5	2.8	2.6	3.1
Coal	0.1	0.1	0.1	0.2	0.1
Electricity	2.8	2.8	2.5	2.5	2.8
Total	7.1	6.9	6.4	6.1	7.2
Industrial					
Oil and LPG	9.3	10.7	9.2	9.3	9.4
Natural Gas	6.6	6.0[b]	7.2	7.8	8.5
Coal	3.5	3.6	3.8	3.2	3.6
Electricity	3.5	3.8	3.6	3.5	3.5
Total	22.9	24.1	23.8	23.9	25.0
Transportation[c]					
Oil and LPG	19.5	16.9	19.0	19.1	16.7
Electric Utility					
Oil	1.6	4.0	2.2	2.0	2.0
Natural Gas	3.3	2.4	3.0	2.7	2.6
Coal	16.5	16.3	14.6	16.1	17.3
Nuclear Power	6.3	6.3	6.1	4.8	6.5
Other[d]	3.7	3.2	4.3	3.9	3.5
Total	31.4	32.2	30.2	29.5	31.9

[a]Renewable energy consumption excluded from all but the electric utility sector totals.

[b]Lease and plant fuel excluded from industrial natural gas end-use consumption.

[c]Pipeline gas not included under transportation end-use demand.

[d]Includes hydroelectric, geothermal, and other (woodwastes, solar, wind).

Supply Forecasts

Forecasts of total domestic energy production for 1990 range from 65 quadrillion Btu to 71 quadrillion Btu. Out of this total, the 1983 AEO forecast for oil production in excess of 20 quadrillion Btu is the most optimistic. The AEO projections for other sources of domestic production fall within the range established by the other forecasts.

The 1983 AEO midprice case projects net oil imports to grow from 8.6 quadrillion Btu in 1983 to 13 quadrillion Btu in 1990. The AEO forecast for total oil and gas imports falls below those published in the other sets of projections, corresponding to expectations of higher levels of domestic production.

Increasing competition in the world coal market has resulted in less growth in coal exports in 1983 than previously had been anticipated. This competition is expected to become even more intense in years to follow, resulting in downward revisions in the long-term coal export forecast.

Conclusion

The preceding discussion and tables highlight some of the principal differences in assumptions and in results among the major published forecasts. Despite significant differences in methodology and in critical assumptions such as the world oil price path, projections of total energy consumption for 1990 vary by only a few quadrillion Btu. However, a more detailed comparison of the projections indicates some significant differences with respect to demands by sector and anticipated domestic production capabilities. The breadth and complexity of the individual models upon which these projections were based renders a full analysis of the sources of differences among forecasts beyond the scope of this report.

Appendix A
Midprice and Sensitivity Case Reports

Appendix A
Midprice and Sensitivity Case Reports

Guide to Key Tables

This section of the Annual Energy Outlook, 1983 contains the tables comprising the EIA projections for total U.S. energy supply and disposition, as related to the world price of oil. Three case projections, A, B, and C, are developed for a middle, low, and high world oil price, respectively, and are placed in tables and appendixes correspondingly lettered following this guide. In this "Guide to Key Tables," these appendix tables are listed by number only, but in the tables are preceded by the letter A, B, or C, indicating which world oil price was used in developing that scenario table, and in what appendix they appear.

Appendix table 1 provides national summaries of energy supply and disposition by major fuel category. This table presents the basic energy balance summarizing the detail found in subsequent fuel or sector specific tables. Appendix table 2 expands the supply detail given in appendix table 1 by also listing net storage withdrawals and available supplies of major fuels. Disposition totals found in appendix table 1 are also listed in appendix table 3, but by major end-use sector. Appendix table 4 lists consumption totals for the same end-use sectors, but gives a greater breakdown for certain fuel categories. The corresponding prices for these sector/fuels are in appendix table 5. Appendix tables 6 through 9 provide detailed energy projections for the residential, commercial, industrial, and transportation end-use sectors by subsector or subfuel category. Electric utility summaries are given in appendix tables 10 through 14 for prices, consumption, capacity, and generation.

Petroleum supply, disposition, and prices are provided in appendix tables 15 and 16. Supply and disposition balances for natural gas and coal are given in appendix tables 17 and 18. All appendix tables are developed for each case, except appendix table 19, which only is listed after case A, and is a listing of important national macroeconomic indicators. Where prices are given in these appendix tables, 1983 dollars are used.

International energy use and supply projection tables appear directly in Chapter 2. They are described briefly at the end of this guide.

The following is an outline of each appendix table:

Supply and Demand Balances

Appendix Table 1 - Yearly Supply and Disposition Summary of Total Energy

This is the key balance table designed to be consistent with Table 1 of the Annual Energy Review, 1983. It provides:

- Production of major fuels
- Imports: crude oil, refined petroleum products, natural gas, other imports

- Exports: oil, natural gas, coal, other
- Consumption of major fuels
- Total Supply, Total Disposition.

Appendix Table 2 - Yearly Supply and Disposition of Total Energy, Supply Detail

This table includes:

- World Oil Price
- Domestic Production: oil, natural gas, coal, nuclear power, hydro/other
- Imports: oil, natural gas, coal, other imports
- Net Storage Withdrawals
- Available Supply: oil, natural gas, coal, nuclear power, other supply.

Energy Consumption by Sector

Appendix Table 3 - Yearly Supply and Disposition of Total Energy, Disposition Detail

This table uses the same major fuel categories as in appendix table 2, but the consumption detail is subdivided into major end-use sector.

- Disposition: Exports, of major fuels
- Consumption: residential and commercial, industrial, transportation, and electric utility sectors
- Total Disposition.

Appendix Table 4 - Consumption by Major Fuels and End-Use Sectors

This table provides a detailed consumption breakdown for each sector in appendix table 3. Major fuels listed include: distillate, kerosene, liquid petroleum gas (LPG), natural gas, steam coal, and electricity. Sectors included are: residential, commercial, industrial, transportation, and electric utilities. Finally, total consumption for all fuels in all sectors is listed.

Appendix Table 5 - Prices by Major Fuels and End-Use Sectors

This table provides the sectoral composition of prices associated with appendix table 4. It includes:

- Prices by the same end-use sectors and fuels as in appendix table 4
- Average fuel prices in all sectors.

Tables 6 to 9 provide detailed consumption summaries for the residential, commercial, industrial, and transportation sectors, respectively. Each table gives a total for energy consumed in that sector, and is further subdivided into relevant categories of end-use and fuels consumed. These tables give fuel use in quadrillion Btu per year, plus the transportation sector appendix table gives consumption for certain fuels in billions of gallons.

Appendix Table 6 - Residential Energy Use by End-Use

This table is divided by major fuels used, and by application in the Residential Energy Consumption Survey showing: space heating, water heating, air conditioning, and other end uses. The major fuel categories include: LPG, fuel oil, natural gas, coal, and electricity.

Appendix Table 7 - Commercial Energy Use by Building Type

Appendix table 7 lists the following fuel categories: LPG, motor gasoline, fuel oil, natural gas, coal, and electricity. This table provides energy consumption detail by fuel for each building type in the Nonresidential Energy Consumption Survey:

- Office
- Retail/Wholesale
- Warehouse
- Other Buildings.

Appendix Table 8 - Industrial Energy Use

Industrial energy use projections follow the Annual Survey of Manufactures distinction between fuels used for heat and power and fuels used as feedstocks and raw materials. Energy consumption for this sector is listed under the categories:

- Industrial Heat and Power
- Refinery Fuel
- Fuels listed for the above two categories are: distillate, residual, LPG, natural gas, steam coal, and electricity
- Feedstock, Raw Materials, and Other Fuel Uses: motor gasoline, petroleum feedstocks, LPG, metallurgical coal, and other miscellaneous petroleum products.

Appendix Table 9 - Transportation Sector Energy Use by Mode

Transportation sector energy consumption projections are disaggregated consistently with Federal Highway Administration and Federal Aviation Administration data. The "truck" category is an aggregate of the Federal Highway Administration's categories "single unit trucks" and "combination trucks." For each forecast year, projections are provided for:

- Energy consumption in all travel modes. Listed include: distillate, residual, jet fuel, motor gasoline, natural gas, and electricity
- Fuel use in automobiles
- Fuel use in trucks
- Fuel use in air.

Appendix tables 10 to 14 are the electric utilities summaries. Projections include fuel prices, fuel consumption, sectoral and U.S. electricity prices and demands, available capacity, generation by plant type, and components of electricity price. Fuel prices are in 1983 dollars per million Btu, while electricity components of price are in 1983 dollars per thousand kilowatt-hours per year. Capacity projections are in gigawatts. In addition, appendix table 13 contains a list of capacity additions for each year, in megawatts.

Appendix Table 10 - Electric Utility Fuel Consumption and Electricity Sales

- Fuel Inputs: Quantities in quadrillion Btu of major fuels consumed by utilities in electric power generation
- Disposition of electric energy from utilities: Total electricity inputs, conversion losses, generation, and electricity sales
- Electricity Sales by End-Use Sector: residential, industrial, and commercial/other.

Appendix Table 11 - Electric Utility Sectoral Prices and Demands

- Sectoral prices: residential, commercial, and industrial
- Average prices for all sectors
- Electricity demand by major end-use sector
- Total U.S. demand for all sectors.

Appendix Table 12 - Electric Utility Capacity and Generation

This appendix table is divided into plant types, which are named by the fuels they utilize, including: coal steam, natural gas steam, oil steam, NG/oil steam, natural gas turbine, oil turbine, pumped storage hydropower, and nuclear power. This table provides information on:

- Available capacity by plant type
- Electricity generation by plant type
- Generation by Fuel Type: coal, natural gas, oil, nuclear power, and hydropower/other.

Appendix Table 13 - Electric Utility Capacity Additions

This appendix table lists capacity additions by major plant type according to fuel use under the following categories:

- Total Additions: Total projected capacity additions, (total of Pipeline and New Starts)
- Pipeline: Plants announced by utilities as being planned for construction, and or plants presently under construction. This category represents utility company estimates, not EIA projections.
- New Starts: Additional construction that is projected to be needed to meet forecast increases in demand.

Appendix Table 14 - Summary of Components of Electricity Price

- Components include capital, fuel, and operating and maintenance (O&M).
- Total Price: Projected average revenues per kilowatt-hour of demand for the total electric industry.

Fuel Balances

Appendix Table 15 - Petroleum Supply and Disposition Balance

- Production: crude oil, natural gas plant liquids, other domestic
- Imports: crude oil, refined products
- Imports include acquisitions for the Strategic Petroleum Reserve (SPR), which began in 1977.
- Exports: crude oil, refined products
- Primary Stock Changes: includes SPR stock changes for the years 1970-95
- Refined Petroleum Products: includes motor gasoline, jet fuel, kerosene, distillate, residual, LPG, other petroleum products
- Refined Petroleum Products Supplied to End-Use Sectors.

Appendix Table 16 - Petroleum Product Prices

This appendix table gives petroleum prices in 1983 dollars per barrel. It lists:

- Crude Oil Prices: world oil price and refinery aquisition cost
- Delivered Sector Product Prices to: residential and commercial, industrial, transportation, and electric utility users
- Refined Petroleum Products Prices, including for: motor gasoline distillate, residual, and jet fuel, LPG, and petroleum feedstocks.

Appendix Table 17 - Natural Gas Supply, Disposition, and Prices

Included here are data and projections for:

- Production: dry gas production and supplemental natural gas
- Net Imports;
- Total Supply
- Consumption by Sector: residential, commercial, industrial, lease and plant fuel, transportation, and electric utilities
- Average Wellhead Price
- Delivered Prices by Sectors: residential, commercial, industrial, and electric utilities.

Appendix Table 18 - Coal Supply, Disposition, and Prices

This table presents coal production projections in million short tons per year.

- Domestic production by region: East and West of the Mississippi
- Exports
- Total Supply
- Consumption by Sector: residential and commercial, industrial, coking plants, transportation, and electric utilities
- Delivered Prices by Sector (same as above).

Scenario Impact

Appendix Table 19 - National Macroeconomic Indicators

This table provides key macroeconomic variables. These include:

- Real GNP (in 1983 dollars)
- Real Disposable Income Per Capita
- GNP Price Deflator
- Total Industrial Production Index
- Gross Energy Use per Dollar of GNP.

The projections in the table represent the input macroeconomic assumptions. Also displayed are various energy usage indicators.

International Tables

The summaries of various international economic and energy indicators are located within chapter 2 in this publication in tables 1 to 12. The following is a brief description of each of these tables.

Table 1. - Annual Average Compound Growth Rates of Real Gross Domestic Product

This table provides annual average compound percentage growth rates of real gross domestic product for groups of countries in the OECD, for non-OECD countries, and for total market economies for the periods 1960 to 1973, 1973 to 1980, and projections for 1980 to 1990.

Table 2. - International Economic Growth

This table provides historical and short-term forecasts of economic growth rates for groups of countries in the OECD.

Table 3. - World Oil Prices, 1979 to 1995

This table provides world oil prices for 1979-83 and high, middle, and low world oil price projections through 1995. Prices are presented in constant 1983 dollars and in nominal dollars, and reflect the average landed price of crude oil in the United States.

Table 4. - Alternate Projections of OPEC Oil Production Capacities, 1984 to 1995

This table provides 1984 oil production capacities for each OPEC country and projections of low and high production capacities for each OPEC country for 1990 and 1995.

Table 5., 6., 7. - Market Economies of Oil Consumption and Production; History and Projections

These tables show oil consumption, production, net exports from Centrally Planned Economies (CPE's), and stock changes for 1980-83 and comparable projections under the mid, low, and high world oil price case for groups of countries in the Organization for Economic Cooperation and Development (OECD), for the Organization of Petroleum Exporting Countries (OPEC), and for all other market-economies countries taken as a group. The appropriate oil price case is specified in the table heading.

Table 8. - Market Economies Apparent Energy Consumption, History and Projections, Midprice Scenario

This table provides 1981 amounts and projections to 1995 of apparent primary energy consumption in quadrillion Btu under the world oil midprice case for groups

of countries in the OECD and the developing countries, and by five major fuel sources.

Table 9. - Market Economies Nuclear Generating Capacity, 1983-1990

This table provides 1983 nuclear generating capacity in gigawatts, and a range of projected capacities for the years 1985, 1990, and 1995 for the United States, other OECD countries, and non-OECD countries.

Table 10. - Comparison of EIA Projections from 1977 Through 1983, Midprice Scenario, 1990

This table presents midprice case projections of energy consumption in quadrillion Btu and oil consumption and production in million barrels per day for the year 1990 published by the Energy Information Administration (EIA) since 1977. Comparisons are presented for the United States and other market-economies countries or country groups. Corresponding world oil prices are listed in the footnotes.

Table 11. - Market Economies Energy Projections: Comparison of EIA Midprice Projections with other Projections for 1985, 1990, and 1995

This table compares midprice case projections for 1985, 1990, and 1995 of total energy consumption, and oil consumption and production in the market economies, and net oil exports from the CPE's with similar projections published recently by other organizations. Amounts for 1981 are also provided, and all values are in million barrels per day of oil equivalent.

Table 12. - World Oil Prices Sensitivity Analysis

This table provides sensitivity ranges for world oil price projections under a variety of scenarios for 1985, 1990, and 1995.

Location of Key Solution Values

Outlined below is a topical reference guide for the tables contained in appendices A, B, and C. It indicates where to find specific topics, including supply, demand, and prices of primary fuels and products. A "P" in parentheses indicates projections are in physical units, while an "S" denotes standard units (Btu). Note that the tables are referenced here only by number, but the actual designation in the appendices are A1 to A19, for tables in Appendix A, B1 to B18, for tables in Appendix B, and C1 to C18, for tables in Appendix C.

Domestic Supply

- Total Energy Production
  (1) Domestic energy production by major fuels, total production: Table 1(S)
  (2) Net storage withdrawals by major fuels: Table 2(S)
  (3) Available supply major fuels, total supply: Table 2(S).

- Oil
  (1) Total U.S. production: Tables 2(S), 15(P)
  (2) Crude oil: Tables 1(S), 15(P)
  (3) Refined petroleum products: Table 15(P).

- Natural Gas
  (1) Total U.S. production: Tables 1(S), 1(S), 17(P)
  (2) Available supply: Tables ((S), 17(P).

- Electricity
  (1) Electric utility generation: Tables 10(S), 12(P)
  (2) Capacity/generation by plant/fuel type: Table 12(P)
  (3) Nuclear: Tables 1(S)S, 12(P).

- Coal
  (1) Total U.S. production: Tables 1(S), 2(S), 18(P)
  (2) Available supply: Tables 2(S), 18(P)
  (3) Production by region: Table 18(P).

Domestic Disposition

- Total Energy Consumption
  (1) By major fuels: Tables 1(S), 4(S)
  (2) By end-use sector: Tables 3(S), 4(S)
  (3) End-use sector detail: Tables 6S,P), 7(S), 9(S,P).

- Oil
  (1) By end-use sector: Table 3(S)
  (2) Refined petroleum products: Tables 1(S), 4(S), 17(P).

- Natural Gas
  (1) Total U.S. consumption: Table 1(S)
  (2) By end-use sector: Tables 3(S), 4(S), 17(P).

- Electricity
  (1) Total U.S. consumption: Tables 4(S), 10(S)
  (2) By end-use sector: Tables 4(S), 11(P)

- Coal
  (1) Total U.S. consumption: Tables 1(S), 18(P)
  (2) By end-use sector: Tables 3(S), 4(S), 18(P).

Imports (Exports)

- Total oil: Table 2(S)
- Crude oil: Tables 1(S), 15(P)
- Petroleum products: Tables 1(S), 15(P)
- Natural gas: Tables 1(S), 2(S), 17(P)
- Electricity: Tables 1(S), 2(S)
- Coal: Tables 1(S), 18(P).

Prices

- To end-use sectors for major/minor fuels: Table 5(S)
- World oil price: Table 16(P)
- Petroleum products: Table 16(P)
- Natural gas: Table 17(P)
- Electricity: Tables 11(S), 14(P)
- Coal: Table 18(P).

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Middle World Oil Price Forecast
Case A

The following is the established base case forecast. Unless otherwise noted, the discussion in the text refers to the Case A projections. Key assumptions for the middle world oil price forecast include:

	World Oil Price (1983 Dollars)	Real GNP (Billion 1983 dollars)	Total Industrial Production Index (1967=1.00)
1983	29.35	3,312	1.46
1984	27.79	3,471	1.57
1985	26.52	3,585	1.64
1986	25.56	3,705	1.71
1987	26.98	3,837	1.79
1988	30.62	3,959	1.87
1989	33.75	4,063	1.93
1990	36.65	4,167	1.98
1991	39.38	4,265	2.03
1992	42.45	4,353	2.08
1993	45.00	4,446	2.13
1994	47.61	4,544	2.19
1995	50.49	4,651	2.25

Table A1. Yearly Supply and Disposition Summary of Total Energy

(Quadrillion Btu per Year)

Total Supply and Disposition	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.3	18.3	18.5	18.5	18.4	18.6	18.8	18.5	17.9
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.1
Natural Gas[1]	22.2	19.5	16.3	17.5	16.9	16.7	16.7	16.8	16.7	16.7	15.3
Coal[2]	13.9	14.9	17.3	19.1	20.1	20.6	21.0	21.6	22.3	23.1	26.2
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[3]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Production	62.0	61.1	61.0	64.1	65.3	66.2	67.1	68.4	69.6	70.3	71.9
Imports											
Crude Oil[4]	6.9	13.5	7.0	8.6	8.9	9.3	9.9	9.9	9.7	10.1	12.1
Refined Petroleum Products[5]	6.6	4.4	3.5	3.8	3.7	3.8	3.9	4.0	4.0	4.2	4.3
Natural Gas[6]	1.1	1.0	1.1	.9	1.1	1.2	1.3	1.3	1.3	1.3	1.7
Other Imports[7]	.2	.4	.4	.4	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	14.0	14.7	15.4	15.5	15.4	16.0	18.5
Net Stock Withdrawals	-.4	.3	1.0	-.6	-.5	-.5	-.5	-.5	-.5	-.5	-.2
Adjustments[8]	-.1	-.6	.1	.4	.3	.3	.3	.4	.4	.4	.8
Total Supply[9]	76.3	80.0	74.2	77.5	79.1	80.7	82.4	83.8	84.9	86.1	90.9
Disposition											
Exports											
Oil	.5	.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[10]	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.0	31.3	31.5	32.2	32.7	33.0	33.1	33.3	35.0
Natural Gas	22.5	20.0	17.4	18.2	18.2	18.1	18.1	18.2	18.2	18.3	17.4
Coal[12]	12.9	13.7	15.8	17.1	17.7	18.1	18.5	19.0	19.5	20.1	22.9
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.7
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	74.2	78.0	70.5	73.9	75.2	76.8	78.3	79.6	80.7	81.7	86.1
Total Disposition	76.3	80.0	74.2	77.5	79.1	80.7	82.4	83.8	84.9	86.1	90.9

[1] Net dry natural gas: dry marketed production excluding nonhydrocarbon gases.
[2] Historical coal production includes bituminous, anthracite, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other includes geothermal power, wood refuse, and hydropower generated at electric utilities. Hydropower produced by the industrial sector is also included.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes imports of dry natural gas, liquefied natural gas, and supplemental natural gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces.
[9] Total supply is the sum of production, imports, adjustments, and net stock withdrawals.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available

SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System. Historical quantities thru 1983.

Table A2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	8.35	20.69	29.35	27.79	26.52	25.56	26.98	30.62	33.75	36.65	50.49
Domestic Production											
Oil[2]	22.1	20.7	20.5	20.6	20.8	20.9	20.7	20.9	21.1	20.8	20.0
Natural Gas[3]	22.2	19.5	16.3	17.5	16.9	16.7	16.7	16.8	16.7	16.7	15.3
Coal[4]	13.9	14.9	17.3	19.1	20.1	20.6	21.0	21.6	22.3	23.1	26.2
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[5]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Domestic Production	62.0	61.1	61.0	64.1	65.3	66.2	67.1	68.4	69.6	70.3	71.9
Imports											
Oil[6]	13.5	17.8	10.6	12.4	12.5	13.2	13.8	13.9	13.7	14.2	16.4
Natural Gas[7]	1.1	1.0	1.1	.9	1.1	1.2	1.3	1.3	1.3	1.3	1.7
Coal[8]	.0	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.3	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	14.0	14.7	15.4	15.5	15.4	16.0	18.5
Net Storage Withdrawals											
Oil	–.3	.5	.5	–.1	–.1	–.1	–.1	–.1	.0	–.1	–.1
Natural Gas	–.4	–.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.5	–.1	–.1	–.1	–.1	–.1	–.1	–.1	–.2
SPR Fill Rate Additions (-)[11]	.0	–.3	–.5	–.4	–.3	–.3	–.3	–.3	–.3	–.3	.0
Net Stock Withdrawals	–.4	.3	1.0	–.6	–.5	–.5	–.5	–.5	–.5	–.5	–.2
Available Supply[12]											
Oil	35.3	39.1	31.6	32.8	33.3	33.9	34.4	34.7	34.8	34.9	36.3
Natural Gas	22.8	20.3	17.9	18.4	18.1	18.0	17.9	18.0	18.0	18.1	17.0
Coal	14.2	15.2	17.8	19.0	19.9	20.5	21.0	21.5	22.2	22.9	26.1
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Other Supply[13]	3.1	3.4	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.7
Total Supply (before adjustments)	76.3	80.6	74.1	77.2	78.8	80.4	82.0	83.4	84.5	85.7	90.1
Adjustments[14]	–.1	–.6	.1	.4	.3	.3	.3	.4	.4	.4	.8
Total Supply	76.3	80.0	74.2	77.5	79.1	80.7	82.4	83.8	84.9	86.1	90.9

[1] Average refiners acquisition cost in 1983 dollars per barrel.
[2] Oil includes crude oil, lease condensate, natural gas plant liquids, and other domestic refinery production.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes both dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[NA] = Not available
SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984).
Historical prices thru 1981 and quantities thru 1983.

Table A3. Yearly Supply and Disposition of Total Energy, Disposition Detail

(Quadrillion Btu per Year)

Total Disposition	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[2]	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.6	2.7	2.8	2.8	2.8	2.8	2.6
Natural Gas	7.6	7.6	7.1	7.5	7.5	7.5	7.5	7.5	7.5	7.5	6.9
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	12.3	11.9	9.6	10.2	10.3	10.4	10.5	10.5	10.5	10.4	9.7
Industrial											
Oil[4]	9.1	9.9	7.8	8.6	8.7	8.9	9.0	9.2	9.2	9.3	10.0
Natural Gas[5]	10.4	8.5	6.7	6.8	6.7	6.7	6.7	6.7	6.6	6.6	5.9
Coal[6]	4.0	3.3	2.4	3.0	3.1	3.2	3.3	3.4	3.4	3.5	3.6
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	23.5	21.9	16.9	18.3	18.5	18.7	19.0	19.2	19.3	19.4	19.5
Transportation											
Oil[7]	17.8	20.0	18.4	18.5	18.8	19.2	19.5	19.5	19.5	19.5	19.8
Natural Gas[8]	.7	.5	.6	.9	.9	.9	.9	.9	.9	.9	.9
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	18.5	20.5	19.0	19.5	19.8	20.1	20.4	20.4	20.4	20.4	20.7
Electric Utilities											
Oil	3.5	4.0	1.5	1.6	1.4	1.4	1.4	1.5	1.5	1.6	2.6
Natural Gas	3.7	3.3	3.0	3.1	3.1	3.0	3.0	3.1	3.2	3.3	3.7
Coal	8.7	10.3	13.2	14.0	14.4	14.8	15.1	15.4	15.9	16.5	19.2
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[9]	3.0	3.2	4.0	3.8	3.6	3.6	3.7	3.7	3.7	3.7	3.7
Total Consumption	19.9	23.7	25.0	25.9	26.7	27.5	28.5	29.5	30.4	31.4	36.2
Total Disposition	76.3	80.0	74.2	77.5	79.1	80.7	82.4	83.8	84.9	86.1	90.9

[1] Consists primarily of refined petroleum products.
[2] Consists of coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt. road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available

SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA 0214(81) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1983.

Table A4. Consumption by Major Fuels and End Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.11	1.23	1.25	1.28	1.29	1.29	1.27	1.23	1.07
Kerosene	.23	.15	.07	.07	.08	.08	.08	.08	.08	.07	.06
Liquefied Petroleum Gas	.59	.52	.29	.25	.25	.26	.26	.26	.26	.25	.22
Natural Gas	4.98	4.98	4.60	4.64	4.63	4.62	4.62	4.61	4.60	4.57	4.28
Steam Coal	.11	.08	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity	1.98	2.30	2.56	2.59	2.65	2.72	2.79	2.86	2.94	3.02	3.40
Total	9.88	9.99	8.71	8.85	8.93	9.02	9.10	9.16	9.20	9.22	9.08
Commercial											
Distillate Fuel	.64	.67	.38	.43	.46	.49	.51	.53	.54	.55	.55
Kerosene	.06	.05	.05	.07	.07	.08	.08	.08	.09	.09	.10
Motor Gasoline	.09	.11	.09	.08	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.29	.38	.41	.43	.46	.48	.49	.50	.50
Liquefied Petroleum Gas	.10	.09	.05	.04	.04	.04	.04	.04	.04	.04	.04
Natural Gas[1]	2.65	2.64	2.49	2.83	2.86	2.88	2.90	2.90	2.90	2.88	2.67
Steam Coal	.15	.13	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity	1.52	1.81	2.12	2.32	2.41	2.50	2.58	2.66	2.73	2.81	3.16
Total	5.89	6.04	5.59	6.26	6.44	6.62	6.77	6.88	6.98	7.06	7.19
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.52	1.56	1.61	1.65	1.67	1.69	1.71	1.88
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Motor Gasoline	.26	.18	.13	.14	.14	.13	.12	.12	.11	.11	.09
Residual Fuel	1.86	1.72	.76	.95	1.00	1.04	1.05	1.02	1.00	.98	1.00
Liquefied Petroleum Gas	1.26	1.27	1.57	1.34	1.35	1.37	1.39	1.40	1.39	1.39	1.39
Petrochemical Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.20	1.23	1.25	1.26	1.26	1.27	1.33
Other Petroleum[4]	2.33	2.32	1.85	1.99	1.97	1.95	1.97	2.01	2.06	2.10	2.29
Natural Gas[5]	10.39	8.54	6.75	6.77	6.69	6.67	6.67	6.69	6.63	6.59	5.93
Steam Coal	1.54	1.40	1.46	1.70	1.78	1.86	1.93	1.99	2.04	2.09	2.18
Metallurgical Coal	2.45	1.86	.96	1.28	1.31	1.33	1.35	1.37	1.38	1.39	1.42
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Electricity	2.34	2.76	2.65	2.75	2.84	2.94	3.07	3.22	3.36	3.50	4.18
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	25.87	24.62	19.58	21.07	21.32	21.69	22.07	22.45	22.66	22.91	23.70

See footnotes at end of table.

Table A4. Consumption by Major Fuels and End Use Sectors —— Continued

(Quadrillion Btu per Year)

Sector and Fuel	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11
Distillate Fuel	2.22	2.68	2.83	2.68	2.78	2.92	3.07	3.22	3.38	3.54	4.54
Jet Fuel[6]	2.13	2.14	2.13	2.27	2.41	2.54	2.61	2.63	2.63	2.61	2.60
Motor Gasoline	12.46	13.93	12.46	12.59	12.58	12.64	12.64	12.50	12.32	12.14	11.34
Residual Fuel	.73	.99	.73	.66	.69	.72	.74	.76	.77	.78	.85
Liquefied Petroleum Gas	.02	.01	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.15	.26	.27	.28	.30	.31	.31	.32	.36
Natural Gas[7]	.74	.54	.57	.93	.92	.92	.92	.92	.92	.92	.87
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	18.56	20.55	18.97	19.49	19.76	20.12	20.38	20.44	20.45	20.45	20.69
Electric Utilities											
Distillate Fuel	.27	.28	.10	.12	.04	.02	.01	.02	.04	.05	.17
Residual Fuel	3.24	3.71	1.44	1.48	1.31	1.35	1.37	1.45	1.48	1.59	2.46
Natural Gas	3.75	3.30	3.01	3.08	3.15	3.02	2.98	3.11	3.20	3.30	3.69
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.79	15.07	15.42	15.92	16.45	19.19
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.02	3.18	3.95	3.80	3.58	3.64	3.65	3.67	3.68	3.69	3.70
Total	19.85	23.74	24.96	25.91	26.70	27.54	28.46	29.46	30.43	31.42	36.22
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.71	5.98	6.10	6.31	6.53	6.72	6.91	7.09	8.20
Kerosene	.45	.36	.27	.24	.25	.26	.26	.27	.27	.27	.25
Aviation Gasoline	.08	.07	.05	.08	.09	.09	.09	.10	.10	.10	.11
Motor Gasoline	12.80	14.21	12.69	12.82	12.80	12.85	12.84	12.70	12.52	12.34	11.51
Jet Fuel	2.13	2.14	2.13	2.27	2.41	2.54	2.61	2.63	2.63	2.61	2.60
Residual Fuel	6.49	6.95	3.22	3.47	3.41	3.54	3.62	3.70	3.74	3.85	4.81
Liquefied Petroleum Gas	1.98	1.89	1.94	1.64	1.65	1.67	1.69	1.70	1.70	1.69	1.65
Petrochemical Feedstocks	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.20	1.23	1.25	1.26	1.26	1.27	1.33
Lubricants and Waxes	.40	.41	.35	.52	.54	.56	.58	.59	.61	.62	.70
Other Petroleum	2.10	2.09	1.65	1.73	1.70	1.68	1.69	1.73	1.76	1.80	1.95
Natural Gas	22.50	20.00	17.42	18.24	18.24	18.12	18.08	18.24	18.25	18.26	17.43
Steam Coal	10.46	11.87	14.89	15.84	16.38	16.82	17.17	17.58	18.13	18.72	21.53
Metallurgical Coal	2.45	1.86	.96	1.28	1.31	1.33	1.35	1.37	1.38	1.39	1.42
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.06	3.21	3.99	3.83	3.61	3.67	3.69	3.70	3.71	3.72	3.74
Total Consumption	74.20	78.05	70.47	73.91	75.25	76.81	78.33	79.64	80.67	81.71	86.13
Electricity Consumption (all sectors)	5.84	6.89	7.33	7.66	7.91	8.17	8.45	8.75	9.04	9.35	10.76

[1] Commercial natural gas includes the Other category.
[2] Industrial includes all fuels consumed for heat and power, industrial feedstock and raw material uses, all fuels consumed by refineries, and natural gas used as lease and plant fuel.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of jet fuel, plant condensate, unfractionated stream, miscellaneous, natural gasoline, unfinished oils, special naphthas, asphalt, lubricants, waxes, petroleum coke, aviation blending components, motor gasoline blending components, and road oil.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA-0214 (82) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1981.

Table A5. Prices by Major Fuels and End Use Sectors
(1983 Dollars per Million Btu)

Sector and Fuel	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.37	5.13	7.88	7.56	7.30	7.11	7.37	8.06	8.68	9.29	12.12
Kerosene	3.85	5.94	8.28	7.94	7.67	7.47	7.74	8.46	9.11	9.74	12.69
Liquefied Petroleum Gas	7.40	6.86	8.80	8.60	8.45	8.39	8.54	8.93	9.34	9.85	12.13
All Petroleum Products	4.25	5.52	8.08	7.75	7.50	7.33	7.57	8.22	8.81	9.40	12.14
Natural Gas	2.60	3.62	5.80	5.86	6.01	6.16	6.38	6.65	7.00	7.38	10.67
Steam Coal[1]	2.39	3.66	2.05	2.10	2.13	2.16	2.18	2.21	2.25	2.28	2.60
Electricity	14.28	17.01	19.02	19.15	19.32	19.50	19.70	19.74	19.61	19.51	20.12
Average[2]	5.41	7.20	10.03	10.05	10.20	10.36	10.64	10.99	11.32	11.67	14.38
Commercial											
Distillate Fuel	2.78	4.53	6.42	6.10	5.84	5.65	5.90	6.59	7.21	7.81	10.62
Kerosene[3]	2.04	4.44	6.35	6.01	5.74	5.54	5.81	6.53	7.18	7.81	10.75
Motor Gasoline[4]	6.34	7.54	9.79	9.32	9.05	8.87	9.24	10.08	10.76	11.34	14.40
Residual Fuel	1.77	3.20	4.97	4.80	4.64	4.58	4.74	5.16	5.55	6.02	7.92
Liquefied Petroleum Gas	3.02	5.07	8.82	8.64	8.50	8.45	8.61	9.01	9.43	9.93	12.21
All Petroleum Products	2.54	4.29	6.44	5.97	5.73	5.57	5.77	6.34	6.86	7.39	9.84
Natural Gas[5]	1.89	3.16	5.42	5.45	5.55	5.67	5.88	6.14	6.47	6.83	10.04
Steam Coal[6]	.90	1.97	2.01	2.06	2.09	2.11	2.13	2.16	2.19	2.22	2.53
Electricity	13.51	16.83	19.20	19.35	19.55	19.74	19.96	20.03	19.90	19.81	20.59
Average[2]	5.03	7.51	10.73	10.61	10.75	10.91	11.17	11.47	11.73	12.02	14.53
Industrial											
Distillate Fuel	1.89	4.04	6.38	6.06	5.80	5.61	5.86	6.55	7.17	7.77	10.58
Kerosene	2.04	4.44	6.81	6.47	6.21	6.01	6.27	7.00	7.65	8.28	11.22
Motor Gasoline[4]	6.34	7.54	9.79	9.30	9.03	8.85	9.22	10.06	10.74	11.32	14.38
Residual Fuel	1.63	3.01	4.12	3.95	3.78	3.72	3.89	4.31	4.71	5.18	7.08
Liquefied Petroleum Gas	2.71	4.44	6.70	6.50	6.36	6.31	6.47	6.88	7.29	7.80	10.11
Petrochemical Feedstocks[7]	1.89	4.04	5.91	5.56	5.28	5.07	5.34	6.07	6.72	7.35	10.27
Still Gas[8]	1.89	4.04	6.29	5.97	5.71	5.52	5.78	6.47	7.09	7.70	10.52
Other Petroleum[9]	2.91	5.07	5.08	5.01	4.90	4.86	5.01	5.37	5.74	6.14	8.18
All Petroleum Products	2.34	4.22	5.92	5.62	5.41	5.28	5.49	6.05	6.56	7.10	9.58
Natural Gas[10]	.99	2.41	4.18	4.19	4.33	4.42	4.62	4.88	5.20	5.56	8.64
Steam Coal	.94	1.97	1.88	1.94	1.98	2.02	2.06	2.09	2.13	2.17	2.52
Metallurgical Coal	1.44	2.88	2.30	2.35	2.38	2.40	2.42	2.45	2.48	2.50	2.72
Net Coke Imports	3.31	7.30	6.52	6.65	6.76	6.82	6.88	6.95	7.03	7.10	7.71
Electricity	7.05	10.94	16.20	16.30	16.46	16.64	16.83	16.85	16.73	16.62	17.15
Average[2]	2.02	4.07	6.18	6.01	6.03	6.06	6.27	6.63	6.98	7.34	9.60

See footnotes at end of table.

Table A5. Prices by Major Fuels and End Use Sectors —— Continued

(1983 Dollars per Million Btu)

Sector and Fuel	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[11]											
Aviation Gasoline	7.70	10.14	12.89	12.33	11.87	11.57	12.18	13.61	14.76	15.73	20.91
Distillate Fuel	3.23	4.76	8.67	8.34	8.08	7.89	8.15	8.84	9.46	10.07	12.88
Jet Fuel[12]	1.98	4.38	6.75	6.38	6.09	5.85	6.14	6.87	7.52	8.15	11.08
Motor Gasoline[13]	6.34	7.54	9.79	9.30	9.03	8.85	9.21	10.05	10.73	11.31	14.37
Residual Fuel[14]	1.31	2.17	3.36	3.18	3.03	2.97	3.13	3.55	3.95	4.42	6.33
Liquefied Petroleum Gas[15]	2.71	4.44	8.13	7.94	7.80	7.75	7.91	8.31	8.72	9.23	11.50
Lubricants and Waxes[16]	12.10	14.42	22.68	22.13	21.69	21.36	21.80	22.99	24.04	25.08	29.89
All Petroleum Products	5.28	6.63	9.13	8.78	8.49	8.29	8.60	9.39	10.05	10.63	13.56
Natural Gas[17]	.50	1.27	2.53	2.53	2.61	2.61	2.77	2.97	3.23	3.52	6.13
Electricity	13.17	16.55	18.47	18.57	18.79	19.00	19.20	19.28	19.15	19.06	19.89
Average[2]	5.09	6.50	8.93	8.49	8.22	8.03	8.35	9.11	9.74	10.32	13.26
Electric Utilities											
Distillate Fuel[18]	2.19	3.89	6.94	6.37	6.29	6.02	6.18	6.87	7.55	8.10	10.71
Residual Fuel	1.59	3.05	4.28	4.10	3.97	3.91	4.09	4.52	4.94	5.44	7.37
All Petroleum Products	1.64	3.11	4.46	4.27	4.05	3.94	4.10	4.55	5.01	5.53	7.59
Natural Gas	.76	2.04	3.37	3.37	3.44	3.41	3.56	3.84	4.16	4.49	7.05
Steam Coal	.94	1.85	[19] 1.72	1.78	1.82	1.83	1.85	1.86	1.88	1.90	2.13
Fossil Fuel Average	1.05	2.17	2.24	2.26	2.25	2.23	2.27	2.37	2.46	2.58	3.41
Average Price to All Users											
Distillate Fuel	2.88	4.63	7.82	7.40	7.16	6.97	7.24	7.94	8.57	9.19	12.06
Kerosene	2.96	5.07	7.11	6.80	6.52	6.31	6.56	7.28	7.91	8.53	11.42
Aviation Gasoline	7.70	10.14	12.89	12.33	11.87	11.57	12.18	13.61	14.76	15.73	20.91
Motor Gasoline	6.34	7.54	9.79	9.30	9.03	8.85	9.21	10.05	10.73	11.31	14.37
Jet Fuel	1.98	4.38	6.75	6.38	6.09	5.85	6.14	6.87	7.52	8.15	11.08
Residual Fuel	1.59	2.93	4.10	3.96	3.81	3.75	3.92	4.35	4.75	5.24	7.19
Liquefied Petroleum Gas	2.71	4.44	6.70	6.50	6.36	6.31	6.47	6.88	7.29	7.80	10.11
Petrochemical Feedstocks	1.89	4.04	5.91	5.56	5.28	5.07	5.34	6.07	6.72	7.35	10.27
Lubricants and Waxes	12.10	14.42	22.68	22.13	21.69	21.36	21.80	22.99	24.04	25.08	29.89
Other Petroleum Products	1.89	4.04	5.41	5.06	4.81	4.62	4.85	5.48	6.05	6.62	9.31
All Petroleum Products	3.88	5.41	7.86	7.45	7.22	7.04	7.31	7.98	8.56	9.10	11.65
Natural Gas	1.39	2.71	4.58	4.58	4.70	4.79	4.99	5.24	5.56	5.91	8.88
Coal	1.05	2.02	1.78	1.84	1.88	1.90	1.92	1.93	1.95	1.98	2.21
Electricity	11.18	14.53	18.05	18.19	18.36	18.54	18.74	18.76	18.63	18.51	19.11
Average	3.20	4.91	6.72	6.54	6.51	6.50	6.71	7.07	7.38	7.68	9.50

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer mark-up.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Historical price for commercial kerosene is the price of industrial kerosene.
[4] Historical price for commercial and for industrial motor gasoline is the price of transportation motor gasoline.
[5] Commercial natural gas price is a weighted average of the commercial and other category.
[6] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer mark-up, where applicable.
[7] Industrial distillate price is used in historical years (through 1981).
[8] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[9] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[10] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[11] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[12] Jet fuel price is for kerosene type jet fuel at retail.
[13] Gasoline price is an average for all types.
[14] Residual fuel price is for marine bunker.
[15] Historical price for transportation LPG is the price of industrial LPG.
[16] Historical price is the price of industrial lubricants.
[17] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[18] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.
[19] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated actual average coal price is $1.66 per million Btu.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1*, (DOE/NBB-0029)/1 (Washington, D.C., 1982), pp. 229-95, Tables, C1 through C29. Projected prices are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981.

Table A6. Residential Energy Use by End Use

(Quadrillion Btu per Year)

Fuel and End Use	Midprice								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Total Fuel Use									
Space Heating	4.51	4.61	4.65	4.69	4.72	4.72	4.70	4.65	4.23
Water Heating	1.65	1.64	1.65	1.66	1.67	1.69	1.70	1.71	1.76
Air Conditioning	.37	.38	.39	.40	.41	.42	.43	.44	.49
Other End Uses[2]	2.17	2.20	2.23	2.26	2.29	2.33	2.37	2.41	2.60
Total	8.71	8.84	8.92	9.01	9.10	9.16	9.19	9.21	9.08
Liquefied Petroleum Gas									
Space Heating	.21	.18	.18	.18	.18	.18	.18	.17	.14
Water Heating	.09	.07	.07	.08	.08	.08	.08	.08	.08
Total	.29	.25	.25	.26	.26	.26	.26	.25	.22
Fuel Oil[3]									
Space Heating	.96	1.06	1.09	1.11	1.13	1.12	1.10	1.07	.89
Water Heating	.22	.24	.24	.24	.24	.24	.24	.24	.24
Total	1.18	1.30	1.32	1.35	1.37	1.36	1.34	1.31	1.13
Natural Gas									
Space Heating	3.03	3.06	3.05	3.05	3.04	3.03	3.01	2.98	2.68
Water Heating	1.01	1.02	1.02	1.02	1.02	1.02	1.02	1.03	1.03
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.01	.01
Other End Uses[2]	.54	.55	.55	.55	.55	.55	.55	.55	.55
Total	4.60	4.64	4.63	4.62	4.62	4.61	4.60	4.57	4.28
Coal									
Space Heating	.08	.07	.07	.07	.06	.06	.06	.06	.05
Total	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity									
Space Heating	.23	.25	.27	.28	.30	.32	.34	.36	.46
Water Heating	.33	.31	.32	.33	.34	.35	.36	.37	.42
Air Conditioning	.36	.37	.38	.39	.40	.41	.42	.43	.48
Other End Uses[2]	1.64	1.65	1.68	1.71	1.75	1.78	1.82	1.86	2.05
Total	2.56	2.59	2.65	2.72	2.79	2.86	2.94	3.02	3.40
Non-Marketed Fuel Consumption[1]									
Wood	0.89	0.92	0.94	0.96	0.97	0.98	1.00	1.01	1.11
Residential Activity									
Occupied Housing Stock (million units)	85.0	86.5	88.1	89.6	91.2	92.9	94.6	96.2	103.8
New Housing Construction[4] (million units)	1.5	2.0	2.0	2.0	2.0	2.1	2.1	2.1	1.9
Income Per Household (thousand 1983 dollars)	21.1	21.7	22.0	22.3	22.6	22.6	22.7	22.8	23.3
Energy Use Per Household (million Btu)	103	102	101	101	100	99	97	96	87
Fuel Expenditure Per Household (1983 dollars)	1,026	1,025	1,031	1,040	1,059	1,082	1,099	1,116	1,256

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multi-family, and mobile housing units.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration, DOE/EIA-0409, July 1983. The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.

Table A7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	Midprice								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	5.60	6.26	6.44	6.61	6.76	6.88	6.98	7.06	7.19
Liquefied Petroleum Gas	.05	.04	.04	.04	.04	.04	.04	.04	.04
Motor Gasoline	.09	.08	.08	.08	.08	.08	.08	.08	.08
Fuel Oil[1]									
Office[2]	.25	.30	.32	.33	.35	.36	.37	.38	.38
Retail/Wholesale	.16	.19	.20	.22	.23	.23	.24	.24	.23
Warehouse	.12	.15	.16	.18	.19	.20	.21	.22	.25
Other Buildings[3]	.20	.24	.26	.27	.28	.29	.30	.30	.29
Total	.73	.88	.94	1.00	1.05	1.09	1.12	1.14	1.14
Natural Gas									
Office[2]	.70	.80	.81	.81	.82	.82	.82	.81	.76
Retail/Wholesale	.70	.82	.83	.85	.86	.86	.87	.87	.84
Warehouse	.37	.39	.39	.39	.40	.39	.39	.39	.36
Other Buildings[3]	.72	.83	.83	.83	.83	.83	.82	.81	.71
Total	2.49	2.83	2.86	2.88	2.90	2.90	2.90	2.88	2.67
Coal	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity									
Office[2]	.81	.88	.92	.95	.98	1.01	1.04	1.07	1.20
Retail/Wholesale	.59	.67	.70	.73	.75	.78	.80	.83	.94
Warehouse	.30	.31	.33	.34	.35	.36	.37	.39	.44
Other Buildings[3]	.42	.45	.46	.48	.49	.50	.52	.53	.58
Total	2.12	2.32	2.41	2.50	2.58	2.66	2.73	2.81	3.16
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.7	50.7	52.3	53.9	55.4	56.7	58.0	59.3	65.7
Office[2]	17.1	17.8	18.4	19.0	19.5	20.0	20.4	20.9	23.2
Retail/Wholesale	14.5	15.3	15.8	16.4	16.9	17.3	17.8	18.2	20.4
Warehouse	6.9	7.2	7.4	7.7	7.9	8.1	8.3	8.5	9.5
Other Buildings[3]	10.1	10.4	10.6	10.9	11.1	11.3	11.5	11.7	12.6
Energy Use Per Square Foot (thousand Btu)	115.1	123.5	123.1	122.7	122.2	121.3	120.3	118.9	109.4
Expenditures Per Square Foot (1983 dollars)	1.20	1.28	1.30	1.31	1.34	1.37	1.39	1.40	1.56

[1] The commercial fuel oil category includes kerosene, distillate oil, and residual oil.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
SOURCE: The Commercial model is documented in *A Model of Commercial Energy Use Based Macroeconomic Data*, Brookhaven National Laboratory, April 1983. The major model source is the public use tape of the Non-Residential Energy Consumption Survey 1980, Energy Information Administration.

Table A8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.51	1.56	1.60	1.64	1.66	1.68	1.70	1.87
Residual Fuel	1.58	1.40	.65	.83	.88	.92	.92	.90	.88	.86	.87
Liquefied Petroleum Gas	.11	.16	.64	.33	.34	.34	.34	.35	.34	.35	.36
Natural Gas	8.50	7.08	5.56	5.52	5.44	5.41	5.39	5.41	5.35	5.30	4.65
Steam Coal[1]	1.54	1.40	1.46	1.70	1.78	1.86	1.93	1.99	2.04	2.09	2.18
Electricity[2]	2.34	2.76	2.54	2.64	2.73	2.83	2.96	3.11	3.24	3.39	4.06
Total	15.51	14.51	12.14	12.54	12.72	12.95	13.19	13.41	13.54	13.70	14.00
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.11	.11	.12	.12	.12	.12	.12	.12	.12
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.03
Still Gas	1.07	1.29	1.12	1.20	1.20	1.23	1.25	1.26	1.26	1.27	1.33
Petroleum Coke	.40	.39	.30	.30	.30	.30	.31	.31	.31	.31	.33
Other Petroleum	.00	.00	.01	.01	.01	.01	.01	.01	.01	.01	.01
Electricity	NA	NA	.11	.11	.11	.11	.11	.11	.11	.11	.12
Natural Gas	1.11	.82	.69	.69	.69	.71	.72	.73	.73	.74	.77
Total	2.93	2.93	2.37	2.46	2.47	2.52	2.57	2.59	2.59	2.60	2.74
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.13	.14	.14	.13	.12	.12	.11	.11	.09
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Petroleum Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Liquefied Petroleum Gas[4]	1.11	1.05	.90	.98	.99	1.00	1.01	1.02	1.02	1.01	.99
Special Naphthas	.17	.20	.15	.22	.23	.24	.25	.25	.25	.25	.26
Lubricants and Waxes	.23	.23	.20	.26	.27	.27	.28	.29	.29	.30	.34
Petroleum Coke	.16	.16	.16	.27	.29	.30	.30	.29	.28	.27	.25
Asphalt and Road Oil	1.26	1.16	.90	1.08	1.10	1.11	1.12	1.12	1.12	1.10	1.01
Other Raw Materials[5]	.11	.18	.13	-.15	-.22	-.28	-.30	-.26	-.20	-.15	.09
Metallurgical Coal[1]	2.45	1.86	.96	1.28	1.31	1.33	1.35	1.37	1.38	1.39	1.42
Natural Gas Raw Materials[6]	.78	.63	.49	.55	.55	.56	.56	.56	.55	.55	.50
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	7.43	7.18	5.07	6.07	6.13	6.21	6.32	6.45	6.53	6.61	6.96
Total Industrial Demand	25.87	24.62	19.58	21.07	21.32	21.69	22.07	22.45	22.66	22.91	23.70

[1] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[2] Includes refinery electricity before 1980.
[3] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[4] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[5] Other products includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components.
[6] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available

SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, D.C., 1984)
Historical quantities thru 1981.

Table A9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	Midprice								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.08	0.09	0.09	0.09	0.10	0.10	0.10	0.11
Distillate Fuel	2.83	2.68	2.78	2.92	3.07	3.22	3.38	3.54	4.54
Jet Fuel	2.13	2.27	2.41	2.54	2.61	2.63	2.63	2.61	2.60
Motor Gasoline	12.46	12.59	12.58	12.64	12.64	12.50	12.32	12.14	11.34
Residual Fuel	.73	.66	.69	.72	.74	.76	.77	.78	.85
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.15	.26	.27	.28	.30	.31	.31	.32	.36
Natural Gas	.57	.93	.92	.92	.92	.92	.92	.92	.87
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	18.97	19.49	19.76	20.12	20.38	20.44	20.45	20.45	20.69
Automobiles									
Vehicle-Miles Travelled[2]	1,155.1	1,250.7	1,343.3	1,439.5	1,521.1	1,576.3	1,620.9	1,660.5	1,833.2
Fleet-Miles per Gallon	16.5	17.5	18.6	19.7	20.8	21.8	22.8	23.8	27.9
Total Fuel Use[3]	69.9	71.5	72.1	72.9	73.1	72.2	71.0	69.8	65.7
Trucks									
Vehicle-Miles Travelled[2]	451.7	480.5	508.4	539.8	574.8	612.2	650.9	691.3	910.1
Fleet-Miles per Gallon	10.5	11.0	11.7	12.2	12.8	13.4	14.0	14.6	17.5
Total Fuel Use[3]	42.9	43.6	43.6	44.1	44.9	45.7	46.5	47.4	52.0
Air									
Revenue Passenger Miles[2]	290.6	324.2	363.1	401.3	431.0	448.4	462.2	473.5	542.5
Fuel Burned Per Seat Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	15.9	17.0	18.0	19.0	19.6	19.7	19.7	19.6	19.5
Aviation Gasoline[3]	.4	.7	.7	.7	.8	.8	.8	.8	1.0
Selected Fuel Expenditures[5]									
Motor Gasoline	122.1	117.1	113.6	111.8	116.4	125.6	132.2	137.3	162.9
Distillate Fuel	24.5	22.3	22.5	23.0	25.0	28.5	32.0	35.7	58.4

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1983 Dollars per Year.

Table A10. Electric Utility Fuel Consumption and Electricity Sales

(Quadrillion Btu per Year)

Fuel Consumption and Sales	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.12	0.04	0.02	0.01	0.02	0.04	0.05	0.17
Residual LS[1]	NA	NA	.81	.87	.86	.88	.91	.97	1.01	1.10	1.65
Residual HS[1]	3.24	3.71	.63	.61	.46	.47	.46	.48	.47	.48	.80
Natural Gas	3.75	3.30	3.01	3.08	3.15	3.02	2.98	3.11	3.20	3.30	3.69
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.79	15.07	15.42	15.92	16.45	19.19
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[2]	2.87	2.97	3.61	3.48	3.25	3.29	3.30	3.30	3.30	3.30	3.31
Total Fuel Inputs	19.70	23.53	24.61	25.59	26.37	27.20	28.11	29.10	30.05	31.03	35.83
Net Imports	.15	.20	.35	.32	.33	.34	.35	.36	.37	.39	.40
Total Electricity Inputs	19.85	23.74	24.96	25.91	26.70	27.54	28.46	29.46	30.43	31.42	36.22
Disposition											
Total Electricity Inputs	19.85	23.74	24.96	25.91	26.70	27.54	28.46	29.46	30.43	31.42	36.22
Minus Conversion Losses[3]	13.50	16.21	17.08	17.61	18.14	18.71	19.33	20.01	20.67	21.35	24.62
Equals Generation	6.35	7.53	7.88	8.30	8.56	8.83	9.13	9.44	9.75	10.07	11.61
Minus Transportation and Distribution Losses	.51	.64	.55	.64	.65	.66	.68	.70	.71	.73	.85
Equals Electricity Sales	5.84	6.89	7.33	7.66	7.91	8.17	8.45	8.75	9.04	9.35	10.76
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.59	2.65	2.72	2.79	2.86	2.94	3.02	3.40
Commercial/Other[4]	1.53	1.82	2.13	2.33	2.42	2.51	2.59	2.67	2.74	2.82	3.17
Industrial	2.34	2.76	2.65	2.75	2.84	2.94	3.07	3.22	3.36	3.50	4.18
Total Electricity Sales	5.84	6.89	7.33	7.66	7.91	8.17	8.45	8.75	9.04	9.35	10.76

[1] Prior to 1983, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available
SOURCE: Historical quantities thru 1983.

Table A11. Electric Utility Sectoral Prices and Demands

(Billion Kilowatthours per Year)
(1983 Dollars per Thousand Kilowatthours)

Prices and Demands	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	48.7	58.0	64.9	65.3	65.9	66.5	67.2	67.3	66.9	66.6	68.7
Commercial[2]	46.1	57.4	65.5	66.0	66.7	67.4	68.1	68.3	67.9	67.6	70.3
Industrial	24.1	37.3	55.3	55.6	56.2	56.8	57.4	57.5	57.1	56.7	58.5
All Sectors	38.1	49.6	61.7	62.1	62.7	63.3	63.9	64.0	63.6	63.2	65.2
Demands											
Residential	579	674	749	758	777	797	817	839	862	886	997
Commercial[2]	447	534	624	682	710	736	760	782	804	826	929
Industrial	686	809	776	806	832	863	899	943	984	1,027	1,226
All Sectors	1,713	2,018	2,149	2,246	2,318	2,395	2,476	2,565	2,650	2,739	3,153

[1] Prices for 1983-95 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price System, Volume 1*, DOE/NBB-0029/1, (Washington, D.C., 1982). Demands for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984).

Table A12. Electric Utility Capacity and Generation

(Generation in Billion Kilowatthours per Year)

(Capacity in Million Kilowatts)

Capacity and Generation	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	320.6	399.5	454.1	297.7	305.6	312.2	317.8	324.3	329.7	335.5	364.8
Natural Gas Steam	–	–	–	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Oil Steam	–	–	–	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
Natural Gas/Oil Steam	–	–	–	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8
Natural Gas Combined Cycle	–	–	–	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Oil Combined Cycle	–	–	–	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Natural Gas Turbine	38.4	54.5	56.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil Turbine	–	–	–	24.5	24.5	24.5	24.5	24.5	24.6	24.7	24.9
Natural Gas/Oil Turbine	–	–	–	24.7	24.7	24.8	24.8	24.9	25.2	25.5	38.8
Nuclear Power	21.0	53.5	66.0	73.6	84.8	94.3	104.3	104.8	107.1	110.8	119.2
Hydropower/Other[2]	62.4	71.6	80.3	69.9	71.3	72.0	72.1	72.5	72.6	72.6	72.7
Pumped Storage Hydropower[3]	–	–	–	14.3	15.4	16.4	18.3	18.8	18.8	18.8	18.9
Total Capacity	442.4	579.2	657.0	678.4	700.0	717.9	735.5	743.5	751.7	761.6	813.1
Generation by Plant Type[1]											
Coal Steam	1,467	1,610	1,662	1,351	1,398	1,434	1,463	1,498	1,548	1,601	1,872
Natural Gas Steam	–	–	–	54	56	59	62	65	67	68	69
Oil Steam	–	–	–	95	103	107	107	114	114	118	137
Natural Gas/Oil Steam	–	–	–	231	213	201	198	204	210	222	277
Natural Gas Combined Cycle	–	–	–	33	29	29	27	28	29	29	28
Oil Combined Cycle	–	–	–	1	1	0	0	0	1	1	1
Natural Gas Turbine	37	36	16	1	1	1	1	1	2	2	3
Oil Turbine	–	–	–	8	3	2	1	1	3	3	12
Natural Gas/Oil Turbine	–	–	–	6	7	5	5	7	8	10	42
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
Hydropower/Other[2]	274	283	338	342	320	326	328	330	330	330	330
Pumped Storage Hydropower[3]	–	–	–	-7	-7	-9	-11	-12	-12	-12	-12
Total Generation	1,861	2,206	2,309	2,433	2,508	2,588	2,675	2,768	2,859	2,952	3,402
Generation by Fuel Type											
Coal[4]	848	976	1,259	1,345	1,392	1,428	1,457	1,492	1,542	1,594	1,865
Natural Gas	341	305	274	284	290	280	275	288	295	303	329
Oil	314	365	145	151	129	130	131	140	144	155	246
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
All Hydropower/Other[5]	274	283	338	335	313	317	317	318	318	318	318
Total Generation	1,861	2,206	2,309	2,433	2,508	2,588	2,675	2,768	2,859	2,952	3,402

[1] Historical data for 1973, 1978, and 1983 are given by prime mover only. Thus for the historical period, all steam and combined cycle capacity and generation is shown in the coal steam category; all turbine and internal combustion capacity and generation are shown in the natural gas turbine category; and all conventional hydroelectric, pumped storage hydroelectric, and other renewable capacity and generation is shown in the hydropower/other category.

[2] This category includes other renewable sources such as geothermal, wood, waste, solar, and wind.

[3] See Appendix E, electricity terminology for definition of pumped storage plant.

[4] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[5] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal, wood, waste, solar, and wind.

- See footnote 1.

SOURCE: Data for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984). Capacity data for projection years 1984-95 are based on the Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table A13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	Midprice												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	5,922	5,264	5,820
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	1,648	2,753	2,934	3,405	2,818
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total New Capacity	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	10,275	12,802	11,153	8,670	8,638
Pipeline[6]													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	3,915	1,450	400
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	361	71	0	0	50
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total Pipeline	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	8,989	10,120	6,212	1,450	450
New Starts[7]													
Nuclear Power	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	2,007	3,814	5,420
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	1,287	2,682	2,934	3,405	2,768
Pumped Storage Hydro[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	0	0	0	0	0	0	0	0	1,287	2,682	4,941	7,220	8,188

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam capacity
[3] Includes all gas turbine and internal combustion capacity
[4] See Appendix E, electricity terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.

SOURCE: The Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table A14. Summary of Components of Electricity Price
(1983 Dollars per Thousand Kilowatthours)

Price Components	Midprice												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	24.5	24.7	25.2	25.9	26.5	26.1	25.0	23.7	22.8	21.9	20.9	20.1	19.2
Fuel Component[2]	22.2	22.4	22.2	21.8	21.9	22.5	23.3	24.2	25.4	26.7	28.4	29.9	31.3
O&M Component[3]	14.9	15.0	15.3	15.5	15.5	15.4	15.3	15.2	15.1	15.0	14.9	14.8	14.6
Total Price[4]	61.7	62.1	62.7	63.3	63.9	64.0	63.6	63.2	63.3	63.6	64.3	64.7	65.2

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.

Table A15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.65	8.65	8.67	8.71	8.66	8.72	8.80	8.63	8.11
Alaska North Slope	.00	1.09	1.64	1.65	1.71	1.80	1.86	1.86	1.91	1.81	1.31
Subarctic	9.21	7.62	7.02	7.00	6.96	6.91	6.80	6.86	6.89	6.82	6.80
Natural Gas Plant Liquids	1.74	1.57	1.56	1.58	1.64	1.63	1.61	1.60	1.61	1.61	1.46
Other Domestic[2]	.01	.01	.05	.05	.05	.05	.05	.06	.07	.09	.34
Processing Gain[3]	.45	.50	.48	.51	.49	.50	.51	.52	.52	.52	.54
Total Production	11.40	10.78	10.74	10.80	10.86	10.89	10.83	10.90	11.00	10.85	10.45
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.30	4.05	4.19	4.39	4.65	4.65	4.59	4.75	5.71
Refined Products	3.01	2.01	1.69	1.81	1.74	1.83	1.86	1.92	1.91	1.98	2.03
Total Imports	6.26	8.36	4.99	5.86	5.93	6.22	6.51	6.57	6.50	6.73	7.74
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.57	.54	.61	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.72	.78	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	6.02	8.00	4.25	5.14	5.15	5.44	5.73	5.79	5.72	5.95	6.96
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.26	-.06	-.04	-.06	-.05	-.04	-.02	-.03	-.04
SPR Fill Rate Additions (-) [6]	.00	-.16	-.23	-.17	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	17.29	18.87	15.02	15.71	15.82	16.12	16.36	16.50	16.55	16.62	17.37
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.70	6.68	6.70	6.70	6.62	6.53	6.43	6.00
Aviation Gasoline	.05	.04	.03	.05	.05	.05	.05	.05	.05	.06	.06
Jet Fuel[8]	1.06	1.06	1.04	1.11	1.18	1.24	1.28	1.28	1.28	1.28	1.27
Kerosene	.22	.18	.13	.12	.12	.12	.13	.13	.13	.13	.12
Distillate Fuel	3.09	3.43	2.68	2.80	2.87	2.97	3.07	3.16	3.25	3.33	3.85
Residual Fuel	2.82	3.02	1.40	1.51	1.49	1.54	1.58	1.61	1.63	1.68	2.10
Liquid Petroleum Gas	1.45	1.41	1.47	1.23	1.24	1.26	1.27	1.28	1.27	1.27	1.24
Petrochemical Feedstocks	.36	.59	.41	.64	.67	.70	.74	.77	.79	.82	.94
Other Petroleum Products[9]	1.59	1.70	1.37	1.54	1.54	1.55	1.57	1.60	1.62	1.65	1.79
Total Product Supplied	17.31	18.85	15.15	15.69	15.82	16.13	16.37	16.50	16.56	16.63	17.37
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.28	1.32	1.36	1.39	1.41	1.41	1.40	1.29
Industrial[10]	4.49	4.89	4.01	4.32	4.39	4.48	4.56	4.62	4.66	4.70	5.02
Transportation	9.03	10.13	9.31	9.39	9.52	9.70	9.82	9.84	9.83	9.82	9.92
Electric Utilities	1.54	1.75	.67	.70	.59	.60	.60	.64	.66	.72	1.15
Total End-Use Consumption	17.30	18.84	15.19	15.69	15.83	16.13	16.38	16.51	16.56	16.64	17.38
Discrepancy[11]	-.01	.03	-.17	.01	-.01	-.01	-.02	-.01	-.02	-.01	-.01
Net Disposition[12]	17.29	18.87	15.02	15.71	15.82	16.12	16.36	16.50	16.55	16.62	17.37

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.

NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.

SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1983.

Table A16. Petroleum Product Prices
(1983 Dollars per Barrel)

Sector and Fuel	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	8.35	20.69	29.35	27.79	26.52	25.56	26.98	30.62	33.75	36.65	50.49
Refinery Acquisition Cost[2]	8.50	17.93	29.35	27.79	26.52	25.56	26.98	30.62	33.75	36.65	50.49
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	18.78	28.99	43.75	41.81	40.24	39.06	40.48	44.46	47.99	51.46	67.62
Kerosene	19.55	31.42	42.33	39.88	38.21	36.93	38.29	42.25	45.75	49.20	65.36
Motor Gasoline[3]	33.32	39.58	51.45	48.95	47.53	46.61	48.51	52.95	56.53	59.56	75.67
Residual Fuel	11.15	20.10	31.27	30.18	29.16	28.78	29.80	32.41	34.90	37.84	49.82
Liquefied Petroleum Gas[4]	25.27	24.17	32.05	31.36	30.81	30.58	31.14	32.59	34.08	35.91	44.21
Average[5]	19.62	27.34	40.13	38.65	37.30	36.37	37.57	40.93	43.94	47.03	61.21
Industrial											
Distillate Fuel	10.99	23.54	37.18	35.28	33.77	32.65	34.12	38.16	41.75	45.27	61.62
Kerosene	11.56	25.19	38.61	36.70	35.19	34.06	35.58	39.69	43.35	46.95	63.62
Motor Gasoline[3]	33.32	39.58	51.45	48.86	47.43	46.51	48.41	52.84	56.42	59.45	75.53
Residual Fuel	10.25	18.90	25.93	24.83	23.80	23.40	24.44	27.09	29.61	32.58	44.51
Liquefied Petroleum Gas	10.14	16.30	24.39	23.70	23.18	22.98	23.57	25.05	26.57	28.43	36.82
Petrochemical Feedstocks[6]	10.54	22.80	33.29	31.16	29.62	28.43	29.96	34.04	37.66	41.20	57.60
Asphalt & Road Oil	12.51	26.82	24.67	24.04	23.47	23.26	23.85	25.36	26.78	28.47	35.34
Petroleum Coke	11.36	24.35	7.43	7.40	7.33	7.30	7.38	7.56	7.74	7.94	8.79
Special Naphthas	9.90	21.21	32.95	31.25	29.91	28.91	30.26	33.90	37.15	40.34	55.12
Miscellaneous Petroleum Products	11.78	25.03	32.51	30.42	28.90	27.80	29.16	32.94	36.36	39.79	55.93
Average[5]	11.58	21.75	28.15	27.09	26.10	25.49	26.50	29.19	31.71	34.40	46.93
Transportation[7]											
Distillate Fuel	18.80	27.70	50.47	48.58	47.09	45.98	47.46	51.51	55.11	58.64	75.03
Aviation Gasoline	38.87	51.21	65.05	62.24	59.91	58.40	61.49	68.68	74.49	79.41	105.53
Motor Gasoline[3]	33.33	39.58	51.45	48.85	47.41	46.48	48.38	52.80	56.37	59.40	75.46
Jet Fuel[8]	11.11	24.59	37.88	35.77	34.13	32.82	34.41	38.54	42.18	45.73	62.13
Residual Fuel[9]	8.21	13.67	21.13	20.02	19.02	18.65	19.67	22.30	24.80	27.76	39.80
Liquefied Petroleum Gas	10.14	16.30	29.60	28.94	28.43	28.23	28.82	30.28	31.77	33.61	41.91
Lubricants[10]	73.36	87.47	137.58	134.21	131.55	129.58	132.22	139.42	145.83	152.12	181.31
Average[5]	28.52	35.87	49.39	47.50	45.97	44.92	46.69	51.01	54.62	57.86	74.22
Electric Utilities											
Distillate Fuel	12.73	22.69	40.43	37.11	36.64	35.07	36.01	40.02	43.96	47.17	62.41
Residual Fuel	9.99	19.17	26.93	25.76	24.96	24.58	25.72	28.44	31.04	34.22	46.35
Average[5]	10.22	19.43	27.87	26.69	25.37	24.74	25.79	28.57	31.41	34.67	47.46
Refined Petroleum Product Prices											
Distillate Fuel	16.80	26.98	45.53	43.08	41.68	40.61	42.15	46.26	49.92	53.52	70.24
Kerosene	16.77	28.75	40.33	38.54	36.96	35.77	37.22	41.25	44.83	48.35	64.73
Aviation Gasoline	38.87	51.21	65.05	62.24	59.91	58.40	61.49	68.68	74.49	79.41	105.53
Motor Gasoline[3]	33.33	39.58	51.45	48.85	47.41	46.48	48.38	52.80	56.38	59.40	75.46
Jet Fuel[8]	11.11	24.59	37.88	35.77	34.13	32.82	34.41	38.54	42.18	45.73	62.13
Residual Fuel	9.98	18.39	25.76	24.90	23.92	23.55	24.63	27.33	29.88	32.96	45.17
Liquefied Petroleum Gas	15.49	18.83	25.83	25.08	24.55	24.34	24.93	26.39	27.90	29.74	37.98
Lubricants (Transportation)[10]	73.36	87.47	137.58	134.21	131.55	129.58	132.22	139.42	145.83	152.12	181.31
Petrochemical Feedstocks[6]	10.54	22.80	33.29	31.16	29.62	28.43	29.96	34.04	37.66	41.20	57.60
Asphalt & Road Oil	12.51	26.82	24.67	24.04	23.47	23.26	23.85	25.36	26.78	28.47	35.34
Petroleum Coke	11.36	24.35	7.43	7.40	7.33	7.30	7.38	7.56	7.74	7.94	8.79
Special Naphthas	9.90	21.21	32.95	31.25	29.91	28.91	30.26	33.90	37.15	40.34	55.12
Miscellaneous Petroleum Products	11.78	25.03	32.51	30.42	28.90	27.80	29.16	32.94	36.36	39.79	55.93

[1] Average cost of crude oil imported into the United States.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation* DOE/NBB-029)/1 (Washington, D. C., 1982) pp. 194-225, Tables B14 Through B29. Projected values are output from the Intermediate Future Forecasting System.
Historical prices thru 1981.

Table A17. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)

(1983 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.90	17.03	16.48	16.27	16.20	16.31	16.27	16.29	14.89
Supplemental Natural Gas[2]	.00	.00	.13	.01	.03	.06	.00	.02	.05	.08	.36
Net Imports	.96	.91	.88	.86	1.08	1.16	1.23	1.23	1.23	1.23	1.23
Net Storage Withdrawals[3]	-.42	-.15	.46	-.02	.00	.00	.00	.00	.00	.00	.00
Total Supply[4]	22.27	19.88	17.37	17.88	17.59	17.49	17.43	17.56	17.55	17.60	16.48
Consumption by Sector[5]											
Residential	4.88	4.90	4.48	4.53	4.51	4.50	4.49	4.49	4.48	4.46	4.17
Commercial[6]	2.60	2.60	2.43	2.76	2.79	2.81	2.82	2.83	2.82	2.81	2.60
Industrial	8.69	6.76	5.58	5.77	5.69	5.69	5.68	5.71	5.65	5.60	5.03
Lease & Plant Fuel[7]	1.50	1.65	.99	.83	.83	.82	.81	.82	.82	.82	.75
Transportation[8]	.73	.53	.56	.90	.90	.89	.89	.90	.90	.90	.84
Electric Utilities	3.66	3.19	2.91	2.98	3.04	2.92	2.88	3.01	3.09	3.19	3.56
Total End-Use Consumption	22.05	19.63	16.95	17.78	17.75	17.63	17.57	17.75	17.76	17.77	16.95
Discrepancy[9]	.22	.25	.42	.10	-.15	-.15	-.14	-.19	-.21	-.17	-.47
Average Wellhead Price	.45	1.31	2.60	2.60	2.68	2.70	2.86	3.06	3.34	3.62	6.33
Delivered Prices by Sectors											
Residential	2.65	3.68	5.95	6.00	6.17	6.32	6.56	6.82	7.18	7.57	10.94
Commercial[6]	1.93	3.21	5.56	5.58	5.70	5.82	6.05	6.30	6.64	7.01	10.30
Industrial	1.01	2.45	4.29	4.29	4.45	4.53	4.74	5.00	5.33	5.70	8.86
Electric Utilities	.78	2.11	3.48	3.49	3.56	3.53	3.69	3.97	4.31	4.65	7.29
Average to all Sectors[10]	1.49	2.85	4.82	4.85	4.98	5.08	5.30	5.55	5.88	6.24	9.31

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.
[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures.
[3] Includes net stock withdrawals for dry natural gas from underground storage, and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.
[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.
[6] Commercial category includes the other customer category.
[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.
[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.
[9] Discrepancy represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definitions, and respondent type.
[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) and Energy Information Administration, *Natural Gas Annual*, 1982 DOE/EIA-0131(82) (Washington, D.C., 1983). Projected values are outputs from the Intermediate Future Forecasting System.
Historical prices thru 1981 and quantities thru 1983.

Table A18. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1983 Dollars per Short Ton)

Supply, Disposition, and Price	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	503	553	578	589	600	612	629	648	727
West of the Mississippi	76	183	282	300	322	337	347	362	380	397	463
Total	599	670	785	853	900	926	947	974	1,010	1,045	1,191
Imports[2]	0	3	1	1	0	0	0	0	0	0	0
Exports[3]	54	41	78	79	83	86	90	94	99	105	116
Net Imports	-54	-38	-77	-78	-83	-86	-90	-94	-99	-105	-116
Net Storage Withdrawals[4]	12	11	28	-5	-6	-5	-4	-5	-6	-7	-8
Total Supply[5]	557	644	736	770	811	835	854	876	905	933	1,067
Consumption by Sector											
Residential and Commercial	11	10	9	8	7	7	7	7	7	7	6
Industrial	68	63	64	67	72	75	78	81	83	85	87
Coking Plants[6]	94	71	37	46	48	49	50	50	51	51	52
Transportation	0	0	0	0	0	0	0	0	0	0	0
Electric Utilities	389	481	626	663	679	699	713	732	758	785	916
Total End-Use Consumption	562	625	735	784	807	831	848	870	899	928	1,061
Discrepancy[7]	-5	19	1	-14	4	5	5	6	6	6	6
Average Minemouth Price[8]	17.58	31.49	28.14	29.30	29.51	29.56	29.78	29.92	30.13	30.36	31.67
Delivered Prices by Sector											
Residential and Commercial[9]	35.24	59.58	46.05	49.97	50.81	51.39	51.91	52.62	53.42	54.18	61.71
Industrial	21.20	43.68	42.54	48.83	48.59	49.65	50.60	51.60	52.71	53.72	62.92
Coking Plants[6]	37.50	74.93	59.74	64.66	64.76	65.39	66.03	66.74	67.51	68.22	74.06
Electric Utilities[10]	20.95	39.49	[11] 36.44	37.57	38.61	38.76	39.06	39.21	39.46	39.88	44.74
Average to All End-Use Sectors[12]	24.03	44.27	38.26	40.26	41.17	41.43	41.81	42.07	42.37	42.81	47.78

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.

[2] Excludes coke imports.

[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.

[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.

[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.

[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents coal used for synthetic fuel production, and errors due to conversion factors.

[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.

[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.

[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.

[11] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated average coal price is $35.17 per short ton.

[12] Weighted average price and the weights are the sectoral consumption values.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation*, (DOE/NBB-0029)/1 (Washington, D.C., 1982) pp. 186-93, Tables B10, B11, B12, and B13. Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981 and quantities thru 1982.

Table A19. National Macroeconomic Indicators

Macroeconomic Indicators	Midprice										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
NIPA Variables[1]											
Real GNP (billion 1983 dollars)	2,714	3,113	3,313	3,472	3,586	3,708	3,840	3,961	4,065	4,169	4,653
Real Disposable Income (billion 1983 dollars)	1,871	2,140	2,371	2,486	2,569	2,651	2,726	2,787	2,847	2,904	3,213
Real Disposable Income Per Capita (thousand 1983 dollars)	8.8	9.6	10.2	10.6	10.8	11.1	11.3	11.4	11.5	11.7	12.4
NIPA GNP Price Deflator (1983=1.00)	.488	.695	1.000	1.043	1.093	1.150	1.211	1.284	1.365	1.452	2.012
GNP Growth (1983 reference year)	NA	NA	.0	4.8	8.2	11.9	15.9	19.6	22.7	25.8	40.4
Unemployment Rate, Civilian Workers (percent)	4.8	6.1	9.8	8.5	8.1	7.8	7.4	7.1	7.0	7.0	7.2
Population, Noninstitutional (million persons)	211.9	222.6	233.3	235.4	237.6	239.9	242.1	244.4	246.6	248.7	258.8
New, High Grade Bond Rate (percent per annum)	7.65	8.88	11.48	11.69	11.54	11.47	11.29	10.99	10.62	10.37	10.14
New Home Mortgage Yields (percent per annum)	8.08	9.69	13.82	14.06	13.99	13.96	13.47	13.02	12.61	12.28	11.31
Total Industrial Production Index (1967=1.00)	1.30	1.46	1.45	1.56	1.64	1.71	1.79	1.87	1.93	1.99	2.26
Total Manufacturing Output Index (1967=1.00)	1.30	1.47	1.46	1.57	1.66	1.73	1.82	1.90	1.97	2.03	2.36
Housing Starts (million units)	2.04	2.00	1.69	1.72	1.68	1.72	1.84	1.83	1.78	1.75	1.47
Energy Usage Indicators											
Gross Energy Use per Capita (million Btu per person)	350.2	350.7	302.1	314.0	316.7	320.2	323.5	325.9	327.2	328.5	332.9
Gross Energy Use per Dollar of GNP (thousand Btu per 1972 dollar)	59.2	54.3	46.0	46.1	45.4	44.8	44.1	43.5	42.9	42.4	40.1
Net Oil Imports (billion 1983 dollars)	14.6	54.7	47.7	47.2	45.0	46.0	51.1	57.9	64.2	72.7	123.8
Net Coal Imports (billion 1983 dollars)	-2.1	-2.8	-4.0	-4.5	-4.6	-4.8	-5.1	-5.5	-6.0	-6.5	-8.4

[1] National Income and Product Accounts.

Appendix B
Low World Oil Price Forecasts

Appendix B
Low World Oil Price Forecasts

The energy projections appearing in this report are highly dependent on the assumed path of future oil prices. In addition to the midprice case projections (Case A), two additional price paths were examined.

The middle world oil forecast (Case A) assumed that the real price of oil (in 1983 dollars) delivered to the United States will decrease from $29.35 in 1983 to $25.56 per barrel in 1986, and then increase to $50.49 by 1995 (see Appendix table A2). In the low world oil price case (Case B) the cost of imported oil is assumed to decline to $22.28 per barrel in 1986 (see Appendix table B2). It subsequently increases to $36.54 per barrel by 1995.

In the low world oil price (Case B) total primary energy consumption is projected be about 4.0 percent higher than in the midprice case in 1995 (see Appendix tables A4 and B4).

The "Guide to Key Tables," and "Location of Key Solution Values," and "Appendix Data Sources," appearing in Appendix A refer to the tables listed in this appendix as well.

Key assumptions for the low world oil price are:

	World Oil Price (1983 Dollars)	Real GNP (Billion 1983 Dollars)	Total Industrial Production Index (1967=1.00)
1983	29.35	3,312	1.46
1984	24.16	3,487	1.57
1985	22.44	3,606	1.65
1986	22.28	3,724	1.72
1987	22.32	3,864	1.80
1988	23.97	3,994	1.89
1989	26.69	4,099	1.95
1990	29.16	4,204	2.02
1991	31.98	4,299	2.07
1992	33.74	4,391	2.12
1993	34.95	4,489	2.18
1994	35.90	4,593	2.25
1995	36.54	4,707	2.32

Table B1. Yearly Supply and Disposition Summary of Total Energy

(Quadrillion Btu per Year)

Total Supply and Disposition	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.3	18.4	18.2	18.0	17.7	17.5	17.6	17.2	15.5
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.3	2.2	2.2	2.3	2.3	2.0
Natural Gas[1]	22.2	19.5	16.3	17.5	16.6	16.2	16.2	16.6	16.7	16.7	14.9
Coal[2]	13.9	14.9	17.3	19.1	20.1	20.6	21.1	21.7	22.4	23.2	26.6
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[3]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.4
Total Production	62.0	61.1	61.0	64.2	64.8	65.1	65.9	67.1	68.4	69.1	69.4
Imports											
Crude Oil[4]	6.9	13.5	7.0	8.6	9.5	10.6	11.8	12.4	12.5	13.1	17.5
Refined Petroleum Products[5]	6.6	4.4	3.5	3.8	3.9	4.1	4.0	4.0	4.0	4.2	5.0
Natural Gas[6]	1.1	1.0	1.1	.9	1.1	1.2	1.3	1.3	1.3	1.3	1.4
Other Imports[7]	.2	.4	.4	.4	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	14.8	16.2	17.4	18.0	18.1	18.9	24.4
Net Stock Withdrawals	-.4	.3	1.0	-.6	-.6	-.6	-.6	-.5	-.5	-.5	-.4
Adjustments[8]	-.1	-.6	.1	.3	.4	.3	.2	.3	.3	.3	.9
Total Supply[9]	76.3	80.0	74.2	77.6	79.4	81.1	83.1	84.9	86.4	87.8	94.3
Disposition											
Exports											
Oil	.5	.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[10]	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.0	31.3	32.2	33.1	33.8	34.3	34.6	34.9	38.7
Natural Gas	22.5	20.0	17.4	18.2	17.9	17.5	17.6	18.0	18.1	18.2	16.8
Coal[12]	12.9	13.7	15.8	17.1	17.7	18.2	18.6	19.0	19.6	20.3	23.3
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.8
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	74.2	78.0	70.5	73.9	75.5	77.2	79.0	80.8	82.1	83.4	89.5
Total Disposition	76.3	80.0	74.2	77.6	79.4	81.1	83.1	84.9	86.4	87.8	94.3

[1] Net dry natural gas: dry marketed production excluding nonhydrocarbon gases.
[2] Historical coal production includes bituminous, anthracite, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other includes geothermal power, wood refuse, and hydropower generated at electric utilities. Hydropower produced by the industrial sector is also included.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes imports of dry natural gas, liquefied natural gas, and supplemental natural gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces.
[9] Total supply is the sum of production, imports, adjustments, and net stock withdrawals.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available

SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System. Historical quantities thru 1983.

Table B2. Yearly Supply and Disposition of Total Energy, Supply Detail

(Quadrillion Btu per Year)

Total Supply	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	8.35	20.69	29.35	24.16	22.44	22.28	22.32	23.97	26.69	29.16	36.54
Domestic Production											
Oil[2]	22.1	20.7	20.5	20.7	20.6	20.3	20.0	19.7	19.9	19.5	17.5
Natural Gas[3]	22.2	19.5	16.3	17.5	16.6	16.2	16.2	16.6	16.7	16.7	14.9
Coal[4]	13.9	14.9	17.3	19.1	20.1	20.6	21.1	21.7	22.4	23.2	26.6
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[5]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.4
Total Domestic Production	62.0	61.1	61.0	64.2	64.8	65.1	65.9	67.1	68.4	69.1	69.4
Imports											
Oil[6]	13.5	17.8	10.6	12.4	13.4	14.7	15.8	16.4	16.5	17.2	22.5
Natural Gas[7]	1.1	1.0	1.1	.9	1.1	1.2	1.3	1.3	1.3	1.3	1.4
Coal[8]	.0	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.3	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	14.8	16.2	17.4	18.0	18.1	18.9	24.4
Net Storage Withdrawals											
Oil	-.3	.5	.5	-.1	-.2	-.2	-.2	-.1	-.1	-.1	-.2
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.5	-.1	-.1	-.1	-.1	-.1	-.1	-.2	-.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	-.4	.3	1.0	-.6	-.6	-.6	-.6	-.5	-.5	-.5	-.4
Available Supply[12]											
Oil	35.3	39.1	31.6	32.9	33.8	34.8	35.6	36.0	36.3	36.6	39.9
Natural Gas	22.8	20.3	17.9	18.4	17.7	17.4	17.4	17.8	17.9	18.0	16.3
Coal	14.2	15.2	17.8	19.0	19.9	20.5	21.0	21.6	22.3	23.1	26.4
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Other Supply[13]	3.1	3.4	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.8
Total Supply (before adjustments)	76.3	80.6	74.1	77.3	79.0	80.8	82.8	84.6	86.0	87.5	93.4
Adjustments[14]	-.1	-.6	.1	.3	.4	.3	.2	.3	.3	.3	.9
Total Supply	76.3	80.0	74.2	77.6	79.4	81.1	83.1	84.9	86.4	87.8	94.3

[1] Average refiners acquisition cost in 1983 dollars per barrel.
[2] Oil includes crude oil, lease condensate, natural gas plant liquids, and other domestic refinery production.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes both dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[NA] = Not available

SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984).
Historical prices thru 1981 and quantities thru 1983.

Table B3. Yearly Supply and Disposition of Total Energy, Disposition Detail
(Quadrillion Btu per Year)

Total Disposition	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[2]	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.7	2.8	2.9	3.0	3.0	3.0	3.0
Natural Gas	7.6	7.6	7.1	7.5	7.5	7.5	7.6	7.6	7.6	7.6	7.1
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	12.3	11.9	9.6	10.2	10.4	10.5	10.6	10.7	10.8	10.8	10.3
Industrial											
Oil[4]	9.1	9.9	7.8	8.6	8.7	8.9	9.1	9.3	9.3	9.4	10.2
Natural Gas[5]	10.4	8.5	6.7	6.7	6.7	6.7	6.7	6.8	6.7	6.7	6.1
Coal[6]	4.0	3.3	2.4	3.0	3.1	3.2	3.3	3.4	3.5	3.5	3.7
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	23.5	21.9	16.9	18.3	18.5	18.8	19.1	19.4	19.6	19.7	20.1
Transportation											
Oil[7]	17.8	20.0	18.4	18.5	19.0	19.4	19.9	20.1	20.3	20.4	21.3
Natural Gas[8]	.7	.5	.6	.9	.9	.9	.9	.9	.9	.9	.8
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	18.5	20.5	19.0	19.5	19.9	20.3	20.8	21.0	21.2	21.3	22.1
Electric Utilities											
Oil	3.5	4.0	1.5	1.6	1.8	2.0	2.0	1.9	2.0	2.1	4.2
Natural Gas	3.7	3.3	3.0	3.1	2.8	2.4	2.4	2.7	2.8	3.0	2.7
Coal	8.7	10.3	13.2	14.0	14.4	14.8	15.1	15.5	16.0	16.5	19.4
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[9]	3.0	3.2	4.0	3.8	3.6	3.6	3.7	3.7	3.7	3.7	3.7
Total Consumption	19.9	23.7	25.0	25.9	26.7	27.6	28.5	29.6	30.6	31.7	37.1
Total Disposition	76.3	80.0	74.2	77.6	79.4	81.1	83.1	84.9	86.4	87.8	94.3

[1] Consists primarily of refined petroleum products.
[2] Consists of coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA 0214(81) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1983.

Table B4. Consumption by Major Fuels and End Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.11	1.23	1.27	1.31	1.35	1.36	1.36	1.35	1.24
Kerosene	.23	.15	.07	.08	.08	.08	.08	.08	.08	.08	.07
Liquefied Petroleum Gas	.59	.52	.29	.25	.26	.26	.27	.27	.27	.27	.24
Natural Gas	4.98	4.98	4.60	4.65	4.65	4.64	4.64	4.65	4.64	4.63	4.37
Steam Coal	.11	.08	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity	1.98	2.30	2.56	2.59	2.65	2.72	2.79	2.87	2.95	3.04	3.45
Total	9.88	9.99	8.71	8.87	8.98	9.08	9.20	9.30	9.38	9.43	9.44
Commercial											
Distillate Fuel	.64	.67	.38	.43	.46	.49	.52	.55	.57	.59	.63
Kerosene	.06	.05	.05	.06	.07	.08	.08	.09	.09	.10	.11
Motor Gasoline	.09	.11	.09	.08	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.29	.38	.41	.44	.47	.49	.52	.53	.57
Liquefied Petroleum Gas	.10	.09	.05	.04	.04	.04	.04	.04	.04	.04	.04
Natural Gas[1]	2.65	2.64	2.49	2.84	2.87	2.90	2.92	2.93	2.94	2.93	2.77
Steam Coal	.15	.13	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity	1.52	1.81	2.12	2.32	2.41	2.50	2.59	2.67	2.75	2.83	3.22
Total	5.89	6.04	5.59	6.27	6.46	6.65	6.82	6.97	7.10	7.21	7.51
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.54	1.59	1.63	1.67	1.71	1.72	1.74	1.92
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Motor Gasoline	.26	.18	.13	.14	.13	.13	.12	.12	.11	.11	.09
Residual Fuel	1.86	1.72	.76	.97	1.03	1.06	1.09	1.09	1.06	1.05	1.14
Liquefied Petroleum Gas	1.26	1.27	1.57	1.34	1.36	1.38	1.40	1.42	1.42	1.42	1.44
Petrochemical Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.22	1.26	1.30	1.32	1.33	1.34	1.47
Other Petroleum[4]	2.33	2.32	1.85	1.96	1.91	1.89	1.90	1.92	1.95	1.99	2.13
Natural Gas[5]	10.39	8.54	6.75	6.74	6.67	6.67	6.71	6.77	6.75	6.69	6.12
Steam Coal	1.54	1.40	1.46	1.70	1.78	1.86	1.94	2.02	2.08	2.13	2.28
Metallurgical Coal	2.45	1.86	.96	1.28	1.31	1.34	1.36	1.39	1.40	1.42	1.47
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Electricity	2.34	2.76	2.65	2.75	2.84	2.95	3.08	3.24	3.38	3.54	4.33
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	25.87	24.62	19.58	21.05	21.34	21.73	22.21	22.67	22.93	23.21	24.39

See footnotes at end of table.

Table B4. Consumption by Major Fuels and End Use Sectors —— Continued
(Quadrillion Btu per Year)

Sector and Fuel	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12
Distillate Fuel	2.22	2.68	2.83	2.66	2.78	2.92	3.08	3.26	3.43	3.60	4.63
Jet Fuel[6]	2.13	2.14	2.13	2.27	2.44	2.58	2.68	2.72	2.74	2.73	2.78
Motor Gasoline	12.46	13.93	12.46	12.60	12.72	12.83	12.94	12.95	12.88	12.78	12.50
Residual Fuel	.73	.99	.73	.65	.68	.70	.73	.75	.76	.78	.85
Liquefied Petroleum Gas	.02	.01	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.15	.28	.30	.31	.33	.34	.35	.36	.40
Natural Gas[7]	.74	.54	.57	.93	.91	.89	.89	.91	.92	.92	.84
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	18.56	20.55	18.97	19.49	19.93	20.35	20.76	21.05	21.20	21.30	22.15
Electric Utilities											
Distillate Fuel	.27	.28	.10	.13	.03	.02	.01	.02	.05	.07	.22
Residual Fuel	3.24	3.71	1.44	1.48	1.72	1.97	1.98	1.92	1.93	2.00	4.03
Natural Gas	3.75	3.30	3.01	3.08	2.76	2.42	2.41	2.70	2.85	3.03	2.71
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.80	15.09	15.47	15.98	16.54	19.38
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.02	3.18	3.95	3.80	3.58	3.64	3.65	3.65	3.68	3.69	3.72
Total	19.85	23.74	24.96	25.92	26.71	27.57	28.53	29.57	30.58	31.66	37.06
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.71	5.98	6.14	6.37	6.64	6.90	7.13	7.36	8.64
Kerosene	.45	.36	.27	.24	.25	.26	.27	.27	.28	.28	.28
Aviation Gasoline	.08	.07	.05	.09	.09	.10	.10	.10	.11	.11	.12
Motor Gasoline	12.80	14.21	12.69	12.82	12.94	13.04	13.14	13.15	13.07	12.97	12.66
Jet Fuel	2.13	2.14	2.13	2.27	2.44	2.58	2.68	2.72	2.74	2.73	2.78
Residual Fuel	6.49	6.95	3.22	3.48	3.83	4.16	4.26	4.25	4.27	4.36	6.59
Liquefied Petroleum Gas	1.98	1.89	1.94	1.64	1.66	1.68	1.71	1.73	1.73	1.73	1.73
Petrochemical Feedstocks	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.22	1.26	1.30	1.32	1.33	1.34	1.47
Lubricants and Waxes	.40	.41	.35	.56	.58	.61	.63	.65	.66	.68	.77
Other Petroleum	2.10	2.09	1.65	1.68	1.62	1.59	1.60	1.62	1.64	1.67	1.76
Natural Gas	22.50	20.00	17.42	18.24	17.86	17.54	17.58	17.97	18.10	18.20	16.80
Steam Coal	10.46	11.87	14.89	15.84	16.38	16.84	17.21	17.65	18.22	18.84	21.81
Metallurgical Coal	2.45	1.86	.96	1.28	1.31	1.34	1.36	1.39	1.40	1.42	1.47
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.06	3.21	3.99	3.83	3.61	3.67	3.69	3.69	3.71	3.72	3.75
Total Consumption	74.20	78.05	70.47	73.92	75.50	77.19	79.04	80.77	82.09	83.38	89.54
Electricity Consumption (all sectors)	5.84	6.89	7.33	7.66	7.92	8.19	8.48	8.79	9.10	9.42	11.01

[1] Commercial natural gas includes the Other category.
[2] Industrial includes all fuels consumed for heat and power, industrial feedstock and raw material uses, all fuels consumed by refineries, and natural gas used as lease and plant fuel.
[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.
[4] Consists of jet fuel, plant condensate, unfractionated stream, miscellaneous, natural gasoline, unfinished oils, special naphthas, asphalt, lubricants, waxes, petroleum coke, aviation blending components, motor gasoline blending components, and road oil.
[5] Includes lease and plant fuel consumption of natural gas.
[6] Jet fuel includes naphtha and kerosene types.
[7] Consists of natural gas used as pipeline compressor fuel.
[8] Other transportation includes steam coal and electricity.
[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA-0214 (82) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1981.

Table B5. Prices by Major Fuels and End Use Sectors
(1983 Dollars per Million Btu)

Sector and Fuel	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.37	5.13	7.88	6.88	6.54	6.50	6.50	6.80	7.33	7.83	9.32
Kerosene	3.85	5.94	8.28	7.23	6.88	6.83	6.83	7.15	7.70	8.22	9.77
Liquefied Petroleum Gas	7.40	6.86	8.80	8.32	8.11	8.11	8.15	8.37	8.69	9.11	10.60
All Petroleum Products	4.25	5.52	8.08	7.13	6.81	6.77	6.77	7.07	7.56	8.05	9.54
Natural Gas	2.60	3.62	5.80	5.85	5.95	6.10	6.24	6.44	6.71	7.11	9.91
Steam Coal[1]	2.39	3.66	2.05	2.10	2.13	2.16	2.18	2.21	2.25	2.28	2.61
Electricity	14.28	17.01	19.02	19.05	19.18	19.42	19.56	19.52	19.36	19.25	19.40
Average[2]	5.41	7.20	10.03	9.90	9.98	10.19	10.36	10.57	10.82	11.16	13.28
Commercial											
Distillate Fuel	2.78	4.53	6.42	5.42	5.08	5.04	5.03	5.34	5.86	6.35	7.83
Kerosene[3]	2.04	4.44	6.35	5.31	4.95	4.91	4.91	5.23	5.77	6.29	7.84
Motor Gasoline[4]	6.34	7.54	9.79	8.48	8.12	8.14	8.19	8.59	9.21	9.72	11.50
Residual Fuel	1.77	3.20	4.97	4.46	4.26	4.27	4.32	4.55	4.86	5.24	6.38
Liquefied Petroleum Gas	3.02	5.07	8.82	8.36	8.16	8.17	8.23	8.45	8.77	9.20	10.69
All Petroleum Products	2.54	4.29	6.44	5.42	5.11	5.07	5.07	5.33	5.75	6.19	7.52
Natural Gas[5]	1.89	3.16	5.42	5.44	5.49	5.62	5.75	5.92	6.18	6.57	9.29
Steam Coal[6]	.90	1.97	2.01	2.06	2.09	2.11	2.14	2.16	2.20	2.23	2.54
Electricity	13.51	16.83	19.20	19.23	19.38	19.65	19.80	19.78	19.60	19.50	19.73
Average[2]	5.03	7.51	10.73	10.48	10.55	10.75	10.91	11.07	11.24	11.51	13.33
Industrial											
Distillate Fuel	1.89	4.04	6.38	5.38	5.04	5.00	4.99	5.30	5.82	6.31	7.79
Kerosene	2.04	4.44	6.81	5.77	5.41	5.37	5.37	5.69	6.24	6.76	8.31
Motor Gasoline[4]	6.34	7.54	9.79	8.46	8.11	8.13	8.18	8.57	9.19	9.70	11.47
Residual Fuel	1.63	3.01	4.12	3.60	3.39	3.41	3.46	3.69	4.01	4.39	5.52
Liquefied Petroleum Gas	2.71	4.44	6.70	6.22	6.02	6.03	6.08	6.31	6.63	7.06	8.57
Petrochemical Feedstocks[7]	1.89	4.04	5.91	4.85	4.49	4.44	4.44	4.77	5.31	5.83	7.39
Still Gas[8]	1.89	4.04	6.29	5.29	4.96	4.92	4.91	5.22	5.74	6.24	7.73
Other Petroleum[9]	2.91	5.07	5.08	4.86	4.74	4.77	4.81	4.99	5.27	5.58	6.68
All Petroleum Products	2.34	4.22	5.92	5.15	4.88	4.87	4.88	5.14	5.57	6.00	7.37
Natural Gas[10]	.99	2.41	4.18	4.17	4.25	4.35	4.46	4.63	4.89	5.28	7.85
Steam Coal	.94	1.97	1.88	1.94	1.98	2.02	2.06	2.10	2.14	2.18	2.54
Metallurgical Coal	1.44	2.88	2.30	2.34	2.38	2.40	2.43	2.45	2.48	2.50	2.72
Net Coke Imports	3.31	7.30	6.52	6.65	6.76	6.82	6.89	6.96	7.04	7.11	7.74
Electricity	7.05	10.94	16.20	16.20	16.32	16.55	16.69	16.63	16.47	16.37	16.48
Average[2]	2.02	4.07	6.18	5.81	5.77	5.86	5.96	6.16	6.44	6.78	8.37

See footnotes at end of table.

Table B5. Prices by Major Fuels and End Use Sectors —— Continued

(1983 Dollars per Million Btu)

Sector and Fuel	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[11]											
Aviation Gasoline	7.70	10.14	12.89	10.90	10.31	10.34	10.42	11.09	12.13	12.99	15.98
Distillate Fuel	3.23	4.76	8.67	7.67	7.33	7.29	7.28	7.59	8.11	8.61	10.09
Jet Fuel[12]	1.98	4.38	6.75	5.66	5.28	5.22	5.23	5.56	6.12	6.64	8.22
Motor Gasoline[13]	6.34	7.54	9.79	8.46	8.10	8.12	8.17	8.57	9.18	9.69	11.46
Residual Fuel[14]	1.31	2.17	3.36	2.84	2.64	2.66	2.71	2.94	3.26	3.64	4.79
Liquefied Petroleum Gas[15]	2.71	4.44	8.13	7.66	7.46	7.47	7.53	7.75	8.07	8.49	9.98
Lubricants and Waxes[16]	12.10	14.42	22.68	20.98	20.39	20.32	20.32	20.85	21.73	22.59	25.13
All Petroleum Products	5.28	6.63	9.13	8.01	7.64	7.62	7.65	8.01	8.59	9.10	10.75
Natural Gas[17]	.50	1.27	2.53	2.53	2.56	2.61	2.64	2.77	2.98	3.32	5.51
Electricity	13.17	16.55	18.47	18.45	18.63	18.91	19.04	19.02	18.83	18.72	18.97
Average[2]	5.09	6.50	8.93	7.75	7.41	7.41	7.44	7.79	8.36	8.86	10.56
Electric Utilities											
Distillate Fuel[18]	2.19	3.89	6.94	5.70	5.40	5.42	5.29	5.62	6.16	6.58	7.94
Residual Fuel	1.59	3.05	4.28	3.75	3.69	3.71	3.79	4.07	4.41	4.76	5.85
All Petroleum Products	1.64	3.11	4.46	3.91	3.73	3.73	3.79	4.09	4.45	4.82	5.96
Natural Gas	.76	2.04	3.37	3.32	3.19	3.23	3.28	3.44	3.71	4.11	5.99
Steam Coal	.94	1.85	[19] 1.72	1.78	1.82	1.83	1.85	1.86	1.88	1.90	2.14
Fossil Fuel Average	1.05	2.17	2.24	2.22	2.19	2.21	2.22	2.29	2.38	2.49	3.15
Average Price to All Users											
Distillate Fuel	2.88	4.63	7.82	6.72	6.39	6.36	6.36	6.68	7.21	7.72	9.25
Kerosene	2.96	5.07	7.11	6.10	5.74	5.69	5.67	5.98	6.51	7.02	8.52
Aviation Gasoline	7.70	10.14	12.89	10.90	10.31	10.34	10.42	11.09	12.13	12.99	15.98
Motor Gasoline	6.34	7.54	9.79	8.46	8.10	8.12	8.17	8.57	9.18	9.69	11.46
Jet Fuel	1.98	4.38	6.75	5.66	5.28	5.22	5.23	5.56	6.12	6.64	8.22
Residual Fuel	1.59	2.93	4.10	3.62	3.49	3.52	3.58	3.83	4.16	4.53	5.71
Liquefied Petroleum Gas	2.71	4.44	6.70	6.22	6.02	6.03	6.08	6.31	6.63	7.06	8.57
Petrochemical Feedstocks	1.89	4.04	5.91	4.85	4.49	4.44	4.44	4.77	5.31	5.83	7.39
Lubricants and Waxes	12.10	14.42	22.68	20.98	20.39	20.32	20.32	20.85	21.73	22.59	25.13
Other Petroleum Products	1.89	4.04	5.41	4.45	4.11	4.06	4.06	4.34	4.81	5.28	6.66
All Petroleum Products	3.88	5.41	7.86	6.80	6.46	6.43	6.45	6.78	7.29	7.75	9.05
Natural Gas	1.39	2.71	4.58	4.56	4.63	4.77	4.88	5.03	5.27	5.65	8.20
Coal	1.05	2.02	1.78	1.84	1.88	1.90	1.92	1.93	1.95	1.98	2.22
Electricity	11.18	14.53	18.05	18.08	18.21	18.45	18.59	18.54	18.36	18.24	18.35
Average	3.20	4.91	6.72	6.25	6.17	6.25	6.33	6.51	6.78	7.06	8.26

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer mark-up.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Historical price for commercial kerosene is the price of industrial kerosene.
[4] Historical price for commercial and for industrial motor gasoline is the price of transportation motor gasoline.
[5] Commercial natural gas price is a weighted average of the commercial and other category.
[6] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer mark-up, where applicable.
[7] Industrial distillate price is used in historical years (through 1981).
[8] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[9] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[10] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[11] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[12] Jet fuel price is for kerosene type jet fuel at retail.
[13] Gasoline price is an average for all types.
[14] Residual fuel price is for marine bunker.
[15] Historical price for transportation LPG is the price of industrial LPG.
[16] Historical price is the price of industrial lubricants.
[17] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[18] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.
[19] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated actual average coal price is $1.66 per million Btu.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1*, (DOE/NBB-0029)/1 (Washington, D.C., 1982), pp. 229-95, Tables, C1 through C29. Projected prices are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981.

Table B6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	Low Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Total Fuel Use									
Space Heating	4.51	4.63	4.69	4.75	4.81	4.84	4.85	4.83	4.52
Water Heating	1.65	1.64	1.65	1.66	1.68	1.69	1.71	1.72	1.78
Air Conditioning	.37	.38	.39	.40	.41	.42	.44	.45	.50
Other End Uses[2]	2.17	2.21	2.23	2.26	2.30	2.34	2.38	2.42	2.63
Total	8.71	8.87	8.97	9.08	9.19	9.30	9.37	9.42	9.44
Liquefied Petroleum Gas									
Space Heating	.21	.18	.18	.19	.19	.19	.19	.19	.16
Water Heating	.09	.07	.07	.08	.08	.08	.08	.08	.08
Total	.29	.25	.26	.26	.27	.27	.27	.27	.24
Fuel Oil[3]									
Space Heating	.96	1.07	1.11	1.15	1.19	1.21	1.21	1.20	1.07
Water Heating	.22	.24	.24	.24	.23	.23	.23	.23	.23
Total	1.18	1.30	1.35	1.39	1.43	1.44	1.44	1.43	1.31
Natural Gas									
Space Heating	3.03	3.07	3.06	3.06	3.06	3.06	3.05	3.03	2.76
Water Heating	1.01	1.02	1.02	1.02	1.02	1.03	1.03	1.03	1.04
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.01	.01
Other End Uses[2]	.54	.55	.55	.55	.55	.55	.55	.55	.56
Total	4.60	4.65	4.65	4.64	4.64	4.65	4.64	4.63	4.37
Coal									
Space Heating	.08	.07	.07	.07	.06	.06	.06	.06	.05
Total	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity									
Space Heating	.23	.25	.27	.28	.30	.32	.34	.36	.47
Water Heating	.33	.31	.32	.33	.34	.35	.36	.37	.42
Air Conditioning	.36	.37	.38	.39	.40	.41	.42	.43	.49
Other End Uses[2]	1.64	1.65	1.68	1.72	1.75	1.79	1.83	1.87	2.08
Total	2.56	2.59	2.65	2.72	2.79	2.87	2.95	3.04	3.45
Non-Marketed Fuel Consumption[1]									
Wood	0.89	0.92	0.94	0.95	0.96	0.97	0.98	0.99	1.06
Residential Activity									
Occupied Housing Stock (million units)	85.0	86.5	88.1	89.6	91.2	92.9	94.6	96.3	104.2
New Housing Construction[4] (million units)	1.5	2.0	2.0	2.0	2.1	2.2	2.2	2.1	1.9
Income Per Household (thousand 1983 dollars)	21.1	21.7	22.1	22.4	22.6	22.8	22.9	23.0	23.7
Energy Use Per Household (million Btu)	103	102	102	101	101	100	99	98	91
Fuel Expenditure Per Household (1983 dollars)	1,026	1,012	1,015	1,030	1,042	1,055	1,070	1,090	1,201

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multi-family, and mobile housing units.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration, DOE/EIA-0409, July 1983. The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.

Table B7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	Low Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	5.60	6.26	6.46	6.65	6.82	6.96	7.10	7.21	7.51
Liquefied Petroleum Gas	.05	.04	.04	.04	.04	.04	.04	.04	.04
Motor Gasoline	.09	.08	.08	.08	.08	.08	.08	.08	.08
Fuel Oil[1]									
Office[2]	.25	.29	.32	.34	.36	.37	.39	.40	.43
Retail/Wholesale	.16	.19	.20	.22	.23	.25	.25	.26	.27
Warehouse	.12	.14	.16	.18	.19	.21	.22	.23	.27
Other Buildings[3]	.20	.24	.26	.27	.29	.31	.32	.33	.34
Total	.73	.87	.94	1.01	1.07	1.13	1.18	1.22	1.31
Natural Gas									
Office[2]	.70	.80	.81	.82	.82	.83	.83	.83	.78
Retail/Wholesale	.70	.82	.84	.85	.86	.87	.88	.88	.87
Warehouse	.37	.39	.39	.40	.40	.40	.40	.40	.37
Other Buildings[3]	.72	.83	.83	.84	.84	.84	.83	.82	.74
Total	2.49	2.84	2.87	2.90	2.92	2.93	2.94	2.93	2.77
Coal	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity									
Office[2]	.81	.88	.92	.95	.99	1.02	1.05	1.08	1.23
Retail/Wholesale	.59	.67	.70	.73	.76	.78	.81	.83	.95
Warehouse	.30	.31	.33	.34	.35	.36	.38	.39	.44
Other Buildings[3]	.42	.45	.47	.48	.49	.51	.52	.53	.59
Total	2.12	2.32	2.41	2.50	2.59	2.67	2.75	2.83	3.22
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.7	50.7	52.4	54.0	55.5	56.9	58.3	59.6	66.4
Office[2]	17.1	17.8	18.4	19.0	19.6	20.1	20.5	21.0	23.5
Retail/Wholesale	14.5	15.3	15.8	16.4	16.9	17.4	17.9	18.3	20.7
Warehouse	6.9	7.2	7.5	7.7	7.9	8.1	8.4	8.6	9.6
Other Buildings[3]	10.1	10.4	10.7	10.9	11.1	11.3	11.5	11.7	12.7
Energy Use Per Square Foot (thousand Btu)	115.1	123.5	123.3	123.1	122.9	122.4	121.8	120.8	113.1
Expenditures Per Square Foot (1983 dollars)	1.20	1.27	1.28	1.30	1.32	1.33	1.35	1.37	1.48

[1] The commercial fuel oil category includes kerosene, distillate oil, and residual oil.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
SOURCE: The Commercial model is documented in *A Model of Commercial Energy Use Based Macroeconomic Data*, Brookhaven National Laboratory, April 1983. The major model source is the public use tape of the Non-Residential Energy Consumption Survey 1980, Energy Information Administration.

Table B8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.53	1.58	1.62	1.66	1.70	1.71	1.73	1.91
Residual Fuel	1.58	1.40	.65	.85	.91	.94	.96	.96	.94	.93	1.00
Liquefied Petroleum Gas	.11	.16	.64	.33	.34	.34	.35	.35	.35	.35	.38
Natural Gas	8.50	7.08	5.56	5.49	5.41	5.39	5.40	5.44	5.41	5.36	4.74
Steam Coal[1]	1.54	1.40	1.46	1.70	1.78	1.86	1.94	2.02	2.08	2.13	2.28
Electricity[2]	2.34	2.76	2.54	2.64	2.73	2.84	2.96	3.12	3.26	3.42	4.19
Total	15.51	14.51	12.14	12.55	12.75	12.98	13.27	13.57	13.74	13.93	14.50
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.11	.11	.12	.13	.13	.13	.13	.12	.14
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.04
Still Gas	1.07	1.29	1.12	1.20	1.22	1.26	1.30	1.32	1.33	1.34	1.47
Petroleum Coke	.40	.39	.30	.30	.30	.31	.32	.33	.33	.33	.36
Other Petroleum	.00	.00	.01	.01	.01	.01	.01	.01	.01	.01	.01
Electricity	NA	NA	.11	.11	.11	.11	.12	.12	.12	.12	.13
Natural Gas	1.11	.82	.69	.69	.70	.72	.75	.76	.77	.78	.85
Total	2.93	2.93	2.37	2.46	2.51	2.59	2.67	2.72	2.73	2.74	3.03
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.13	.14	.13	.13	.12	.12	.11	.11	.09
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Petroleum Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Liquefied Petroleum Gas[4]	1.11	1.05	.90	.98	.99	1.00	1.02	1.03	1.03	1.03	1.03
Special Naphthas	.17	.20	.15	.24	.26	.27	.28	.29	.29	.30	.33
Lubricants and Waxes	.23	.23	.20	.28	.29	.29	.30	.31	.32	.32	.37
Petroleum Coke	.16	.16	.16	.27	.29	.30	.30	.30	.29	.28	.28
Asphalt and Road Oil	1.26	1.16	.90	1.08	1.11	1.11	1.13	1.14	1.14	1.13	1.05
Other Raw Materials[5]	.11	.18	.13	-.23	-.34	-.41	-.45	-.45	-.42	-.38	-.27
Metallurgical Coal[1]	2.45	1.86	.96	1.28	1.31	1.34	1.36	1.39	1.40	1.42	1.47
Natural Gas Raw Materials[6]	.78	.63	.49	.55	.56	.56	.57	.57	.57	.56	.52
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03	-.04
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	7.43	7.18	5.07	6.04	6.08	6.15	6.26	6.38	6.46	6.54	6.87
Total Industrial Demand	25.87	24.62	19.58	21.05	21.34	21.73	22.21	22.67	22.93	23.21	24.39

[1] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[2] Includes refinery electricity before 1980.
[3] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[4] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[5] Other products includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components.
[6] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, D.C., 1984)
Historical quantities thru 1981.

Table B9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	Low Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.09	0.09	0.10	0.10	0.10	0.11	0.11	0.12
Distillate Fuel	2.83	2.66	2.78	2.92	3.08	3.26	3.43	3.60	4.63
Jet Fuel	2.13	2.27	2.44	2.58	2.68	2.72	2.74	2.73	2.78
Motor Gasoline	12.46	12.60	12.72	12.83	12.94	12.95	12.88	12.78	12.50
Residual Fuel	.73	.65	.68	.70	.73	.75	.76	.78	.85
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.15	.28	.30	.31	.33	.34	.35	.36	.40
Natural Gas	.57	.93	.91	.89	.89	.91	.92	.92	.84
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	18.97	19.49	19.93	20.35	20.76	21.05	21.20	21.30	22.15
Automobiles									
Vehicle-Miles Travelled[2]	1,155.1	1,253.7	1,361.8	1,463.4	1,558.0	1,632.7	1,688.8	1,735.8	1,960.2
Fleet-Miles per Gallon	16.5	17.5	18.6	19.7	20.7	21.6	22.6	23.4	27.0
Total Fuel Use[3]	69.9	71.8	73.3	74.5	75.4	75.5	74.9	74.1	72.5
Trucks									
Vehicle-Miles Travelled[2]	451.7	475.5	504.7	537.0	573.3	612.6	653.2	695.1	923.0
Fleet-Miles per Gallon	10.5	11.0	11.6	12.1	12.7	13.2	13.7	14.3	16.7
Total Fuel Use[3]	42.9	43.2	43.5	44.2	45.2	46.4	47.5	48.7	55.2
Air									
Revenue Passenger Miles[2]	290.6	326.2	371.4	412.2	447.2	473.0	492.2	507.2	602.2
Fuel Burned Per Seat Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	15.9	17.0	18.3	19.3	20.0	20.4	20.5	20.5	20.8
Aviation Gasoline[3]	.4	.7	.8	.8	.8	.9	.9	.9	1.0
Selected Fuel Expenditures[5]									
Motor Gasoline	122.1	106.5	103.1	104.2	105.7	111.0	118.2	123.8	143.2
Distillate Fuel	24.5	20.4	20.4	21.3	22.5	24.7	27.8	31.0	46.8

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1983 Dollars per Year.

Table B10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.13	0.03	0.02	0.01	0.02	0.05	0.07	0.22
Residual LS[1]	NA	NA	.81	.87	1.23	1.43	1.45	1.42	1.42	1.46	2.90
Residual HS[1]	3.24	3.71	.63	.61	.49	.54	.52	.50	.50	.54	1.13
Natural Gas	3.75	3.30	3.01	3.08	2.76	2.42	2.41	2.70	2.85	3.03	2.71
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.80	15.09	15.47	15.98	16.54	19.38
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[2]	2.87	2.97	3.61	3.48	3.25	3.29	3.30	3.29	3.30	3.30	3.32
Total Fuel Inputs	19.70	23.53	24.61	25.60	26.38	27.23	28.18	29.21	30.21	31.27	36.67
Net Imports	.15	.20	.35	.32	.33	.34	.35	.36	.37	.39	.40
Total Electricity Inputs	19.85	23.74	24.96	25.92	26.71	27.57	28.53	29.57	30.58	31.66	37.06
Disposition											
Total Electricity Inputs	19.85	23.74	24.96	25.92	26.71	27.57	28.53	29.57	30.58	31.66	37.06
Minus Conversion Losses[3]	13.50	16.21	17.08	17.61	18.14	18.72	19.37	20.08	20.77	21.51	25.19
Equals Generation	6.35	7.53	7.88	8.30	8.57	8.85	9.16	9.49	9.81	10.15	11.87
Minus Transportation and Distribution Losses	.51	.64	.55	.64	.65	.66	.68	.70	.71	.73	.87
Equals Electricity Sales	5.84	6.89	7.33	7.66	7.92	8.19	8.48	8.79	9.10	9.42	11.01
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.59	2.65	2.72	2.79	2.87	2.95	3.04	3.45
Commercial/Other[4]	1.53	1.82	2.13	2.33	2.42	2.52	2.60	2.68	2.76	2.84	3.23
Industrial	2.34	2.76	2.65	2.75	2.84	2.95	3.08	3.24	3.38	3.54	4.33
Total Electricity Sales	5.84	6.89	7.33	7.66	7.92	8.19	8.48	8.79	9.10	9.42	11.01

[1] Prior to 1983, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available
SOURCE: Historical quantities thru 1983.

Table B11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1983 Dollars per Thousand Kilowatthours)

Prices and Demands	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	48.7	58.0	64.9	65.0	65.4	66.3	66.8	66.6	66.1	65.7	66.2
Commercial[2]	46.1	57.4	65.5	65.6	66.1	67.1	67.6	67.5	66.9	66.5	67.3
Industrial	24.1	37.3	55.3	55.3	55.7	56.5	56.9	56.7	56.2	55.8	56.2
All Sectors	38.1	49.6	61.7	61.7	62.2	63.0	63.4	63.3	62.6	62.2	62.6
Demands											
Residential	579	674	749	758	777	797	818	842	866	891	1,012
Commercial[2]	447	534	624	682	711	737	763	786	809	832	946
Industrial	686	809	776	806	832	865	903	949	991	1,039	1,268
All Sectors	1,713	2,018	2,149	2,246	2,320	2,400	2,484	2,576	2,667	2,762	3,226

[1] Prices for 1983-95 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price System, Volume 1*, DOE/NBB-0029/1, (Washington, D.C., 1982). Demands for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984).

Table B12. Electric Utility Capacity and Generation
(Generation in Billion Kilowatthours per Year)
(Capacity in Million Kilowatts)

Capacity and Generation	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	320.6	399.5	454.1	297.7	305.6	312.2	317.8	324.3	329.7	335.5	364.8
Natural Gas Steam	-	-	-	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Oil Steam	-	-	-	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
Natural Gas/Oil Steam	-	-	-	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8
Natural Gas Combined Cycle	-	-	-	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Oil Combined Cycle	-	-	-	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Natural Gas Turbine	38.4	54.5	56.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil Turbine	-	-	-	24.5	24.5	24.5	24.5	24.5	24.6	24.7	24.8
Natural Gas/Oil Turbine	-	-	-	24.7	24.7	24.8	24.8	24.9	25.2	25.5	39.1
Nuclear Power	21.0	53.5	66.0	73.6	84.8	94.3	104.3	104.8	107.1	110.8	119.1
Hydropower/Other[2]	62.4	71.6	80.3	69.9	71.3	72.0	72.1	72.5	72.5	72.6	72.7
Pumped Storage Hydropower[3]	-	-	-	14.3	15.3	16.4	18.3	18.8	18.8	18.8	18.9
Total Capacity	442.4	579.2	657.0	678.4	700.0	717.9	735.5	743.5	751.7	761.5	813.4
Generation by Plant Type[1]											
Coal Steam	1,467	1,610	1,662	1,350	1,398	1,436	1,466	1,503	1,554	1,609	1,890
Natural Gas Steam	-	-	-	54	56	59	62	65	68	69	52
Oil Steam	-	-	-	95	104	108	108	116	118	123	152
Natural Gas/Oil Steam	-	-	-	231	215	204	201	209	216	230	323
Natural Gas Combined Cycle	-	-	-	33	29	28	27	29	29	30	27
Oil Combined Cycle	-	-	-	1	1	0	0	1	1	1	1
Natural Gas Turbine	37	36	16	1	1	1	1	1	2	2	3
Oil Turbine	-	-	-	8	2	2	1	1	3	4	15
Natural Gas/Oil Turbine	-	-	-	6	8	6	6	8	9	11	54
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
Hydropower/Other[2]	274	283	338	342	320	326	328	328	330	330	330
Pumped Storage Hydropower[3]	-	-	-	-7	-7	-9	-11	-12	-12	-12	-11
Total Generation	1,861	2,206	2,309	2,433	2,511	2,594	2,684	2,781	2,876	2,976	3,480
Generation by Fuel Type											
Coal[4]	848	976	1,259	1,344	1,391	1,429	1,459	1,496	1,547	1,603	1,883
Natural Gas	341	305	274	284	254	225	223	250	263	278	234
Oil	314	365	145	152	167	190	190	186	188	196	400
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
All Hydropower/Other[5]	274	283	338	335	312	317	318	317	318	318	319
Total Generation	1,861	2,206	2,309	2,433	2,511	2,594	2,684	2,781	2,876	2,976	3,480

[1] Historical data for 1973, 1978, and 1983 are given by prime mover only. Thus for the historical period, all steam and combined cycle capacity and generation is shown in the coal steam category; all turbine and internal combustion capacity and generation are shown in the natural gas turbine category; and all conventional hydroelectric, pumped storage hydroelectric, and other renewable capacity and generation is shown in the hydropower/other category.

[2] This category includes other renewable sources such as geothermal, wood, waste, solar, and wind.

[3] See Appendix E, electricity terminology for definition of pumped storage plant.

[4] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[5] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal, wood, waste, solar, and wind.

- See footnote 1.

SOURCE: Data for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984). Capacity data for projection years 1984-95 are based on the Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table B13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	Low Price												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	5,922	5,264	5,820
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	1,813	3,080	3,228	3,648	2,092
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total New Capacity	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	10,441	13,130	11,447	8,912	7,912
Pipeline[6]													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	3,915	1,450	400
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	361	71	0	0	50
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total Pipeline	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	8,989	10,120	6,212	1,450	450
New Starts[7]													
Nuclear Power	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	2,007	3,814	5,420
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	1,452	3,009	3,228	3,648	2,042
Pumped Storage Hydro[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	0	0	0	0	0	0	0	0	1,452	3,009	5,235	7,462	7,462

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam capacity
[3] Includes all gas turbine and internal combustion capacity
[4] See Appendix E, electricity terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.

SOURCE: The Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table B14. Summary of Components of Electricity Price
(1983 Dollars per Thousand Kilowatthours)

Price Components	Low Price												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	24.5	24.6	25.2	25.9	26.4	25.9	24.8	23.5	22.6	21.6	20.6	19.7	18.8
Fuel Component[2]	22.2	22.1	21.7	21.6	21.5	21.9	22.6	23.6	24.8	25.8	27.1	28.3	29.4
O&M Component[3]	14.9	15.0	15.3	15.5	15.5	15.4	15.3	15.1	15.0	14.9	14.8	14.6	14.5
Total Price[4]	61.7	61.7	62.2	63.0	63.4	63.3	62.6	62.2	62.3	62.4	62.5	62.7	62.6

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.

Table B15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.65	8.65	8.57	8.46	8.33	8.21	8.24	8.04	6.97
Alaska North Slope	.00	1.09	1.64	1.65	1.71	1.79	1.78	1.78	1.77	1.67	1.23
Subarctic	9.21	7.62	7.02	7.00	6.86	6.67	6.55	6.43	6.47	6.37	5.74
Natural Gas Plant Liquids	1.74	1.57	1.56	1.58	1.64	1.60	1.55	1.55	1.59	1.60	1.43
Other Domestic[2]	.01	.01	.05	.05	.05	.05	.05	.06	.07	.09	.34
Processing Gain[3]	.45	.50	.48	.51	.50	.52	.53	.54	.54	.54	.60
Total Production	11.40	10.78	10.74	10.80	10.76	10.63	10.46	10.36	10.44	10.27	9.34
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.30	4.05	4.50	4.99	5.56	5.86	5.89	6.16	8.27
Refined Products	3.01	2.01	1.69	1.81	1.84	1.94	1.92	1.90	1.89	1.98	2.38
Total Imports	6.26	8.36	4.99	5.86	6.34	6.93	7.48	7.76	7.78	8.14	10.65
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.57	.54	.61	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.72	.78	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	6.02	8.00	4.25	5.14	5.56	6.15	6.70	6.98	7.00	7.36	9.87
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.26	-.06	-.08	-.08	-.08	-.06	-.03	-.03	-.09
SPR Fill Rate Additions (-) [6]	.00	-.16	-.23	-.17	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	17.29	18.87	15.02	15.71	16.10	16.54	16.93	17.13	17.26	17.45	19.11
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.70	6.75	6.79	6.85	6.86	6.82	6.76	6.60
Aviation Gasoline	.05	.04	.03	.05	.05	.05	.05	.06	.06	.06	.07
Jet Fuel[8]	1.06	1.06	1.04	1.11	1.19	1.26	1.31	1.33	1.34	1.34	1.36
Kerosene	.22	.18	.13	.12	.12	.13	.13	.13	.13	.14	.13
Distillate Fuel	3.09	3.43	2.68	2.80	2.88	3.00	3.12	3.24	3.35	3.46	4.06
Residual Fuel	2.82	3.02	1.40	1.51	1.67	1.81	1.86	1.85	1.86	1.90	2.87
Liquid Petroleum Gas	1.45	1.41	1.47	1.23	1.25	1.27	1.29	1.30	1.30	1.30	1.30
Petrochemical Feedstocks	.36	.59	.41	.64	.67	.70	.74	.77	.79	.82	.94
Other Petroleum Products[9]	1.59	1.70	1.37	1.53	1.53	1.55	1.57	1.60	1.62	1.65	1.80
Total Product Supplied	17.31	18.85	15.15	15.70	16.12	16.55	16.92	17.15	17.27	17.41	19.14
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.28	1.33	1.39	1.44	1.47	1.50	1.50	1.47
Industrial[10]	4.49	4.89	4.01	4.33	4.41	4.49	4.59	4.67	4.70	4.75	5.13
Transportation	9.03	10.13	9.31	9.39	9.62	9.83	10.03	10.16	10.22	10.26	10.68
Electric Utilities	1.54	1.75	.67	.71	.76	.87	.87	.85	.86	.90	1.86
Total End-Use Consumption	17.30	18.84	15.19	15.70	16.12	16.57	16.93	17.15	17.28	17.42	19.14
Discrepancy[11]	-.01	.03	-.17	.01	-.03	-.03	.00	-.02	-.02	.03	-.03
Net Disposition[12]	17.29	18.87	15.02	15.71	16.10	16.54	16.93	17.13	17.26	17.45	19.11

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.
NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.
SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1983.

Table B16. Petroleum Product Prices
(1983 Dollars per Barrel)

Sector and Fuel	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	8.35	20.69	29.35	24.16	22.44	22.28	22.32	23.97	26.69	29.16	36.54
Refinery Acquisition Cost[2]	8.50	17.93	29.35	24.16	22.44	22.28	22.32	23.97	26.69	29.16	36.54
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	18.78	28.99	43.75	37.90	35.85	35.54	35.45	37.18	40.14	42.97	51.36
Kerosene	19.55	31.42	42.33	35.96	33.80	33.41	33.24	34.92	37.85	40.65	48.94
Motor Gasoline[3]	33.32	39.58	51.45	44.53	42.68	42.78	43.05	45.15	48.38	51.06	60.39
Residual Fuel	11.15	20.10	31.27	28.02	26.75	26.87	27.18	28.59	30.58	32.94	40.14
Liquefied Petroleum Gas[4]	25.27	24.17	32.05	30.34	29.56	29.57	29.74	30.53	31.69	33.23	38.65
Average[5]	19.62	27.34	40.13	35.45	33.69	33.48	33.47	34.99	37.49	40.03	47.73
Industrial											
Distillate Fuel	10.99	23.54	37.18	31.36	29.36	29.11	29.08	30.87	33.88	36.77	45.39
Kerosene	11.56	25.19	38.61	32.71	30.70	30.47	30.45	32.28	35.36	38.31	47.12
Motor Gasoline[3]	33.32	39.58	51.45	44.44	42.59	42.69	42.95	45.04	48.27	50.95	60.25
Residual Fuel	10.25	18.90	25.93	22.65	21.34	21.45	21.77	23.20	25.23	27.62	34.73
Liquefied Petroleum Gas	10.14	16.30	24.39	22.66	21.92	21.95	22.15	22.98	24.16	25.73	31.22
Petrochemical Feedstocks[6]	10.54	22.80	33.29	27.20	25.17	24.88	24.89	26.72	29.78	32.71	41.45
Asphalt & Road Oil	12.51	26.82	24.67	22.81	22.10	22.17	22.36	23.17	24.32	25.68	29.81
Petroleum Coke	11.36	24.35	7.43	7.24	7.16	7.17	7.19	7.29	7.43	7.59	8.10
Special Naphthas	9.90	21.21	32.95	27.71	25.93	25.72	25.71	27.33	30.06	32.68	40.49
Miscellaneous Petroleum Products	11.78	25.03	32.51	26.76	24.73	24.43	24.42	26.10	28.91	31.71	40.00
Average[5]	11.58	21.75	28.15	24.74	23.42	23.33	23.44	24.71	26.73	28.89	35.74
Transportation[7]											
Distillate Fuel	18.80	27.70	50.47	44.66	42.67	42.44	42.42	44.21	47.24	50.14	58.80
Aviation Gasoline	38.87	51.21	65.05	55.05	52.03	52.19	52.60	56.00	61.25	65.59	80.69
Motor Gasoline[3]	33.33	39.58	51.45	44.42	42.56	42.66	42.92	45.00	48.23	50.90	60.18
Jet Fuel[8]	11.11	24.59	37.88	31.73	29.63	29.25	29.31	31.19	34.30	37.25	46.10
Residual Fuel[9]	8.21	13.67	21.13	17.87	16.61	16.73	17.06	18.47	20.48	22.85	30.10
Liquefied Petroleum Gas	10.14	16.30	29.60	27.92	27.18	27.23	27.43	28.24	29.40	30.94	36.37
Lubricants[10]	73.36	87.47	137.58	127.22	123.69	123.27	123.23	126.43	131.81	136.99	152.40
Average[5]	28.52	35.87	49.39	43.33	41.35	41.30	41.48	43.50	46.70	49.50	58.75
Electric Utilities											
Distillate Fuel	12.73	22.69	40.43	33.19	31.44	31.55	30.79	32.71	35.86	38.33	46.25
Residual Fuel	9.99	19.17	26.93	23.61	23.23	23.33	23.80	25.61	27.73	29.93	36.80
Average[5]	10.22	19.43	27.87	24.41	23.39	23.43	23.85	25.71	27.94	30.23	37.32
Refined Petroleum Product Prices											
Distillate Fuel	16.80	26.98	45.53	39.12	37.24	37.05	37.07	38.92	42.01	44.97	53.89
Kerosene	16.77	28.75	40.33	34.59	32.52	32.24	32.16	33.92	36.92	39.80	48.33
Aviation Gasoline	38.87	51.21	65.05	55.05	52.03	52.19	52.60	56.00	61.25	65.59	80.69
Motor Gasoline[3]	33.33	39.58	51.45	44.42	42.57	42.66	42.92	45.01	48.23	50.90	60.18
Jet Fuel[8]	11.11	24.59	37.88	31.73	29.63	29.25	29.31	31.19	34.30	37.25	46.10
Residual Fuel	9.98	18.39	25.76	22.75	21.93	22.12	22.50	24.09	26.15	28.48	35.87
Liquefied Petroleum Gas	15.49	18.83	25.83	24.05	23.30	23.33	23.52	24.34	25.52	27.07	32.44
Lubricants (Transportation)[10]	73.36	87.47	137.58	127.22	123.69	123.27	123.23	126.43	131.81	136.99	152.40
Petrochemical Feedstocks[6]	10.54	22.80	33.29	27.20	25.17	24.88	24.89	26.72	29.78	32.71	41.45
Asphalt & Road Oil	12.51	26.82	24.67	22.81	22.10	22.17	22.36	23.17	24.32	25.68	29.81
Petroleum Coke	11.36	24.35	7.43	7.24	7.16	7.17	7.19	7.29	7.43	7.59	8.10
Special Naphthas	9.90	21.21	32.95	27.71	25.93	25.72	25.71	27.33	30.06	32.68	40.49
Miscellaneous Petroleum Products	11.78	25.03	32.51	26.76	24.73	24.43	24.42	26.10	28.91	31.71	40.00

[1] Average cost of crude oil imported into the United States.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation* DOE/NBB-029)/1 (Washington, D. C., 1982) pp. 194-225, Tables B14 Through B29. Projected values are output from the Intermediate Future Forecasting System.

Historical prices thru 1981.

Table B17. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)
(1983 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.90	17.03	16.17	15.74	15.74	16.11	16.24	16.28	14.49
Supplemental Natural Gas[2]	.00	.00	.13	.01	.00	.06	.01	.00	.00	.04	.16
Net Imports	.96	.91	.88	.86	1.08	1.16	1.23	1.23	1.23	1.23	1.23
Net Storage Withdrawals[3]	-.42	-.15	.46	-.02	.00	.00	.00	.00	.00	.00	.00
Total Supply[4]	22.27	19.88	17.37	17.88	17.25	16.95	16.98	17.34	17.47	17.55	15.88
Consumption by Sector[5]											
Residential	4.88	4.90	4.48	4.54	4.53	4.53	4.53	4.53	4.53	4.51	4.26
Commercial[6]	2.60	2.60	2.43	2.77	2.80	2.83	2.85	2.86	2.86	2.86	2.70
Industrial	8.69	6.76	5.58	5.73	5.69	5.72	5.75	5.79	5.76	5.71	5.24
Lease & Plant Fuel[7]	1.50	1.65	.99	.84	.81	.79	.79	.81	.81	.82	.73
Transportation[8]	.73	.53	.56	.90	.88	.87	.87	.89	.89	.90	.81
Electric Utilities	3.66	3.19	2.91	2.98	2.67	2.34	2.33	2.61	2.75	2.92	2.62
Total End-Use Consumption	22.05	19.63	16.95	17.75	17.38	17.07	17.11	17.49	17.61	17.71	16.35
Discrepancy[9]	.22	.25	.42	.13	-.13	-.12	-.13	-.15	-.15	-.16	-.47
Average Wellhead Price	.45	1.31	2.60	2.60	2.63	2.65	2.73	2.87	3.08	3.42	5.68
Delivered Prices by Sectors											
Residential	2.65	3.68	5.95	6.01	6.10	6.26	6.41	6.60	6.88	7.30	10.16
Commercial[6]	1.93	3.21	5.56	5.58	5.63	5.77	5.90	6.08	6.34	6.74	9.53
Industrial	1.01	2.45	4.29	4.27	4.36	4.46	4.57	4.75	5.02	5.41	8.05
Electric Utilities	.78	2.11	3.48	3.44	3.30	3.35	3.39	3.56	3.84	4.25	6.19
Average to all Sectors[10]	1.49	2.85	4.82	4.83	4.91	5.06	5.18	5.33	5.58	5.97	8.60

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures.

[3] Includes net stock withdrawals for dry natural gas from underground storage, and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Discrepancy represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definitions, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) and Energy Information Administration, *Natural Gas Annual*, 1982 DOE/EIA-0131(82) (Washington, D.C., 1983). Projected values are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981 and quantities thru 1983.

Table B18. *Coal Supply, Disposition, and Prices*
(Million Short Tons per Year)
(1983 Dollars per Short Ton)

Supply, Disposition, and Price	Low Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	503	553	578	590	601	615	633	652	737
West of the Mississippi	76	183	282	300	322	338	348	363	382	399	468
Total	599	670	785	853	900	928	949	978	1,014	1,051	1,205
Imports[2]	0	3	1	1	0	0	0	0	0	0	0
Exports[3]	54	41	78	79	83	86	90	94	99	105	116
Net Imports	-54	-38	-77	-78	-83	-86	-90	-94	-99	-105	-116
Net Storage Withdrawals[4]	12	11	28	-5	-6	-5	-4	-5	-7	-7	-8
Total Supply[5]	557	644	736	770	811	837	856	879	909	940	1,081
Consumption by Sector											
Residential and Commercial	11	10	9	8	7	7	7	7	7	7	6
Industrial	68	63	64	67	73	76	79	82	84	86	91
Coking Plants[6]	94	71	37	46	48	49	50	51	51	52	54
Transportation	0	0	0	0	0	0	0	0	0	0	0
Electric Utilities	389	481	626	663	679	700	714	734	761	789	924
Total End-Use Consumption	562	625	735	784	807	832	851	874	903	934	1,076
Discrepancy[7]	-5	19	1	-14	4	5	5	5	6	6	6
Average Minemouth Price[8]	17.58	31.49	28.14	29.32	29.43	29.54	29.78	29.94	30.13	30.37	31.71
Delivered Prices by Sector											
Residential and Commercial[9]	35.24	59.58	46.05	49.97	50.81	51.40	51.94	52.65	53.50	54.26	61.89
Industrial	21.20	43.68	42.54	48.84	48.60	49.70	50.69	51.72	52.87	53.92	63.52
Coking Plants[6]	37.50	74.93	59.74	64.65	64.77	65.41	66.06	66.81	67.60	68.32	74.29
Electric Utilities[10]	20.95	39.49	[11] 36.44	37.57	38.60	38.78	39.08	39.23	39.50	39.94	44.87
Average to All End-Use Sectors[12]	24.03	44.27	38.26	40.26	41.18	41.46	41.85	42.11	42.46	42.91	48.02

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.
[2] Excludes coke imports.
[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.
[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.
[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.
[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents coal used for synthetic fuel production, and errors due to conversion factors.
[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.
[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.
[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.
[11] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated average coal price is $35.17 per short ton.
[12] Weighted average price and the weights are the sectoral consumption values.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation*, (DOE/NBB-0029)/1 (Washington, D.C., 1982) pp. 186-93, Tables B10, B11, B12, and B13. Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.
Historical prices thru 1981 and quantities thru 1982.

Appendix C
High World Oil Price Case

Appendix C
High World Oil Price Case

In the high world oil price case (Case C), total primary energy consumption would be about 3.9 percent lower in 1995 compared to the midprice case (Case A).

Total oil consumption in 1995 is about 9.4 percent lower in the high world oil price case then in the middle world oil price case, while domestic oil production in the high world oil price case is about 19 percent higher than in the middle world oil price case. The "Guide to Key Tables," "Location of Key Solution Values," and, "Appendix Data Sources," appearing in Appendix A refer to the tables listed in this appendix as well. Key assumptions for this case include:

	World Oil Price (1983 Dollars)	Real GNP (Billion 1983 dollars)	Total Industrial Production Index (1967=1.00)
1983	29.35	3,312	1.46
1984	29.91	3,461	1.56
1985	30.53	3,564	1.64
1986	31.14	3,674	1.70
1987	34.12	3,797	1.77
1988	38.18	3,919	1.90
1989	41.78	4,023	1.95
1990	45.64	4,125	1.99
1991	50.66	4,213	1.99
1992	53.81	4,302	2.02
1993	56.88	4,396	2.07
1994	60.54	4,492	2.12
1995	65.89	4,591	2.18

Table C1. Yearly Supply and Disposition Summary of Total Energy

(Quadrillion Btu per Year)

Total Supply and Disposition	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Supply											
Production											
Crude Oil and Lease Condensate	19.5	18.4	18.3	18.4	18.6	18.9	19.1	19.7	20.1	20.0	21.7
Natural Gas Plant Liquids	2.6	2.2	2.2	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.1
Natural Gas[1]	22.2	19.5	16.3	17.5	16.9	16.7	16.6	17.0	16.9	16.9	15.8
Coal[2]	13.9	14.9	17.3	19.1	20.0	20.6	21.0	21.5	22.2	22.9	25.8
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[3]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Production	62.0	61.1	61.0	64.2	65.4	66.5	67.6	69.5	71.0	71.9	75.8
Imports											
Crude Oil[4]	6.9	13.5	7.0	8.6	8.4	8.4	8.3	7.8	7.1	7.0	5.2
Refined Petroleum Products[5]	6.6	4.4	3.5	3.8	3.6	3.7	3.7	3.5	3.7	3.8	4.0
Natural Gas[6]	1.1	1.0	1.1	.9	1.2	1.2	1.3	1.3	1.3	1.3	1.6
Other Imports[7]	.2	.4	.4	.4	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	13.5	13.7	13.7	12.9	12.3	12.4	11.2
Net Stock Withdrawals	-.4	.3	1.0	-.6	-.5	-.5	-.4	-.4	-.4	-.5	-.2
Adjustments[8]	-.1	-.6	.1	.3	.3	.3	.4	.3	.4	.5	.7
Total Supply[9]	76.3	80.0	74.2	77.5	78.8	80.0	81.2	82.4	83.3	84.2	87.5
Disposition											
Exports											
Oil	.5	.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[10]	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Refined Petroleum Products[11]	34.8	38.0	30.0	31.2	31.2	31.6	31.7	31.5	31.5	31.5	31.7
Natural Gas	22.5	20.0	17.4	18.3	18.2	18.0	18.0	18.4	18.4	18.4	17.8
Coal[12]	12.9	13.7	15.8	17.1	17.7	18.1	18.5	18.8	19.4	19.9	22.6
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydro/Other/Electricity Imports[13]	3.1	3.2	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.7
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total Consumption	74.2	78.0	70.5	73.9	74.9	76.1	77.2	78.2	79.0	79.8	82.8
Total Disposition	76.3	80.0	74.2	77.5	78.8	80.0	81.2	82.4	83.3	84.2	87.5

[1] Net dry natural gas: dry marketed production excluding nonhydrocarbon gases.
[2] Historical coal production includes bituminous, anthracite, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[3] Hydropower/Other includes geothermal power, wood refuse, and hydropower generated at electric utilities. Hydropower produced by the industrial sector is also included.
[4] Includes imports of crude oil for the Strategic Petroleum Reserve.
[5] Includes imports of unfinished oils and natural gas plant liquids.
[6] Includes imports of dry natural gas, liquefied natural gas, and supplemental natural gas.
[7] Includes electricity, coal, and coal coke imports.
[8] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces.
[9] Total supply is the sum of production, imports, adjustments, and net stock withdrawals.
[10] Includes electricity and coal coke exports.
[11] Includes natural gas plant liquids and crude oil consumed as a fuel.
[12] Excludes anthracite shipped overseas to U.S. Armed Forces and coal used for synthetic fuel production.
[13] Includes net electricity imports and renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available

SOURCE: Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 5-29, Tables 1, 2, 3, and 13. Projected values are outputs from the Intermediate Future Forecasting System. Historical quantities thru 1983.

Table C2. Yearly Supply and Disposition of Total Energy, Supply Detail
(Quadrillion Btu per Year)

Total Supply	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
World Oil Price[1]	8.35	20.69	29.35	29.91	30.53	31.14	34.12	38.18	41.78	45.64	65.89
Domestic Production											
Oil[2]	22.1	20.7	20.5	20.7	21.0	21.2	21.4	21.9	22.4	22.4	23.8
Natural Gas[3]	22.2	19.5	16.3	17.5	16.9	16.7	16.6	17.0	16.9	16.9	15.8
Coal[4]	13.9	14.9	17.3	19.1	20.0	20.6	21.0	21.5	22.2	22.9	25.8
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[5]	2.9	3.0	3.6	3.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Total Domestic Production	62.0	61.1	61.0	64.2	65.4	66.5	67.6	69.5	71.0	71.9	75.8
Imports											
Oil[6]	13.5	17.8	10.6	12.4	12.0	12.2	12.1	11.3	10.7	10.7	9.2
Natural Gas[7]	1.1	1.0	1.1	.9	1.2	1.2	1.3	1.3	1.3	1.3	1.6
Coal[8]	.0	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA
Other Imports[9]	.2	.4	.4	.3	.3	.3	.4	.4	.4	.4	.4
Total Imports	14.7	19.3	12.1	13.6	13.5	13.7	13.7	12.9	12.3	12.4	11.2
Net Storage Withdrawals											
Oil	-.3	.5	.5	-.1	.0	-.1	.0	.0	.0	.0	.0
Natural Gas	-.4	-.2	.5	.0	.0	.0	.0	.0	.0	.0	.0
Coal[10]	.3	.3	.5	-.1	-.1	-.1	-.1	-.1	-.1	-.1	-.2
SPR Fill Rate Additions (-)[11]	.0	-.3	-.5	-.4	-.3	-.3	-.3	-.3	-.3	-.3	.0
Net Stock Withdrawals	-.4	.3	1.0	-.6	-.5	-.5	-.4	-.4	-.4	-.5	-.2
Available Supply[12]											
Oil	35.3	39.1	31.6	32.9	32.9	33.3	33.4	33.2	33.1	33.1	32.9
Natural Gas	22.8	20.3	17.9	18.4	18.1	17.9	17.9	18.2	18.2	18.2	17.4
Coal	14.2	15.2	17.8	19.0	19.9	20.5	20.9	21.4	22.0	22.7	25.7
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Other Supply[13]	3.1	3.4	4.0	3.8	3.6	3.7	3.7	3.7	3.7	3.7	3.7
Total Supply (before adjustments)	76.3	80.6	74.1	77.3	78.4	79.7	80.9	82.0	82.9	83.8	86.8
Adjustments[14]	-.1	-.6	.1	.3	.3	.3	.4	.3	.4	.5	.7
Total Supply	76.3	80.0	74.2	77.5	78.8	80.0	81.2	82.4	83.3	84.2	87.5

[1] Average refiners acquisition cost in 1983 dollars per barrel.
[2] Oil includes crude oil, lease condensate, natural gas plant liquids, and other domestic refinery production.
[3] Net dry marketed production after removal of nonhydrocarbon gases.
[4] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite, with anthracite included in bituminous.
[5] Hydropower/Other production includes hydropower, geothermal power, and wood waste.
[6] Oil imports includes crude oil and refined petroleum products. Crude oil imports include imports for the Strategic Petroleum Reserve.
[7] Includes both dry natural gas imports from Canada and Mexico, liquefied natural gas imports from Algeria, and supplemental gas.
[8] Includes small amounts of coal/coke imports.
[9] Consists of net electricity imports from Canada.
[10] From consumer stocks (utility, coke plant, and industrial) only.
[11] SPR is the Strategic Petroleum Reserve.
[12] Available supply is the sum of domestic production, imports, and net stock withdrawals.
[13] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[14] Balancing item that includes gains, losses, miscellaneous blending components, unaccounted for supply, coal used for synthetic fuel production, anthracite shipped overseas to U.S. Armed Forces and certain secondary stock withdrawals.
[NA] = Not available
SOURCE: Historical values are taken from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984).
Historical prices thru 1981 and quantities thru 1983.

Table C3. Yearly Supply and Disposition of Total Energy, Disposition Detail

(Quadrillion Btu per Year)

Total Disposition	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Exports											
Oil[1]	0.5	0.8	1.6	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Natural Gas	.1	.1	.1	NA	NA	NA	NA	NA	NA	NA	NA
Coal	1.4	1.1	2.0	2.1	2.2	2.3	2.4	2.5	2.6	2.8	3.1
Other[2]	.1	.0	.0	NA	NA	NA	NA	NA	NA	NA	NA
Total Exports	2.1	1.9	3.7	3.6	3.9	3.9	4.0	4.1	4.3	4.4	4.7
Consumption											
Residential and Commercial											
Oil[3]	4.4	4.1	2.3	2.6	2.6	2.7	2.7	2.7	2.6	2.6	2.2
Natural Gas	7.6	7.6	7.1	7.5	7.5	7.5	7.5	7.5	7.5	7.4	6.8
Coal	.3	.2	.2	.2	.2	.2	.2	.2	.2	.2	.2
Total (excluding electricity)	12.3	11.9	9.6	10.2	10.3	10.3	10.3	10.3	10.3	10.2	9.2
Industrial											
Oil[4]	9.1	9.9	7.8	8.5	8.7	8.8	8.9	9.0	9.1	9.2	9.8
Natural Gas[5]	10.4	8.5	6.7	6.8	6.7	6.7	6.7	6.7	6.6	6.5	5.8
Coal[6]	4.0	3.3	2.4	3.0	3.1	3.2	3.3	3.3	3.4	3.4	3.4
Hydropower	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Net Imports of Coke	.0	.1	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	23.5	21.9	16.9	18.3	18.4	18.6	18.8	19.0	19.1	19.1	19.0
Transportation											
Oil[7]	17.8	20.0	18.4	18.5	18.6	18.7	18.8	18.7	18.6	18.5	18.3
Natural Gas[8]	.7	.5	.6	.9	.9	.9	.9	.9	.9	.9	.9
Coal	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0	.0
Total (excluding electricity)	18.5	20.5	19.0	19.5	19.5	19.7	19.7	19.6	19.5	19.4	19.2
Electric Utilities											
Oil	3.5	4.0	1.5	1.6	1.3	1.4	1.3	1.1	1.1	1.2	1.4
Natural Gas	3.7	3.3	3.0	3.1	3.2	3.0	3.0	3.3	3.4	3.6	4.3
Coal	8.7	10.3	13.2	14.0	14.4	14.8	15.0	15.3	15.8	16.3	19.0
Nuclear Power	.9	3.0	3.2	3.5	4.2	4.7	5.4	5.8	6.1	6.3	7.0
Hydropower/Other[9]	3.0	3.2	4.0	3.8	3.6	3.6	3.7	3.7	3.7	3.7	3.7
Total Consumption	19.9	23.7	25.0	25.9	26.7	27.5	28.3	29.3	30.2	31.1	35.4
Total Disposition	76.3	80.0	74.2	77.5	78.8	80.0	81.2	82.4	83.3	84.2	87.5

[1] Consists primarily of refined petroleum products.
[2] Consists of coal coke exports.
[3] Residential and Commercial oil consists of motor gasoline, distillate fuel, kerosene, residual fuel, and liquefied petroleum gases.
[4] Industrial oil consists of distillate fuel, kerosene, residual fuel, liquefied petroleum gases, special naphthas, miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, petroleum coke, still gas, other oils greater than 400 degrees used for chemical feedstocks, motor gasoline, and naphthas less than 400 degrees used for feedstock purposes, including refinery fuel consumption.
[5] Industrial natural gas is composed of lease and plant fuel use, refinery fuel use, and other industrial uses.
[6] Industrial coal is composed of steam and metallurgical (coking) coal.
[7] Transportation oil consists of motor gasoline, aviation gasoline, jet fuel, distillate fuel, residual fuel, lubricants, and liquefied petroleum gases.
[8] Transportation natural gas represents natural gas used as a fuel by pipeline compressors.
[9] Includes net electricity imports from Canada, hydropower, geothermal power, wood, waste, solar power, and wind power.
[NA] = Not available
SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA 0214(81) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1983.

Table C4. Consumption by Major Fuels and End Use Sectors
(Quadrillion Btu per Year)

Sector and Fuel	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	2.00	1.95	1.11	1.22	1.23	1.23	1.21	1.18	1.15	1.10	0.88
Kerosene	.23	.15	.07	.07	.07	.07	.07	.07	.07	.07	.05
Liquefied Petroleum Gas	.59	.52	.29	.25	.25	.25	.25	.25	.24	.23	.19
Natural Gas	4.98	4.98	4.60	4.63	4.62	4.61	4.61	4.60	4.59	4.56	4.23
Steam Coal	.11	.08	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity	1.98	2.30	2.56	2.59	2.65	2.71	2.78	2.85	2.93	3.00	3.35
Total	9.88	9.99	8.71	8.83	8.89	8.95	8.99	9.02	9.03	9.03	8.76
Commercial											
Distillate Fuel	.64	.67	.38	.43	.46	.48	.49	.50	.51	.51	.47
Kerosene	.06	.05	.05	.07	.07	.07	.08	.08	.08	.08	.08
Motor Gasoline	.09	.11	.09	.09	.08	.08	.08	.08	.08	.08	.08
Residual Fuel	.67	.53	.29	.39	.41	.43	.44	.45	.46	.46	.44
Liquefied Petroleum Gas	.10	.09	.05	.04	.04	.04	.04	.04	.04	.04	.04
Natural Gas[1]	2.65	2.64	2.49	2.82	2.85	2.87	2.88	2.88	2.87	2.85	2.60
Steam Coal	.15	.13	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity	1.52	1.81	2.12	2.32	2.41	2.49	2.57	2.64	2.71	2.78	3.10
Total	5.89	6.04	5.59	6.26	6.43	6.58	6.70	6.78	6.86	6.91	6.90
Industrial[2]											
Distillate Fuel	1.47	1.75	1.30	1.51	1.54	1.57	1.60	1.63	1.65	1.68	1.84
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Motor Gasoline	.26	.18	.13	.14	.14	.13	.13	.12	.11	.11	.09
Residual Fuel	1.86	1.72	.76	.94	.96	.97	.95	.93	.91	.89	.88
Liquefied Petroleum Gas	1.26	1.27	1.57	1.34	1.35	1.36	1.37	1.37	1.36	1.36	1.33
Petrochemical Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.19	1.20	1.21	1.21	1.20	1.19	1.21
Other Petroleum[4]	2.33	2.32	1.85	2.00	2.01	2.01	2.05	2.11	2.15	2.20	2.46
Natural Gas[5]	10.39	8.54	6.75	6.78	6.70	6.67	6.66	6.66	6.57	6.49	5.75
Steam Coal	1.54	1.40	1.46	1.70	1.77	1.85	1.91	1.97	2.01	2.05	2.08
Metallurgical Coal	2.45	1.86	.96	1.28	1.30	1.32	1.34	1.35	1.36	1.36	1.36
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03
Electricity	2.34	2.76	2.65	2.75	2.84	2.94	3.05	3.19	3.31	3.45	4.05
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	25.87	24.62	19.58	21.08	21.28	21.58	21.89	22.22	22.37	22.56	23.05

See footnotes at end of table.

Table C4. Consumption by Major Fuels and End Use Sectors —— Continued

(Quadrillion Btu per Year)

Sector and Fuel	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation											
Aviation Gasoline	0.08	0.07	0.05	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.11
Distillate Fuel	2.22	2.68	2.83	2.69	2.77	2.89	3.02	3.16	3.31	3.47	4.47
Jet Fuel[6]	2.13	2.14	2.13	2.27	2.37	2.46	2.50	2.50	2.48	2.46	2.41
Motor Gasoline	12.46	13.93	12.46	12.59	12.43	12.32	12.15	11.91	11.65	11.40	10.11
Residual Fuel	.73	.99	.73	.67	.69	.71	.73	.75	.76	.78	.84
Liquefied Petroleum Gas	.02	.01	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants and Waxes	.16	.18	.15	.25	.26	.27	.28	.29	.29	.30	.33
Natural Gas[7]	.74	.54	.57	.93	.92	.91	.91	.93	.93	.93	.89
Other Transportation[8]	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total	18.56	20.55	18.97	19.49	19.56	19.67	19.70	19.63	19.54	19.45	19.17
Electric Utilities											
Distillate Fuel	.27	.28	.10	.11	.02	.02	.01	.01	.03	.04	.11
Residual Fuel	3.24	3.71	1.44	1.48	1.31	1.34	1.30	1.12	1.10	1.13	1.31
Natural Gas	3.75	3.30	3.01	3.10	3.16	2.98	2.96	3.34	3.44	3.58	4.33
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.78	15.03	15.35	15.82	16.34	18.96
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.02	3.18	3.95	3.80	3.58	3.64	3.65	3.67	3.68	3.69	3.70
Total	19.85	23.74	24.96	25.91	26.69	27.48	28.34	29.28	30.18	31.12	35.41
Primary Energy Consumption											
Distillate Fuel	6.61	7.32	5.71	5.97	6.02	6.19	6.33	6.48	6.64	6.79	7.76
Kerosene	.45	.36	.27	.24	.25	.25	.25	.25	.25	.25	.22
Aviation Gasoline	.08	.07	.05	.08	.08	.09	.09	.09	.09	.10	.11
Motor Gasoline	12.80	14.21	12.69	12.82	12.66	12.54	12.36	12.11	11.85	11.59	10.28
Jet Fuel	2.13	2.14	2.13	2.27	2.37	2.46	2.50	2.50	2.48	2.46	2.41
Residual Fuel	6.49	6.95	3.22	3.47	3.36	3.45	3.43	3.25	3.24	3.26	3.46
Liquefied Petroleum Gas	1.98	1.89	1.94	1.64	1.65	1.66	1.66	1.66	1.65	1.64	1.56
Petrochemical Feedstocks	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Still Gas	1.07	1.29	1.12	1.20	1.19	1.20	1.21	1.21	1.20	1.19	1.21
Lubricants and Waxes	.40	.41	.35	.50	.51	.53	.55	.56	.57	.59	.66
Other Petroleum	2.10	2.09	1.65	1.75	1.75	1.75	1.78	1.83	1.87	1.91	2.13
Natural Gas	22.50	20.00	17.42	18.25	18.25	18.04	18.02	18.41	18.40	18.41	17.79
Steam Coal	10.46	11.87	14.89	15.84	16.38	16.80	17.12	17.49	18.01	18.56	21.19
Metallurgical Coal	2.45	1.86	.96	1.28	1.30	1.32	1.34	1.35	1.36	1.36	1.36
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[9]	3.06	3.21	3.99	3.83	3.61	3.67	3.69	3.70	3.71	3.72	3.73
Total Consumption	74.20	78.05	70.47	73.90	74.94	76.10	77.20	78.25	79.03	79.82	82.79
Electricity Consumption (all sectors)	5.84	6.89	7.33	7.66	7.90	8.15	8.41	8.69	8.96	9.24	10.51

[1] Commercial natural gas includes the Other category.

[2] Industrial includes all fuels consumed for heat and power, industrial feedstock and raw material uses, all fuels consumed by refineries, and natural gas used as lease and plant fuel.

[3] Petrochemical feedstocks includes still gas used for feedstock purposes, naphthas less than 400 degrees, and other oils greater than 400 degrees.

[4] Consists of jet fuel, plant condensate, unfractionated stream, miscellaneous, natural gasoline, unfinished oils, special naphthas, asphalt, lubricants, waxes, petroleum coke, aviation blending components, motor gasoline blending components, and road oil.

[5] Includes lease and plant fuel consumption of natural gas.

[6] Jet fuel includes naphtha and kerosene types.

[7] Consists of natural gas used as pipeline compressor fuel.

[8] Other transportation includes steam coal and electricity.

[9] Includes renewable facilities such as hydropower, geothermal power, wood, waste, solar power, and wind power. Electric utility consumption includes net electicity imports.

SOURCE: Historical quantities are taken from Energy Information Administration, *State Energy Data Report, 1960 to 1981*, DOE/EIA-0214 (82) (Washington, D.C., 1983) and Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984). Projected quantities are outputs from the Intermediate Future Forecasting System.
Historical quantities thru 1981.

Table C5. Prices by Major Fuels and End Use Sectors
(1983 Dollars per Million Btu)

Sector and Fuel	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Residential											
Distillate Fuel	3.37	5.13	7.88	7.95	8.06	8.18	8.74	9.54	10.27	11.08	15.28
Kerosene	3.85	5.94	8.28	8.35	8.46	8.58	9.17	10.00	10.76	11.61	15.98
Liquefied Petroleum Gas	7.40	6.86	8.80	8.76	8.78	8.89	9.18	9.64	10.14	10.79	13.80
All Petroleum Products	4.25	5.52	8.08	8.10	8.19	8.31	8.83	9.58	10.27	11.06	15.06
Natural Gas	2.60	3.62	5.80	5.87	6.05	6.25	6.45	6.72	7.07	7.52	11.13
Steam Coal[1]	2.39	3.66	2.05	2.10	2.13	2.16	2.18	2.21	2.24	2.28	2.59
Electricity	14.28	17.01	19.02	19.20	19.44	19.72	19.94	19.98	19.86	19.78	20.54
Average[2]	5.41	7.20	10.03	10.13	10.39	10.66	11.00	11.36	11.70	12.11	15.18
Commercial											
Distillate Fuel	2.78	4.53	6.42	6.49	6.60	6.71	7.27	8.07	8.79	9.60	13.77
Kerosene[3]	2.04	4.44	6.35	6.42	6.53	6.65	7.24	8.07	8.83	9.68	14.04
Motor Gasoline[4]	6.34	7.54	9.79	9.81	9.96	10.13	10.83	11.73	12.47	13.20	17.37
Residual Fuel	1.77	3.20	4.97	5.00	5.02	5.14	5.46	5.95	6.42	7.02	9.64
Liquefied Petroleum Gas	3.02	5.07	8.82	8.80	8.83	8.95	9.25	9.72	10.22	10.87	13.87
All Petroleum Products	2.54	4.29	6.44	6.29	6.34	6.44	6.90	7.56	8.17	8.88	12.42
Natural Gas[5]	1.89	3.16	5.42	5.45	5.60	5.77	5.95	6.20	6.54	6.98	10.45
Steam Coal[6]	.90	1.97	2.01	2.06	2.09	2.11	2.13	2.16	2.19	2.22	2.52
Electricity	13.51	16.83	19.20	19.41	19.71	20.02	20.26	20.34	20.21	20.14	21.10
Average[2]	5.03	7.51	10.73	10.69	10.94	11.22	11.54	11.87	12.15	12.52	15.42
Industrial											
Distillate Fuel	1.89	4.04	6.38	6.45	6.55	6.67	7.23	8.02	8.75	9.56	13.73
Kerosene	2.04	4.44	6.81	6.88	7.00	7.12	7.71	8.54	9.30	10.15	14.51
Motor Gasoline[4]	6.34	7.54	9.79	9.79	9.94	10.11	10.81	11.71	12.45	13.18	17.34
Residual Fuel	1.63	3.01	4.12	4.15	4.18	4.29	4.62	5.12	5.59	6.19	8.80
Liquefied Petroleum Gas	2.71	4.44	6.70	6.67	6.70	6.81	7.11	7.59	8.10	8.75	11.79
Petrochemical Feedstocks[7]	1.89	4.04	5.91	5.97	6.07	6.18	6.77	7.60	8.35	9.19	13.51
Still Gas[8]	1.89	4.04	6.29	6.36	6.47	6.59	7.15	7.95	8.67	9.49	13.67
Other Petroleum[9]	2.91	5.07	5.08	5.11	5.17	5.27	5.58	6.05	6.52	7.10	10.27
All Petroleum Products	2.34	4.22	5.92	5.89	5.96	6.07	6.52	7.17	7.78	8.50	12.15
Natural Gas[10]	.99	2.41	4.18	4.20	4.40	4.55	4.73	5.01	5.36	5.78	9.16
Steam Coal	.94	1.97	1.88	1.94	1.98	2.02	2.05	2.09	2.13	2.17	2.50
Metallurgical Coal	1.44	2.88	2.30	2.35	2.38	2.40	2.42	2.45	2.47	2.50	2.71
Net Coke Imports	3.31	7.30	6.52	6.66	6.75	6.82	6.88	6.94	7.02	7.09	7.69
Electricity	7.05	10.94	16.20	16.34	16.57	16.83	17.05	17.07	16.97	16.88	17.55
Average[2]	2.02	4.07	6.18	6.13	6.28	6.45	6.75	7.15	7.55	8.01	10.89

See footnotes at end of table.

Table C5. Prices by Major Fuels and End Use Sectors — Continued
(1983 Dollars per Million Btu)

Sector and Fuel	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Transportation[11]											
Aviation Gasoline	7.70	10.14	12.89	13.16	13.41	13.70	14.88	16.40	17.65	18.89	25.92
Distillate Fuel	3.23	4.76	8.67	8.73	8.84	8.96	9.52	10.32	11.04	11.85	16.03
Jet Fuel[12]	1.98	4.38	6.75	6.80	6.88	6.96	7.56	8.39	9.15	9.98	14.25
Motor Gasoline[13]	6.34	7.54	9.79	9.79	9.94	10.11	10.81	11.70	12.44	13.17	17.33
Residual Fuel[14]	1.31	2.17	3.36	3.38	3.41	3.53	3.85	4.34	4.82	5.42	8.05
Liquefied Petroleum Gas[15]	2.71	4.44	8.13	8.10	8.13	8.25	8.54	9.02	9.51	10.16	13.17
Lubricants and Waxes[16]	12.10	14.42	22.68	22.80	22.98	23.19	24.15	25.51	26.75	28.14	35.29
All Petroleum Products	5.28	6.63	9.13	9.23	9.34	9.47	10.11	10.96	11.69	12.45	16.55
Natural Gas[17]	.50	1.27	2.53	2.53	2.64	2.70	2.83	3.05	3.35	3.71	6.50
Electricity	13.17	16.55	18.47	18.63	18.97	19.30	19.52	19.61	19.48	19.42	20.46
Average[2]	5.09	6.50	8.93	8.91	9.03	9.16	9.78	10.59	11.30	12.03	16.09
Electric Utilities											
Distillate Fuel[18]	2.19	3.89	6.94	6.71	7.04	7.08	7.59	8.39	9.17	10.00	13.86
Residual Fuel	1.59	3.05	4.28	4.30	4.36	4.47	4.80	5.33	5.82	6.42	9.08
All Petroleum Products	1.64	3.11	4.46	4.46	4.40	4.51	4.82	5.36	5.90	6.53	9.43
Natural Gas	.76	2.04	3.37	3.40	3.59	3.72	3.88	4.18	4.51	4.90	7.82
Steam Coal	.94	1.85	[19] 1.72	1.78	1.82	1.83	1.85	1.86	1.88	1.90	2.13
Fossil Fuel Average	1.05	2.17	2.24	2.28	2.29	2.32	2.36	2.45	2.54	2.66	3.54
Average Price to All Users											
Distillate Fuel	2.88	4.63	7.82	7.79	7.92	8.04	8.62	9.42	10.16	10.98	15.24
Kerosene	2.96	5.07	7.11	7.20	7.30	7.41	7.98	8.80	9.54	10.37	14.68
Aviation Gasoline	7.70	10.14	12.89	13.16	13.41	13.70	14.88	16.40	17.65	18.89	25.92
Motor Gasoline	6.34	7.54	9.79	9.79	9.94	10.11	10.81	11.70	12.44	13.17	17.33
Jet Fuel	1.98	4.38	6.75	6.80	6.88	6.96	7.56	8.39	9.15	9.98	14.25
Residual Fuel	1.59	2.93	4.10	4.16	4.19	4.31	4.63	5.13	5.60	6.21	8.83
Liquefied Petroleum Gas	2.71	4.44	6.70	6.67	6.70	6.81	7.11	7.59	8.10	8.75	11.79
Petrochemical Feedstocks	1.89	4.04	5.91	5.97	6.07	6.18	6.77	7.60	8.35	9.19	13.51
Lubricants and Waxes	12.10	14.42	22.68	22.80	22.98	23.19	24.15	25.51	26.75	28.14	35.29
Other Petroleum Products	1.89	4.04	5.41	5.42	5.49	5.59	6.10	6.82	7.77	8.35	12.31
All Petroleum Products	3.88	5.41	7.86	7.83	7.94	8.05	8.61	9.38	10.04	10.75	14.50
Natural Gas	1.39	2.71	4.58	4.59	4.76	4.94	5.12	5.36	5.70	6.11	9.35
Coal	1.05	2.02	1.78	1.84	1.88	1.90	1.91	1.93	1.95	1.97	2.20
Electricity	11.18	14.53	18.05	18.23	18.49	18.77	18.99	19.02	18.90	18.81	19.56
Average	3.20	4.91	6.72	6.71	6.83	6.97	7.29	7.67	8.01	8.38	10.65

[1] Projected residential coal prices are delivered to dealer prices and do not include dealer mark-up.
[2] Weighted average of end-use fuel prices consists of the prices shown above and the appropriate weights from Table 4.
[3] Historical price for commercial kerosene is the price of industrial kerosene.
[4] Historical price for commercial and for industrial motor gasoline is the price of transportation motor gasoline.
[5] Commercial natural gas price is a weighted average of the commercial and other category.
[6] Historical price for commercial steam coal is the price of industrial steam coal at the State level. Projected prices do not include dealer mark-up, where applicable.
[7] Industrial distillate price is used in historical years (through 1981).
[8] The industrial distillate price is used. For 1983 forward, differences between the national prices of still gas and distillate fuel oil are due to differences in the regional composition of demand for these fuels.
[9] Industrial other price is a weighted average price for road oil, asphalt, lubricants, waxes, petroleum coke, special naphthas, and miscellaneous petroleum products.
[10] Industrial natural gas price is a weighted average of the lease and plant fuel price and the industrial price. In these reports, the natural gas price for industrial heat and power is used for the lease and plant fuel price, so both components of the average are the same.
[11] Transportation prices include the appropriate Federal excise tax and State road use taxes.
[12] Jet fuel price is for kerosene type jet fuel at retail.
[13] Gasoline price is an average for all types.
[14] Residual fuel price is for marine bunker.
[15] Historical price for transportation LPG is the price of industrial LPG.
[16] Historical price is the price of industrial lubricants.
[17] Transportation natural gas price is for pipeline fuel use only. The average wellhead price from Table 17 is used as a surrogate price.
[18] Historical price for electric utility distillate fuel oil is the price of electric utility kerosene.
[19] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated actual average coal price is $1.66 per million Btu.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Projected coal prices are based on cost estimates and do not reflect market conditions.

NOTE: Electricity and natural gas prices are average prices, revenue divided by sales. Also, the electricity prices are averages for class A and B private electric utilities and public power authorities.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1*, (DOE/NBB-0029)/1 (Washington, D.C., 1982), pp. 229-95, Tables, C1 through C29. Projected prices are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981.

Table C6. Residential Energy Use by End Use
(Quadrillion Btu per Year)

Fuel and End Use	High Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption[1]									
Total Fuel Use									
Space Heating	4.51	4.60	4.62	4.63	4.62	4.60	4.55	4.48	3.96
Water Heating	1.65	1.64	1.65	1.66	1.67	1.68	1.69	1.70	1.74
Air Conditioning	.37	.38	.39	.40	.41	.42	.43	.44	.49
Other End Uses[2]	2.17	2.20	2.23	2.26	2.29	2.32	2.36	2.39	2.57
Total	8.71	8.83	8.89	8.94	8.99	9.02	9.03	9.02	8.76
Liquefied Petroleum Gas									
Space Heating	.21	.18	.18	.18	.17	.17	.16	.16	.11
Water Heating	.09	.07	.07	.08	.08	.08	.08	.08	.08
Total	.29	.25	.25	.25	.25	.25	.24	.23	.19
Fuel Oil[3]									
Space Heating	.96	1.06	1.06	1.06	1.05	1.01	.97	.93	.69
Water Heating	.22	.24	.24	.24	.24	.24	.24	.24	.23
Total	1.18	1.30	1.30	1.30	1.28	1.25	1.21	1.16	.93
Natural Gas									
Space Heating	3.03	3.05	3.05	3.04	3.04	3.03	3.01	2.98	2.65
Water Heating	1.01	1.01	1.01	1.01	1.01	1.02	1.02	1.02	1.02
Air Conditioning	.01	.01	.01	.01	.01	.01	.01	.01	.01
Other End Uses[2]	.54	.55	.55	.55	.54	.54	.54	.55	.55
Total	4.60	4.63	4.62	4.61	4.61	4.60	4.59	4.56	4.23
Coal									
Space Heating	.08	.07	.07	.07	.06	.06	.06	.06	.05
Total	.08	.07	.07	.07	.06	.06	.06	.06	.05
Electricity									
Space Heating	.23	.25	.27	.28	.30	.32	.34	.36	.45
Water Heating	.33	.31	.32	.33	.34	.35	.36	.37	.41
Air Conditioning	.36	.37	.38	.39	.40	.41	.42	.43	.47
Other End Uses[2]	1.64	1.65	1.68	1.71	1.74	1.78	1.81	1.85	2.02
Total	2.56	2.59	2.65	2.71	2.78	2.85	2.93	3.00	3.35
Non-Marketed Fuel Consumption[1]									
Wood	0.89	0.92	0.94	0.96	0.98	1.00	1.02	1.04	1.15
Residential Activity									
Occupied Housing Stock (million units)	85.0	86.5	88.1	89.6	91.2	92.8	94.5	96.1	103.3
New Housing Construction[4] (million units)	1.5	2.0	2.0	2.0	2.0	2.1	2.1	2.0	1.8
Income Per Household (thousand 1983 dollars)	21.1	21.7	22.0	22.3	22.5	22.5	22.6	22.6	23.0
Energy Use Per Household (million Btu)	103	102	101	100	99	97	96	94	85
Fuel Expenditure Per Household (1983 dollars)	1,026	1,033	1,046	1,062	1,082	1,101	1,117	1,136	1,285

[1] Residential fuels are divided into marketed fuels (those with an associated price that are traded in economic markets) and nonmarketed fuels.
[2] Major other end uses include lighting, cooking, refrigeration, washing, and drying.
[3] Residential fuel oil category includes kerosene and distillate oil.
[4] New housing construction includes completions of single family, multi-family, and mobile housing units.
SOURCE: The Residential model is documented in *Model Documentation: Household Model of Energy*, Energy Information Administration, DOE/EIA-0409, July 1983. The major model data source is the public use tape of the Residential Energy Consumption Survey 1981, Energy Information Administration.

Table C7. Commercial Energy Use by Building Type
(Quadrillion Btu per Year)

Fuel and Building Type	High Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
Marketed Fuel Consumption									
Total Fuel Use	5.60	6.26	6.43	6.57	6.70	6.78	6.86	6.91	6.90
Liquefied Petroleum Gas	.05	.04	.04	.04	.04	.04	.04	.04	.04
Motor Gasoline	.09	.09	.08	.08	.08	.08	.08	.08	.08
Fuel Oil[1]									
Office[2]	.25	.30	.32	.33	.34	.35	.35	.35	.33
Retail/Wholesale	.16	.19	.20	.21	.22	.22	.22	.22	.19
Warehouse	.12	.15	.16	.17	.18	.19	.20	.21	.22
Other Buildings[3]	.20	.24	.25	.26	.27	.28	.28	.28	.25
Total	.73	.88	.93	.98	1.01	1.03	1.05	1.05	.99
Natural Gas									
Office[2]	.70	.80	.80	.81	.81	.81	.81	.80	.74
Retail/Wholesale	.70	.81	.83	.84	.85	.86	.86	.86	.82
Warehouse	.37	.39	.39	.39	.39	.39	.39	.39	.35
Other Buildings[3]	.72	.82	.83	.83	.83	.82	.81	.80	.69
Total	2.49	2.82	2.85	2.87	2.88	2.88	2.87	2.85	2.60
Coal	.11	.11	.11	.11	.11	.11	.11	.11	.10
Electricity									
Office[2]	.81	.88	.92	.95	.98	1.00	1.03	1.06	1.17
Retail/Wholesale	.59	.67	.70	.73	.75	.77	.80	.82	.92
Warehouse	.30	.31	.33	.34	.35	.36	.37	.38	.43
Other Buildings[3]	.42	.45	.46	.48	.49	.50	.51	.52	.57
Total	2.12	2.32	2.41	2.49	2.57	2.64	2.71	2.78	3.10
Commercial Activity									
Building Floorspace Stock (billion square feet)	48.7	50.7	52.3	53.8	55.2	56.5	57.7	59.0	64.9
Office[2]	17.1	17.8	18.4	18.9	19.4	19.9	20.3	20.7	22.8
Retail/Wholesale	14.5	15.3	15.8	16.3	16.8	17.2	17.7	18.1	20.2
Warehouse	6.9	7.2	7.4	7.7	7.9	8.1	8.3	8.5	9.5
Other Buildings[3]	10.1	10.4	10.6	10.9	11.1	11.2	11.4	11.6	12.4
Energy Use Per Square Foot (thousand Btu)	115.1	123.5	122.9	122.2	121.3	120.1	118.8	117.2	106.3
Expenditures Per Square Foot (1983 dollars)	1.20	1.29	1.32	1.34	1.37	1.40	1.41	1.44	1.61

[1] The commercial fuel oil category includes kerosene, distillate oil, and residual oil.
[2] Office includes offices, educational buildings, laboratories, health clinics, and some public buildings.
[3] Other Buildings includes assembly buildings, hotels/motels, hospitals, parking garages, and jails.
SOURCE: The Commercial model is documented in *A Model of Commercial Energy Use Based Macroeconomic Data*, Brookhaven National Laboratory, April 1983. The major model source is the public use tape of the Non-Residential Energy Consumption Survey 1980, Energy Information Administration.

Table C8. Industrial Energy Use
(Quadrillion Btu per Year)

Fuel and End Use	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Industrial Heat and Power											
Distillate Fuel	1.44	1.70	1.29	1.50	1.53	1.57	1.59	1.62	1.64	1.67	1.83
Residual Fuel	1.58	1.40	.65	.82	.84	.86	.84	.82	.81	.79	.77
Liquefied Petroleum Gas	.11	.16	.64	.33	.33	.34	.34	.34	.34	.34	.35
Natural Gas	8.50	7.08	5.56	5.54	5.46	5.42	5.41	5.41	5.33	5.25	4.56
Steam Coal[1]	1.54	1.40	1.46	1.70	1.77	1.85	1.91	1.97	2.01	2.05	2.08
Electricity[2]	2.34	2.76	2.54	2.64	2.73	2.83	2.94	3.08	3.20	3.34	3.95
Total	15.51	14.51	12.14	12.53	12.67	12.86	13.04	13.23	13.33	13.44	13.54
Refinery Fuel											
Distillate Fuel	.03	.05	.01	.01	.01	.01	.01	.01	.01	.01	.01
Residual Fuel	.28	.31	.11	.11	.11	.12	.11	.11	.11	.10	.11
Liquefied Petroleum Gas	.04	.06	.03	.03	.03	.03	.03	.03	.03	.03	.03
Still Gas	1.07	1.29	1.12	1.20	1.19	1.20	1.21	1.21	1.20	1.19	1.21
Petroleum Coke	.40	.39	.30	.29	.29	.30	.30	.30	.29	.29	.30
Other Petroleum	.00	.00	.01	.01	.01	.01	.01	.01	.01	.01	.01
Electricity	NA	NA	.11	.11	.11	.11	.11	.11	.11	.11	.11
Natural Gas	1.11	.82	.69	.69	.69	.70	.70	.70	.70	.70	.71
Total	2.93	2.93	2.37	2.46	2.44	2.47	2.48	2.48	2.46	2.45	2.48
Feedstocks, Raw Materials, and Other Fuel Uses											
Motor Gasoline	.26	.18	.13	.14	.14	.13	.13	.12	.11	.11	.09
Kerosene	.16	.16	.14	.10	.10	.10	.10	.10	.10	.10	.09
Petroleum Feedstocks[3]	.73	1.22	.88	1.32	1.37	1.44	1.51	1.57	1.62	1.67	1.92
Liquefied Petroleum Gas[4]	1.11	1.05	.90	.98	.99	.99	1.00	1.00	1.00	.99	.94
Special Naphthas	.17	.20	.15	.20	.21	.22	.22	.22	.21	.21	.19
Lubricants and Waxes	.23	.23	.20	.25	.26	.26	.27	.28	.28	.29	.33
Petroleum Coke	.16	.16	.16	.27	.28	.28	.28	.27	.26	.26	.23
Asphalt and Road Oil	1.26	1.16	.90	1.08	1.10	1.10	1.10	1.10	1.09	1.07	.96
Other Raw Materials[5]	.11	.18	.13	-.11	-.14	-.15	-.13	-.07	.00	.07	.44
Metallurgical Coal[1]	2.45	1.86	.96	1.28	1.30	1.32	1.34	1.35	1.36	1.36	1.36
Natural Gas Raw Materials[6]	.78	.63	.49	.55	.55	.55	.55	.55	.54	.53	.48
Net Coke Imports	-.01	.13	-.02	-.02	-.02	-.02	-.02	-.02	-.03	-.03	-.03
Hydropower	.03	.03	.03	.04	.04	.04	.04	.04	.04	.04	.04
Total	7.43	7.18	5.07	6.08	6.17	6.26	6.38	6.51	6.59	6.67	7.03
Total Industrial Demand	25.87	24.62	19.58	21.08	21.28	21.58	21.89	22.22	22.37	22.56	23.05

[1] Includes refinery steam coal. The metallurgical coal estimates for 1983 and 1984 are not fully comparable, in part because of different Btu conversion factors.
[2] Includes refinery electricity before 1980.
[3] Petrochemical feedstocks includes naphthas less than 400 degrees, other oils greater than 400 degrees, and some still gas.
[4] The LPG price for Industrial Heat and Power is used for LPG feedstocks in weighted average price calculations.
[5] Other products includes jet fuel, plant condensate, unfractionated stream, some still gas, miscellaneous, natural gasoline, unfinished oils, aviation blending components, and motor gasoline blending components.
[6] The natural gas price for Industrial Heat and Power is used for natural gas raw materials in weighted average price calculations.
[NA] = Not available
SOURCE: The Industrial model is documented in *Documentation of the PURHAPS Industrial Demand Model, Vol 1: Model Description, Overview, and Assumptions for the 1983 Annual Energy Outlook*, DOE/EIA-0420/1 (Washington, D.C., 1984)
Historical quantities thru 1981.

Table C9. Transportation Sector Energy Use By Mode

Fuel and Mode of Transportation	High Price								
	1983	1984	1985	1986	1987	1988	1989	1990	1995
All Modes[1]									
Aviation Gasoline	0.05	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.11
Distillate Fuel	2.83	2.69	2.77	2.89	3.02	3.16	3.31	3.47	4.47
Jet Fuel	2.13	2.27	2.37	2.46	2.50	2.50	2.48	2.46	2.41
Motor Gasoline	12.46	12.59	12.43	12.32	12.15	11.91	11.65	11.40	10.11
Residual Fuel	.73	.67	.69	.71	.73	.75	.76	.78	.84
Liquefied Petroleum Gas	.03	.01	.01	.01	.01	.01	.01	.01	.01
Lubricants	.15	.25	.26	.27	.28	.29	.29	.30	.33
Natural Gas	.57	.93	.92	.91	.91	.93	.93	.93	.89
Electricity	.01	.01	.01	.01	.01	.01	.01	.01	.01
Total Consumption	18.97	19.49	19.56	19.67	19.70	19.63	19.54	19.45	19.17
Automobiles									
Vehicle-Miles Travelled[2]	1,155.1	1,249.0	1,324.9	1,400.9	1,462.2	1,506.5	1,544.8	1,578.4	1,717.8
Fleet-Miles per Gallon	16.5	17.5	18.7	19.8	21.0	22.1	23.2	24.2	29.1
Total Fuel Use[3]	69.9	71.4	70.9	70.6	69.7	68.2	66.7	65.2	59.1
Trucks									
Vehicle-Miles Travelled[2]	451.7	483.2	509.6	538.9	571.3	606.4	643.2	681.5	889.7
Fleet-Miles per Gallon	10.5	11.0	11.7	12.3	13.0	13.6	14.3	15.0	18.4
Total Fuel Use[3]	42.9	43.7	43.6	43.7	44.0	44.5	45.0	45.5	48.2
Air									
Revenue Passenger Miles[2]	290.6	323.0	354.8	384.0	404.3	416.1	426.4	434.3	481.4
Fuel Burned Per Seat Mile[4]	.023	.022	.022	.021	.020	.019	.018	.017	.014
Total Jet Fuel[3]	15.9	17.0	17.8	18.4	18.7	18.7	18.6	18.4	18.1
Aviation Gasoline[3]	.4	.7	.7	.7	.7	.8	.8	.8	.9
Selected Fuel Expenditures[5]									
Motor Gasoline	122.1	123.2	123.5	124.6	131.3	139.3	145.0	150.2	175.2
Distillate Fuel	24.5	23.5	24.5	25.9	28.7	32.6	36.5	41.1	71.7

[1] Quadrillion Btu per year.
[2] Billion per year.
[3] Billion gallons per year.
[4] Gallons.
[5] Billion 1983 Dollars per Year.

Table C10. Electric Utility Fuel Consumption and Electricity Sales
(Quadrillion Btu per Year)

Fuel Consumption and Sales	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Fuel Inputs											
Oil											
Distillate	0.27	0.28	0.10	0.11	0.02	0.02	0.01	0.01	0.03	0.04	0.11
Residual LS[1]	NA	NA	.81	.86	.85	.87	.85	.78	.77	.80	.92
Residual HS[1]	3.24	3.71	.63	.61	.46	.47	.45	.34	.33	.34	.39
Natural Gas	3.75	3.30	3.01	3.10	3.16	2.98	2.96	3.34	3.44	3.58	4.33
Steam Coal	8.66	10.25	13.23	13.96	14.42	14.78	15.03	15.35	15.82	16.34	18.96
Nuclear Power	.91	3.02	3.22	3.47	4.20	4.72	5.39	5.80	6.11	6.34	7.01
Hydropower/Other[2]	2.87	2.97	3.61	3.48	3.25	3.29	3.30	3.30	3.30	3.30	3.30
Total Fuel Inputs	19.70	23.53	24.61	25.59	26.36	27.14	27.99	28.92	29.81	30.73	35.01
Net Imports	.15	.20	.35	.32	.33	.34	.35	.36	.37	.39	.40
Total Electricity Inputs	19.85	23.74	24.96	25.91	26.69	27.48	28.34	29.28	30.18	31.12	35.41
Disposition											
Total Electricity Inputs	19.85	23.74	24.96	25.91	26.69	27.48	28.34	29.28	30.18	31.12	35.41
Minus Conversion Losses[3]	13.50	16.21	17.08	17.61	18.13	18.67	19.25	19.90	20.51	21.15	24.07
Equals Generation	6.35	7.53	7.88	8.30	8.55	8.81	9.09	9.38	9.67	9.97	11.34
Minus Transportation and Distribution Losses	.51	.64	.55	.64	.65	.66	.68	.69	.71	.72	.83
Equals Electricity Sales	5.84	6.89	7.33	7.66	7.90	8.15	8.41	8.69	8.96	9.24	10.51
Electricity Sales by End-Use Sector											
Residential	1.98	2.30	2.56	2.59	2.65	2.71	2.78	2.85	2.93	3.00	3.35
Commercial/Other[4]	1.53	1.82	2.13	2.33	2.42	2.50	2.58	2.65	2.72	2.79	3.11
Industrial	2.34	2.76	2.65	2.75	2.84	2.94	3.05	3.19	3.31	3.45	4.05
Total Electricity Sales	5.84	6.89	7.33	7.66	7.90	8.15	8.41	8.69	8.96	9.24	10.51

[1] Prior to 1983, only the total of high-sulfur and low-sulfur residual oil is available, and is reported here as high-sulfur.
[2] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[3] Conversion losses includes net imports.
[4] Commercial/Other includes street lighting and the transportation sector.
[NA] = Not available
SOURCE: Historical quantities thru 1983.

Table C11. Electric Utility Sectoral Prices and Demands
(Billion Kilowatthours per Year)
(1983 Dollars per Thousand Kilowatthours)

Prices and Demands	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Prices[1]											
Residential	48.7	58.0	64.9	65.5	66.3	67.3	68.0	68.2	67.8	67.5	70.1
Commercial[2]	46.1	57.4	65.5	66.2	67.2	68.3	69.1	69.4	69.0	68.7	72.0
Industrial	24.1	37.3	55.3	55.8	56.5	57.4	58.2	58.3	57.9	57.6	59.9
All Sectors	38.1	49.6	61.7	62.2	63.1	64.0	64.8	64.9	64.5	64.2	66.7
Demands											
Residential	579	674	749	758	777	796	815	836	858	880	982
Commercial[2]	447	534	624	682	709	733	756	777	798	818	910
Industrial	686	809	776	806	831	861	894	934	971	1,012	1,189
All Sectors	1,713	2,018	2,149	2,246	2,316	2,390	2,465	2,547	2,627	2,710	3,081

[1] Prices for 1983-95 are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.
[2] This category includes consumption for street and highway lighting, other public authorities, and railroads and railways.
SOURCE: Prices for 1973 and 1978 are from the Energy Information Administration, *State Energy Price System, Volume 1*, DOE/NBB-0029/1, (Washington, D.C., 1982). Demands for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984).

Table C12. Electric Utility Capacity and Generation

(Generation in Billion Kilowatthours per Year)

(Capacity in Million Kilowatts)

Capacity and Generation	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Capacity[1]											
Coal Steam	320.6	399.5	454.1	297.7	305.6	312.2	317.8	324.3	329.7	335.5	364.8
Natural Gas Steam	–	–	–	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4
Oil Steam	–	–	–	51.4	51.4	51.4	51.4	51.4	51.4	51.4	51.4
Natural Gas/Oil Steam	–	–	–	99.8	99.8	99.8	99.8	99.8	99.8	99.8	99.8
Natural Gas Combined Cycle	–	–	–	5.6	5.6	5.6	5.6	5.6	5.6	5.6	5.6
Oil Combined Cycle	–	–	–	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Natural Gas Turbine	38.4	54.5	56.6	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Oil Turbine	–	–	–	24.5	24.5	24.5	24.5	24.5	24.6	24.7	24.9
Natural Gas/Oil Turbine	–	–	–	24.7	24.7	24.8	24.8	24.9	25.2	25.5	36.9
Nuclear Power	21.0	53.5	66.0	73.6	84.8	94.3	104.3	104.8	107.1	110.8	119.2
Hydropower/Other[2]	62.4	71.6	80.3	69.9	71.3	72.0	72.1	72.5	72.6	72.6	72.7
Pumped Storage Hydropower[3]	–	–	–	14.3	15.4	16.4	18.3	18.8	18.8	18.8	18.9
Total Capacity	442.4	579.2	657.0	678.4	700.0	717.9	735.5	743.5	751.7	761.6	811.1
Generation by Plant Type[1]											
Coal Steam	1,467	1,610	1,662	1,351	1,398	1,434	1,460	1,492	1,539	1,590	1,850
Natural Gas Steam	–	–	–	54	56	59	62	65	67	68	67
Oil Steam	–	–	–	95	103	107	104	77	74	75	87
Natural Gas/Oil Steam	–	–	–	230	211	197	192	228	235	247	285
Natural Gas Combined Cycle	–	–	–	33	30	29	28	30	30	30	33
Oil Combined Cycle	–	–	–	1	0	0	0	0	0	1	1
Natural Gas Turbine	37	36	16	2	1	1	1	1	2	2	3
Oil Turbine	–	–	–	7	2	1	1	1	2	2	7
Natural Gas/Oil Turbine	–	–	–	7	8	5	5	6	7	8	31
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
Hydropower/Other[2]	274	283	338	342	320	326	328	330	330	330	330
Pumped Storage Hydropower[3]	–	–	–	-7	-7	-9	-11	-12	-12	-12	-12
Total Generation	1,861	2,206	2,309	2,433	2,507	2,583	2,664	2,750	2,834	2,921	3,325
Generation by Fuel Type											
Coal[4]	848	976	1,259	1,345	1,392	1,427	1,453	1,485	1,532	1,583	1,843
Natural Gas	341	305	274	285	291	276	274	308	317	329	389
Oil	314	365	145	150	127	130	124	107	107	110	132
Nuclear Power	83	276	292	318	385	433	494	532	560	581	643
All Hydropower/Other[5]	274	283	338	335	313	317	317	318	318	318	318
Total Generation	1,861	2,206	2,309	2,433	2,507	2,583	2,664	2,750	2,834	2,921	3,325

[1] Historical data for 1973, 1978, and 1983 are given by prime mover only. Thus for the historical period, all steam and combined cycle capacity and generation is shown in the coal steam category; all turbine and internal combustion capacity and generation are shown in the natural gas turbine category; and all conventional hydroelectric, pumped storage hydroelectric, and other renewable capacity and generation is shown in the hydropower/other category.

[2] This category includes other renewable sources such as geothermal, wood, waste, solar, and wind.

[3] See Appendix E, electricity terminology for definition of pumped storage plant.

[4] Generation by coal and generation by coal steam plants are not identical because small amounts of oil and natural gas are used in coal steam plants for startup and flame stability.

[5] This category includes conventional and pumped storage hydropower and other renewable sources such as geothermal, wood, waste, solar, and wind.

SOURCE: Data for 1973, 1978, and 1983 are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83), (Washington, D.C., April 1984). Capacity data for projection years 1984-95 are based on the Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table C13. Electric Utility Capacity Additions
(Thousand Kilowatts)

Additions: Pipeline and New Starts	High Price												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Total Additions													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	5,922	5,264	5,820
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	1,116	2,239	2,613	3,081	2,557
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total New Capacity	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	9,744	12,288	10,832	8,345	8,377
Pipeline[6]													
Nuclear Power	3,071	[1] 9,965	11,175	9,523	10,010	492	2,355	3,697	2,350	3,699	2,270	0	0
Coal Steam	6,196	9,300	7,958	6,568	5,559	6,523	5,421	5,831	6,221	6,083	3,915	1,450	400
Other Steam[2]	64	0	0	0	0	0	0	0	0	48	0	0	0
Turbines[3]	268	3	6	44	49	50	402	333	361	71	0	0	50
Pumped Storage Hydro[4]	1,411	0	1,050	1,050	1,848	500	0	0	0	150	0	0	0
Hydropower/Other[5]	1,021	456	1,380	755	63	445	43	11	57	70	26	0	0
Total Pipeline	12,031	19,724	21,568	17,939	17,529	8,010	8,221	9,872	8,989	10,120	6,212	1,450	450
New Starts[7]													
Nuclear Power	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	0	2,007	3,814	5,420
Other Steam[2]	0	0	0	0	0	0	0	0	0	0	0	0	0
Turbines[3]	0	0	0	0	0	0	0	0	755	2,168	2,613	3,081	2,507
Pumped Storage Hydro[4]	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydropower/Other[5]	0	0	0	0	0	0	0	0	0	0	0	0	0
Total New Starts	0	0	0	0	0	0	0	0	755	2,168	4,620	6,895	7,927

[1] Includes the scheduled return to service of the Three Mile Island 1 facility.
[2] Includes natural gas, oil, and dual fired oil/natural gas steam capacity
[3] Includes all gas turbine and internal combustion capacity
[4] See Appendix E, electricity terminology for definition of pumped storage plant.
[5] Includes conventional hydroelectric and other renewable sources of power such as geothermal, wood, waste, solar, and wind.
[6] Includes all new capacity announced by the electric utility industry.
[7] Includes additional new capacity considered necessary to meet projected electricity demands.

SOURCE: The Energy Information Administration Generating Unit Reference File (GURF); the Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, FERC-0070, January 1, 1980; Energy Information Administration, *U.S. Commercial Nuclear Power*, DOE/EIA-0314, (Washington, D.C., March 1982); and the Energy Information Administration Form-254: "Quarterly Progress Report on the Status of Reactor Construction."

Table C14. Summary of Components of Electricity Price
(1983 Dollars per Thousand Kilowatthours)

Price Components	High Price												
	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Capital Component[1]	24.5	24.7	25.3	26.0	26.6	26.3	25.2	24.0	23.1	22.2	21.3	20.5	19.7
Fuel Component[2]	22.2	22.5	22.5	22.5	22.6	23.2	23.9	24.9	26.4	27.6	29.3	30.9	32.3
O&M Component[3]	14.9	15.0	15.3	15.5	15.6	15.5	15.4	15.3	15.2	15.1	15.0	14.9	14.8
Total Price[4]	61.7	62.2	63.1	64.0	64.8	64.9	64.5	64.2	64.7	65.0	65.6	66.3	66.7

[1] The capital component represents the cost to the utility of capital assets needed to provide reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[2] The fuel component includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[3] The operation and maintenance (O&M) component includes all nonfuel costs necessary to operate and maintain generation, transmission and distribution capacity used to deliver electricity to end-use sectors.
[4] All prices are from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry. Revenue requirements are projected from the financial information contained on the Federal Energy Regulatory Commission Form 1 and Form 1-M and on the Energy Information Administration Form 412.

Table C15. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Crude Oil[1]	9.21	8.71	8.65	8.65	8.75	8.86	8.96	9.23	9.42	9.37	9.89
Alaska North Slope	.00	1.09	1.64	1.65	1.71	1.80	1.84	1.83	1.89	1.78	1.31
Subarctic	9.21	7.62	7.02	7.00	7.04	7.06	7.12	7.40	7.53	7.59	8.58
Natural Gas Plant Liquids	1.74	1.57	1.56	1.58	1.64	1.63	1.60	1.59	1.63	1.63	1.50
Other Domestic[2]	.01	.01	.05	.05	.05	.05	.05	.06	.07	.09	.34
Processing Gain[3]	.45	.50	.48	.51	.49	.49	.50	.49	.49	.49	.49
Total Production	11.40	10.78	10.74	10.80	10.93	11.03	11.11	11.37	11.61	11.58	12.22
Imports (including SPR)											
Crude Oil[4]	3.24	6.36	3.30	4.05	3.96	3.98	3.93	3.66	3.33	3.29	2.46
Refined Products	3.01	2.01	1.69	1.81	1.71	1.77	1.77	1.69	1.74	1.79	1.89
Total Imports	6.26	8.36	4.99	5.86	5.67	5.75	5.70	5.35	5.07	5.08	4.35
Exports											
Crude Oil	.00	.16	.16	.18	.17	.17	.17	.17	.17	.17	.17
Refined Products	.23	.20	.57	.54	.61	.61	.61	.61	.61	.61	.61
Total Exports	.23	.36	.74	.72	.78	.78	.78	.78	.78	.78	.78
Net Imports (including SPR)	6.02	8.00	4.25	5.14	4.89	4.97	4.92	4.57	4.29	4.29	3.57
Primary Stock Changes											
Net Withdrawals[5]	-.14	.26	.26	-.06	-.01	-.03	-.02	-.01	.00	.00	-.02
SPR Fill Rate Additions (-)[6]	.00	-.16	-.23	-.17	-.14	-.14	-.14	-.14	-.14	-.14	.00
Total Primary Supply[7]	17.29	18.87	15.02	15.71	15.66	15.82	15.86	15.79	15.75	15.72	15.77
Refined Petroleum Products											
Motor Gasoline	6.67	7.41	6.62	6.70	6.60	6.54	6.44	6.31	6.18	6.04	5.36
Aviation Gasoline	.05	.04	.03	.04	.04	.05	.05	.05	.05	.05	.06
Jet Fuel[8]	1.06	1.06	1.04	1.11	1.16	1.20	1.22	1.22	1.21	1.20	1.18
Kerosene	.22	.18	.13	.12	.12	.12	.12	.12	.12	.12	.11
Distillate Fuel	3.09	3.43	2.68	2.80	2.83	2.91	2.98	3.04	3.12	3.19	3.65
Residual Fuel	2.82	3.02	1.40	1.51	1.47	1.50	1.49	1.42	1.41	1.42	1.51
Liquid Petroleum Gas	1.45	1.41	1.47	1.23	1.24	1.25	1.25	1.25	1.24	1.23	1.18
Petrochemical Feedstocks	.36	.59	.41	.64	.67	.70	.74	.77	.79	.82	.94
Other Petroleum Products[9]	1.59	1.70	1.37	1.54	1.54	1.55	1.58	1.61	1.63	1.65	1.79
Total Product Supplied	17.31	18.85	15.15	15.69	15.67	15.82	15.87	15.79	15.76	15.73	15.77
Refined Petroleum Products Supplied to End-Use Sectors											
Residential and Commercial	2.23	2.07	1.20	1.28	1.30	1.32	1.33	1.32	1.31	1.28	1.10
Industrial[10]	4.49	4.89	4.01	4.32	4.37	4.44	4.50	4.56	4.59	4.63	4.91
Transportation	9.03	10.13	9.31	9.39	9.42	9.47	9.47	9.42	9.37	9.31	9.13
Electric Utilities	1.54	1.75	.67	.69	.58	.59	.57	.49	.49	.51	.62
Total End-Use Consumption	17.30	18.84	15.19	15.68	15.67	15.83	15.88	15.80	15.76	15.73	15.77
Discrepancy[11]	-.01	.03	-.17	.02	-.01	-.01	-.02	-.01	-.01	-.01	.00
Net Disposition[12]	17.29	18.87	15.02	15.71	15.66	15.82	15.86	15.79	15.75	15.72	15.77

[1] Includes lease condensate.
[2] Other Domestic prior to 1981 includes unfinished oils (net), hydrogen, and hydrocarbons not included elsewhere. After 1981, Other Domestic includes unfinished oils (net), motor gasoline blending components (net), aviation gasoline blending components (net), hydrogen, other hydrocarbons, alcohol, and synthetic crude production.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] In 1977 and later years crude oil imports include crude oil imported for the Strategic Petroleum Reserve.
[5] Net stock withdrawals for a given year, t, are defined as the change in yearend stock levels from period t-1 minus the yearend stock level from the year t. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.
[6] SPR is the Strategic Petroleum Reserve.
[7] Total supply is defined as total production plus net imports plus net stock withdrawals minus SPR additions.
[8] Jet fuel includes naphtha and kerosene type.
[9] Other products includes miscellaneous petroleum products, lubricants, waxes, unfractionated stream, plant condensate, natural gasoline, asphalt, road oil, still gas, special naphthas, and petroleum coke.
[10] Industrial refined products includes total industrial demand for petroleum as reported in Table 8.
[11] Discrepancy represents the difference between total supply and total products supplied.
[12] Net disposition is the sum of total products supplied and discrepancy.

NOTE: From 1981 onward, the product supplied data is on a new basis. From 1983 onward, the other product category is on a net basis, reclassified (petroleum products reprocessed into other categories) plus the other category of products supplied.

SOURCE: Historical data are from Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 79-99, Tables 35, 36, 37, and 45. Projected values are outputs from the Intermediate Future Forecasting System.

Historical quantities thru 1983.

Table C16. Petroleum Product Prices
(1983 Dollars per Barrel)

Sector and Fuel	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Crude Oil Prices											
World Oil Price[1]	8.35	20.69	29.35	29.91	30.53	31.14	34.12	38.18	41.78	45.64	65.89
Refinery Acquisition Cost[2]	8.50	17.93	29.35	29.91	30.53	31.14	34.12	38.18	41.78	45.64	65.89
Delivered Sector Product Prices											
Residential and Commercial											
Distillate Fuel	18.78	28.99	43.75	44.09	44.63	45.24	48.45	53.01	57.16	61.83	85.93
Kerosene	19.55	31.42	42.33	42.18	42.63	43.16	46.34	50.88	55.01	59.67	83.87
Motor Gasoline[3]	33.32	39.58	51.45	51.53	52.31	53.22	56.89	61.62	65.50	69.36	91.22
Residual Fuel	11.15	20.10	31.27	31.43	31.59	32.30	34.34	37.41	40.37	44.14	60.60
Liquefied Petroleum Gas[4]	25.27	24.17	32.05	31.95	32.01	32.40	33.46	35.17	36.98	39.33	50.32
Average[5]	19.62	27.34	40.13	40.51	40.89	41.45	44.12	47.95	51.48	55.56	76.04
Industrial											
Distillate Fuel	10.99	23.54	37.18	37.57	38.17	38.84	42.12	46.74	50.95	55.68	79.99
Kerosene	11.56	25.19	38.61	39.02	39.66	40.36	43.70	48.41	52.71	57.52	82.28
Motor Gasoline[3]	33.32	39.58	51.45	51.44	52.21	53.13	56.79	61.52	65.39	69.25	91.08
Residual Fuel	10.25	18.90	25.93	26.10	26.26	26.98	29.06	32.16	35.15	38.94	55.36
Liquefied Petroleum Gas	10.14	16.30	24.39	24.29	24.39	24.82	25.91	27.66	29.49	31.88	42.97
Petrochemical Feedstocks[6]	10.54	22.80	33.29	33.48	34.05	34.64	37.96	42.60	46.83	51.54	75.73
Asphalt & Road Oil	12.51	26.82	24.67	24.76	24.86	25.27	26.45	28.21	29.91	32.07	41.50
Petroleum Coke	11.36	24.35	7.43	7.49	7.50	7.55	7.70	7.91	8.12	8.39	9.56
Special Naphthas	9.90	21.21	32.95	33.31	33.88	34.50	37.46	41.64	45.45	49.72	71.67
Miscellaneous Petroleum Products	11.78	25.03	32.51	32.55	33.02	33.60	36.68	41.01	46.61	50.16	73.97
Average[5]	11.58	21.75	28.15	28.46	28.79	29.35	31.53	34.72	37.78	41.40	60.04
Transportation[7]											
Distillate Fuel	18.80	27.70	50.47	50.87	51.49	52.18	55.46	60.09	64.32	69.05	93.40
Aviation Gasoline	38.87	51.21	65.05	66.43	67.68	69.16	75.11	82.79	89.08	95.34	130.82
Motor Gasoline[3]	33.33	39.58	51.45	51.42	52.19	53.10	56.76	61.48	65.35	69.20	91.02
Jet Fuel[8]	11.11	24.59	37.88	38.12	38.60	39.04	42.41	47.08	51.29	55.98	79.90
Residual Fuel[9]	8.21	13.67	21.13	21.28	21.45	22.17	24.23	27.31	30.29	34.07	50.60
Liquefied Petroleum Gas	10.14	16.30	29.60	29.52	29.62	30.05	31.13	32.85	34.66	37.01	47.98
Lubricants[10]	73.36	87.47	137.58	138.29	139.40	140.62	146.46	154.71	162.23	170.66	214.02
Average[5]	28.52	35.87	49.39	49.94	50.58	51.36	54.89	59.58	63.59	67.79	90.75
Electric Utilities											
Distillate Fuel	12.73	22.69	40.43	39.11	40.99	41.24	44.24	48.87	53.43	58.25	80.73
Residual Fuel	9.99	19.17	26.93	27.01	27.39	28.13	30.19	33.53	36.57	40.38	57.08
Average[5]	10.22	19.43	27.87	27.91	27.60	28.30	30.28	33.66	37.01	40.98	58.96
Refined Petroleum Product Prices											
Distillate Fuel	16.80	26.98	45.53	45.40	46.13	46.84	50.18	54.88	59.17	63.98	88.75
Kerosene	16.77	28.75	40.33	40.84	41.40	42.02	45.27	49.89	54.10	58.82	83.25
Aviation Gasoline	38.87	51.21	65.05	66.43	67.68	69.16	75.11	82.79	89.08	95.34	130.82
Motor Gasoline[3]	33.33	39.58	51.45	51.42	52.19	53.10	56.76	61.48	65.35	69.20	91.02
Jet Fuel[8]	11.11	24.59	37.88	38.12	38.60	39.04	42.41	47.08	51.29	55.98	79.90
Residual Fuel	9.98	18.39	25.76	26.15	26.35	27.09	29.13	32.24	35.23	39.02	55.52
Liquefied Petroleum Gas	15.49	18.83	25.83	25.67	25.76	26.17	27.24	28.96	30.78	33.14	44.07
Lubricants (Transportation)[10]	73.36	87.47	137.58	138.29	139.40	140.62	146.46	154.71	162.23	170.66	214.02
Petrochemical Feedstocks[6]	10.54	22.80	33.29	33.48	34.05	34.64	37.96	42.60	46.83	51.54	75.73
Asphalt & Road Oil	12.51	26.82	24.67	24.76	24.86	25.27	26.45	28.21	29.91	32.07	41.50
Petroleum Coke	11.36	24.35	7.43	7.49	7.50	7.55	7.70	7.91	8.12	8.39	9.56
Special Naphthas	9.90	21.21	32.95	33.31	33.88	34.50	37.46	41.64	45.45	49.72	71.67
Miscellaneous Petroleum Products	11.78	25.03	32.51	32.55	33.02	33.60	36.68	41.01	46.61	50.16	73.97

[1] Average cost of crude oil imported into the United States.
[2] Refiner acquisition cost is an average of imported and domestic refiner acquisition costs.
[3] Gasoline price is an average price for all types.
[4] Residential and commercial liquefied petroleum gas price includes only a residential price due to data limitations.
[5] Weighted average price; the weights are taken from the consumption categories from Table 4 and converted to physical units.
[6] Petrochemical feedstock price includes only the price of naphthas less than 400 degrees.
[7] Transportation prices include the appropriate State road use taxes and Federal excise tax.
[8] Jet fuel price is a retail price for kerosene type jet fuel.
[9] Residual fuel price in the transportation sector is for marine bunker.
[10] Lubricant price is an average for light stocks and multiweight motor oil.

NOTE: Implicit Gross National Product Price Deflator, rebased to 1983 = 1.0, was used to convert from nominal to real dollars.

SOURCE: Historical prices are taken from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation* DOE/NBB-029)/1 (Washington, D. C., 1982) pp. 194-225, Tables B14 Through B29. Projected values are output from the Intermediate Future Forecasting System.

Historical prices thru 1981.

Table C17. Natural Gas Supply, Disposition, and Prices

(Trillion Cubic Feet per Year)
(1983 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production											
Dry Gas Production[1]	21.73	19.12	15.90	17.03	16.44	16.21	16.15	16.50	16.48	16.48	15.37
Supplemental Natural Gas[2]	.00	.00	.13	.01	.06	.05	.01	.02	.00	.02	.31
Net Imports	.96	.91	.88	.86	1.08	1.16	1.23	1.23	1.23	1.23	1.23
Net Storage Withdrawals[3]	-.42	-.15	.46	-.02	.00	.00	.00	.00	.00	.00	.00
Total Supply[4]	22.27	19.88	17.37	17.88	17.58	17.41	17.38	17.74	17.71	17.72	16.91
Consumption by Sector[5]											
Residential	4.88	4.90	4.48	4.51	4.50	4.50	4.49	4.49	4.47	4.45	4.12
Commercial[6]	2.60	2.60	2.43	2.75	2.78	2.80	2.81	2.80	2.79	2.78	2.53
Industrial	8.69	6.76	5.58	5.77	5.70	5.68	5.68	5.66	5.58	5.50	4.84
Lease & Plant Fuel[7]	1.50	1.65	.99	.83	.82	.81	.81	.83	.83	.83	.77
Transportation[8]	.73	.53	.56	.90	.90	.89	.89	.90	.90	.90	.86
Electric Utilities	3.66	3.19	2.91	2.99	3.05	2.88	2.86	3.23	3.33	3.46	4.18
Total End-Use Consumption	22.05	19.63	16.95	17.76	17.76	17.56	17.54	17.91	17.90	17.91	17.31
Discrepancy[9]	.22	.25	.42	.12	-.17	-.15	-.16	-.17	-.19	-.19	-.40
Average Wellhead Price	.45	1.31	2.60	2.60	2.71	2.79	2.93	3.14	3.45	3.83	6.70
Delivered Prices by Sectors											
Residential	2.65	3.68	5.95	6.02	6.21	6.41	6.62	6.89	7.26	7.72	11.42
Commercial[6]	1.93	3.21	5.56	5.60	5.74	5.92	6.11	6.37	6.71	7.16	10.72
Industrial	1.01	2.45	4.29	4.31	4.51	4.67	4.85	5.13	5.49	5.93	9.40
Electric Utilities	.78	2.11	3.48	3.52	3.71	3.85	4.02	4.33	4.67	5.07	8.10
Average to all Sectors[10]	1.49	2.85	4.82	4.86	5.05	5.23	5.42	5.68	6.02	6.45	9.80

[1] Net dry natural gas is defined as dry marketed production minus nonhydrocarbon gases removed.

[2] Prior to 1980 the amount of supplemental fuels included in the natural gas data cannot be determined. Supplemental natural gas includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane air mixtures.

[3] Includes net stock withdrawals for dry natural gas from underground storage, and liquefied natural gas. Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[4] Total supply is computed as dry gas production plus supplemental natural gas, net imports, and net stock withdrawals.

[5] Consumption values include small amounts of supplemental gas, which are not reported as production prior to 1980.

[6] Commercial category includes the other customer category.

[7] Lease and plant fuel natural gas represents natural gas used in the field gathering and processing plant machinery, usually totalled into the industrial sector for other consumption tables.

[8] Transportation natural gas is used to fuel the compressors in the pipeline pumping stations.

[9] Discrepancy represents natural gas lost, the net result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure, and EIA's merger of different data reporting systems which vary in scope, format, definitions, and respondent type.

[10] Weighted average price and the weights are the sectoral consumption values excluding lease and plant fuel and the transportation sector.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. The natural gas prices in this table are average prices, total revenues divided by total sales for each customer class.

SOURCE: Historical data are taken from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) and Energy Information Administration, *Natural Gas Annual*, 1982 DOE/EIA-0131(82) (Washington, D.C., 1983). Projected values are outputs from the Intermediate Future Forecasting System.
Historical prices thru 1981 and quantities thru 1983.

Table C18. Coal Supply, Disposition, and Prices

(Million Short Tons per Year)

(1983 Dollars per Short Ton)

Supply, Disposition, and Price	High Price										
	1973	1978	1983	1984	1985	1986	1987	1988	1989	1990	1995
Production[1]											
East of the Mississippi	522	487	503	553	577	588	597	609	624	642	715
West of the Mississippi	76	183	282	300	322	337	347	360	378	394	459
Total	599	670	785	853	899	925	944	969	1,003	1,036	1,174
Imports[2]	0	3	1	1	0	0	0	0	0	0	0
Exports[3]	54	41	78	79	83	86	90	94	99	105	116
Net Imports	-54	-38	-77	-78	-83	-86	-90	-94	-99	-105	-116
Net Storage Withdrawals[4]	12	11	28	-5	-6	-5	-3	-4	-6	-6	-7
Total Supply[5]	557	644	736	770	811	834	851	871	898	925	1,050
Consumption by Sector											
Residential and Commercial	11	10	9	8	7	7	7	7	7	7	6
Industrial	68	63	64	67	72	75	78	80	82	83	83
Coking Plants[6]	94	71	37	46	48	49	49	50	50	50	50
Transportation	0	0	0	0	0	0	0	0	0	0	0
Electric Utilities	389	481	626	663	679	699	712	729	754	779	905
Total End-Use Consumption	562	625	735	784	806	830	846	866	892	920	1,044
Discrepancy[7]	-5	19	1	-14	4	5	5	6	6	6	6
Average Minemouth Price[8]	17.58	31.49	28.14	29.31	29.42	29.52	29.75	29.90	30.09	30.30	31.60
Delivered Prices by Sector											
Residential and Commercial[9]	35.24	59.58	46.05	49.97	50.81	51.38	51.87	52.55	53.39	54.09	61.50
Industrial	21.20	43.68	42.54	48.82	48.56	49.61	50.52	51.48	52.54	53.50	62.30
Coking Plants[6]	37.50	74.93	59.74	64.67	64.74	65.37	65.97	66.66	67.40	68.10	73.81
Electric Utilities[10]	20.95	39.49	[11] 36.44	37.56	38.61	38.76	39.03	39.17	39.41	39.79	44.59
Average to All End-Use Sectors[12]	24.03	44.27	38.26	40.25	41.17	41.41	41.76	42.00	42.28	42.68	47.51

[1] Historical coal production includes anthracite, bituminous, and lignite. Projected coal production includes bituminous and lignite with anthracite included in bituminous.

[2] Excludes coke imports.

[3] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces and coke exports.

[4] From stocks held by end-use sectors (secondary stocks held at industrial plants, coke plants, and electric utility plants). Net stock withdrawals are computed as the yearend stock levels from the current period subtracted from the yearend stock levels from the preceding period. A minus is treated as a deletion from total supply and a plus is treated as an addition to total supply.

[5] Total supply is equivalent to production plus net imports plus net storage withdrawals.

[6] Coke plants consume metallurgical coal which is a mixture of anthracite and bituminous coal. Historically, coking plant coal price is a weighted average of anthracite and bituminous coal types. In the projections, anthracite is included in bituminous coal.

[7] Historically, discrepancy represents revisions in producers (primary) stock levels, losses, and unaccounted for. In the projected period, discrepancy represents coal used for synthetic fuel production, and errors due to conversion factors.

[8] In historical years, the average production price of coal produced at the mine. Projected prices are based on estimated cost and do not reflect market conditions.

[9] Historically, residential price is used for residential and commercial consumers. Projected residential and commercial prices do not include dealer markup.

[10] Historically, electric utility price includes anthracite, bituminous, and lignite coal purchased under long-term contracts and on the spot market. In the projections, anthracite is included in bituminous coal, with the bituminous coal price being used for anthracite coal price.

[11] The 1983 price for steam coal is a model projection and is based on contract sales. The estimated average coal price is $35.17 per short ton.

[12] Weighted average price and the weights are the sectoral consumption values.

NOTE: Metallurgical coal prices reflect a reduced level of projected demand. Other projected coal prices are based on cost estimates, and do not reflect market conditions.

NOTE: The prices have been converted from nominal to real dollars by using the implicit Gross National Product deflator rebased to 1983 equals 1.00. Projected coal prices are based on cost estimates and do not reflect market conditions.

SOURCE: Historical prices from Energy Information Administration, *State Energy Price System, Volume 1: Overview and Technical Documentation*, (DOE/NBB-0029)/1 (Washington, D.C., 1982) pp. 186-93, Tables B10, B11, B12, and B13. Historical quantities are from the Energy Information Administration, *Annual Energy Review*, 1983 DOE/EIA-0384(83) (Washington, D.C., 1984) pp. 161-169, Table 73, 74, and 75. Projected values are outputs from the Intermediate Future Forecasting System.

Historical prices thru 1981 and quantities thru 1982.

Appendix D
Forecasting Methodology and Assumptions

Appendix D
Forecasting Methodology and Assumptions

Overview

The forecasts presented in this volume result from an interaction between model representations of the key energy supply and consuming sectors. The solution is achieved within the integrating framework of the Intermediate Future Forecasting System (IFFS).

The objective of IFFS is to account for the many interactions of the different segments of the energy industry and to provide an internally consistent forecast of prices and quantities for which supply equals demand. This equilibrium solution accounts for the economic factors of supply and demand, the economic competition of fuels, and Government policies and regulations that deviate from purely economic behavior.

In the 1983 AEO, natural gas supply in IFFS was represented by another EIA analysis system, the Gas Analysis Modeling System (GAMS).[2] The two systems solved in a linked fashion produce the consistent set of forecasts presented here. Although GAMS itself is an independent representation of the gas markets, it is used as the IFFS natural gas supply module in the context of the linked IFFS/GAMS.

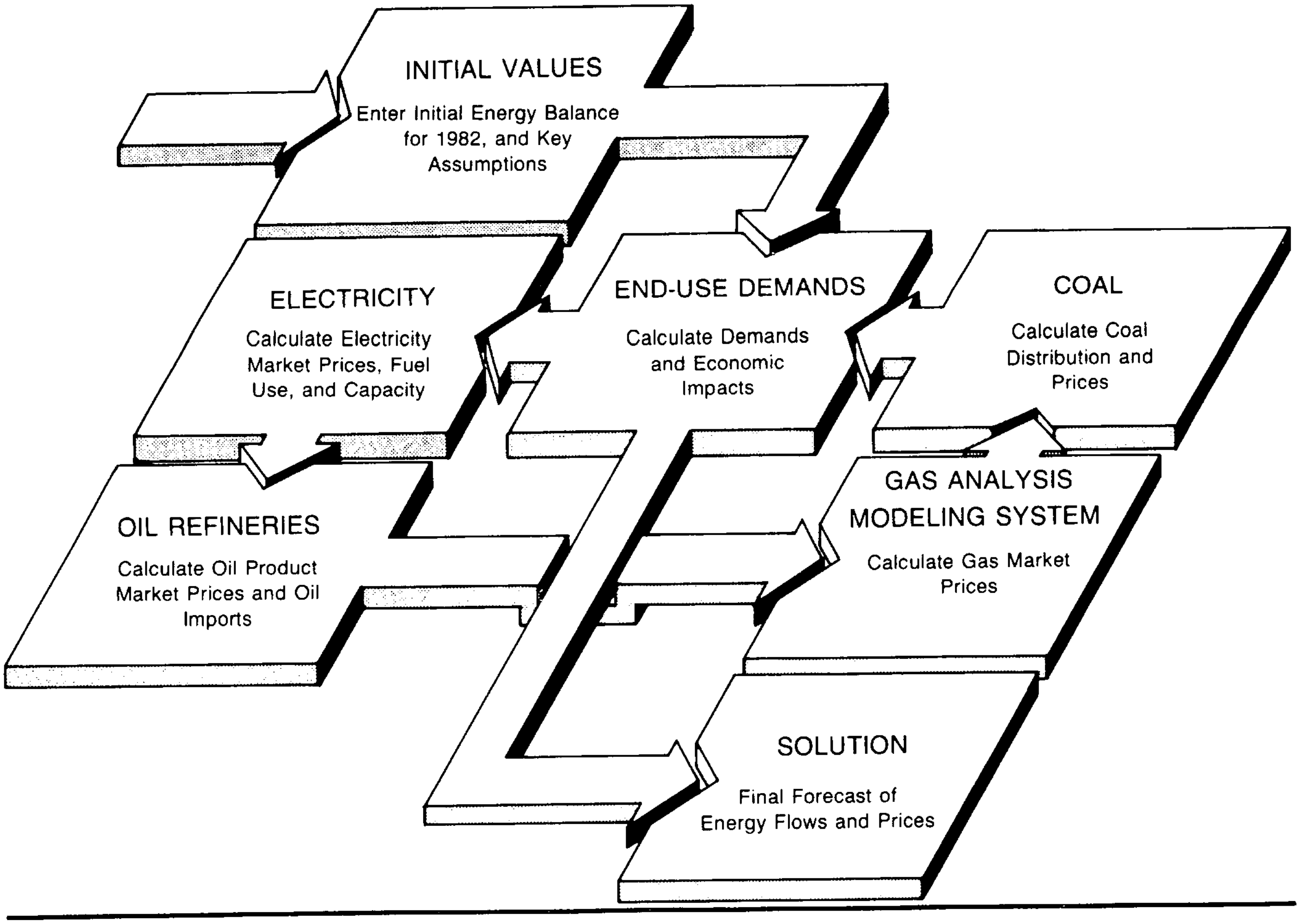
The Forecasting System: Overview

IFFS is an integrated set of modules which simulate the activities of energy supply, conversion, and demand.[1] Although IFFS includes some minor representation of new technologies, it emphasizes the major fuels, incorporating domestic supplies of and demands for oil, gas, and coal and also accounting for imports of crude oil, refined petroleum products, and natural gas. The major energy-conversion activities represented are refineries, which process crude oil into petroleum products, and electric utilities, which use fossil fuels, nuclear power, hydropower, and some new technologies to produce electricity. The IFFS projections are made for each year over a specified time horizon, through 1995 for this AEO.

Demand is estimated for natural gas, electricity, coal, motor gasoline, aviation gasoline, distillate fuel oil, residual fuel oil, jet fuel, kerosene, liquefied petroleum gases, petrochemical feedstocks, lubricants, asphalt and road oil, petroleum coke, special naphthas, and miscellaneous petroleum products. The demands are estimated by sector as follows: residential, commercial, transportation, and industrial fuel use and industrial raw materials. The demand estimates are based on fuel and electricity prices, indicators of economic activity, and regulations affecting the consumption of the various energy forms. Estimates of the consumption of various forms of energy take into account the possible substitutions among fuels. In the residential sector, for example, oil, gas, coal, electrical resistance heat, and heat pumps compete to meet home heating demands.

IFFS consists of a central integrating procedure, together with modules for energy demand by end use sector, electric utilities, oil refineries, natural gas supply, coal supply, and some degree of energy-macroeconomy interaction.[3] The current operation of the model is depicted in Figure D1. The model operates iteratively to balance supply and demand for all fuels at market clearing prices. Each of the specific fuel or energy-form modules simulates the economic forces that work within each fuel's market, while the overall integrating routine represents the linkages among the different energy markets within the economy.

Figure D1. IFFS/GAMS Calculation Flow



Although the results presented in the Annual Energy Outlook are for the United States as a whole, IFFS is a regional model. Regional disaggregation varies by module as necessary to adequately represent regional diversification present in that energy market. For example, the electricity market module is estimated at the 10-Federal-region level to account for differences in regional capacity mix and fuel availability. Regionalized activities are integrated through a transportation network, only where appropriate, primarily in the coal and natural gas supply modules.

World Crude Oil Prices

A major input to the IFFS analyses of energy is the projected world price of crude oil. This is used to define the average refiner acquisition cost of crude oil imported to the United States.

The cost of crude oil directly affects the domestic oil prices, oil consumption, and the production of both oil and natural gas. Due to the competitive nature of the fuel markets, the consumption and production of alternate fuels, such as coal, are also affected. Furthermore, the general economy is affected by the cost of energy imports and by the average price of energy, both of which, in turn, influence the demand for energy.

International energy projections are produced using EIA's Oil Market Simulation Model (OMS),[6] energy demand estimates based on the Organization for Economic Cooperation and Development (OECD) Energy Demand Model,[5] and the Non-OECD Energy Demand Model.[4] OMS simulates the Organization of Petroleum Exporting Countries (OPEC) pricing behavior and projects free world oil prices, consumption, and production.

The Individual Modules

Each module simulates either the consumption activities of end users or the operating and investment activities of firms supplying major energy forms. Operating decisions use only the current period's prices. Investment projections are made based on past and future prices. "Past" prices for a forecast year are either historical data or projections for forecast years for which an equilibrium value has already been calculated. "Future" prices are extrapolations of past prices, used within the investment and planning components. The calculations are made under the assumption that energy producers are cost minimizers. This is consistent with the conclusion that no single coal, oil, or natural gas firm represents a market force that is significant enough to affect prices measurably. Electric utilities are treated as regulated regional monopolies that attempt to minimize cost.

Macroeconomic Effects

IFFS measures the economy, using the following indexes:

- Gross National Product (GNP), a monetary measure of all goods and services sold
- Disposable Personal Income, a monetary measure of the after-tax buying power of individuals

- Manufacturing Index, a measure of industrial production
- GNP Price Deflator, an index based on GNP, that measures the rate of inflation
- Two wage-rate variables.

Other economic variables, for example, interest rates, population, housing starts, and unemployment, have assumed values which are not directly altered by the energy market but do affect the energy consumption. These variables and the baseline assumptions for the other indexes are based on values from the Data Resources, Incorporated, forecasts of the economy.[7]

Residential Sector

The residential module in IFFS computes consumption of major fuels by a series of structural algorithms that calculate the level of housing stocks, the end-use fuel shares, and the utilization (energy use per household).[8] The major fuels are electricity, natural gas, fuel oil (a combination of distillate oil and kerosene), and liquid gas. Apart from the structural algorithms, wood and coal consumption are directly calculated. Accounting equations combine the structural components to get total residential energy use for the major fuels and then add in wood and coal energy use. The module receives forecasts of fuel prices from the IFFS supply modules and income and new housing starts from the macroeconomic linkage.

The module passes final residential consumption by fuel type and Federal region to the IFFS linkage. The module operates at a level of disaggregation consisting of four end uses (space heating, water heating, air conditioning, and all others), several fuel/technology types depending upon the end use, two housing types (single family and others), four structure vintages (1980's, 1970's, 1960's, and earlier), and four Census Regions (Northeast, North Central, South, and West). When operating in IFFS, the residential module further disaggregates prices and final consumption to the 10 Federal regions.

Housing stocks are forecast based on the previous years' housing stocks, housing retirement rates, and new housing construction. New housing construction is forecast from new housing starts, then shared out by region and housing type.

Utilization (energy use per household) data by end use in the base year were estimated and the coefficients from that estimation were also used in the forecast equations. Utilization is forecast from the change in utilization in the previous year, the change in fuel prices, the change in household income, and, in the case of space heating, the change in heating degree days.

End-use fuel shares are forecast by combining fuel shares in new structures with those remaining from existing structures once conversions from oil to natural gas have been estimated. Fuel shares in new structures are forecast from the new fuel shares in the previous year, changes in fuel prices, and changes in utilization.

Conversions from oil to natural gas in existing structures are projected from a level of conversions in a base year and changes in the ratio of oil to natural gas prices from the base period.

Wood energy use is forecast from wood use in the previous year and the average price for the other fuels. It is assumed that there is an upper limit to wood energy use. The effect of wood use on the published forecasts is to reduce the consumption of alternative fuels. The coal use forecast is based on estimated coal consumption growth rates.

Commercial Sector

The commercial module in IFFS computes consumption of major fuels by of a series of structural algorithms that calculate the stock of floorspace, the end use fuel shares, and the utilization (energy use per square foot).[5] The major energy sources are electricity, natural gas, and fuel oil (a combination of distillate oil, residual oil, and kerosene). Apart from the structural algorithms, coal, liquid gas, and motor gasoline consumption are directly calculated. Accounting equations combine the structural components to get total commercial energy use for the major fuels and then add in coal, liquid gas, and motor gasoline energy use. The module receives forecasts of fuel prices from the IFFS supply modules and income and population from the macroeconomic linkage. The module passes final commercial consumption by fuel type and Federal region to the IFFS linkage.

The module operates at a level of disaggregation consisting of three end uses (space heating, air conditioning, and all others), several fuel/technology types depending upon the end use, six building types (warehouse, institution, office, hotel and motel, retail and wholesale, and miscellaneous), three structure vintages (1980's, 1974 to 1979, and earlier), and four Census Regions (Northeast, North Central, South, and West). When operating in IFFS, the commercial module further disaggregates prices and final consumption to the 10 Federal regions. Floorspace stocks are forecast based on the previous year's floorspace stocks, changes in personal disposable income, and changes in population.

Utilization (energy use per square foot) data by building type in the base year were estimated, and the coefficients from that estimation were also used in the forecasting equations. Utilization is forecast from the change in utilization in the previous year and from the change in fuel prices.

End-use fuel shares are forecast by combining fuel shares in new structures with those in existing structures. Fuel shares in new structures are set at the average level for fuel shares in the 1974-to-1979 vintage buildings and the 1973 and earlier vintage buildings. Fuel shares in existing structures are held constant over the forecast period.

Coal, liquid gas, and motor gasoline consumption are forecast based on recent consumption growth rates for these fuels.

Industrial Sector

Industrial demands for direct heat, process steam from boilers, and power, including machine drive, are forecast for each of 17 Standard Industrial Classification (SIC) manufacturing industries, aggregating chemicals with rubber and textiles with apparel. The total energy demand in each of these industries is based on real output, capital availability, labor and material prices, recession effects, current energy prices, and energy price changes.

Energy demand is allocated to region and fuel types based on a series of relationships estimated from pooled State data from 1974 to 1981, as described in A Statistical Analysis of What Drives Industrial Demand: Volume III of the PURHAPS Model Documentation, DOE/EIA-0420/3. (See DOE/EIA-0420/1 for an overview and update.) For all fuels except coal, fuel shares change from year to year depending on relative fuel prices and long-term trends. Desired coal use in any forecast year is assumed to be a fraction of potential coal use. Potential coal use in an industry depends on relative fuel prices and the scale of the industry (measured by total fossil fuel use in a State). Forecast coal use in any year is a weighted average of last year's coal use (adjusted for declines in fossil fuel use) and desired coal use, so that it takes many years to reach the desired use of coal. Data on manufacturing energy use were very extensive until 1981, after which their collection was discontinued.

Heat and power consumption outside of manufacturing are generally estimated by an input-output methodology, using DRI projections for agricultural output, construction output, and mining output together with GAMS projections for drilling activity. On-farm irrigation is assumed to grow and is projected from USDA data. Some switching from gas to electricity is also assumed with less switching than in recent historical data. Petroleum feedstocks are also projected on an input-output basis, although other minor fuels reflect price and output elasticity and trend terms, where appropriate. Most distillate fuel use, most LPG use, and most of the growth in electricity use have been in the agricultural, mining, and construction sectors. The growth of energy demand in these sectors is projected very conservatively because there is little data available, making it risky to project the apparent trend towards greater energy intensity.

Transportation Sector

The transportation sector demand for energy is calculated for each transportation mode. Passenger cars, single unit and combination trucks, piston aircraft, commercial jets, marine bunker fuel use, and liquefied petroleum gas use each have separate representations. Highway motor gasoline and distillate fuel use are calculated as the product of estimated average fleet efficiency in gallons per mile and vehicle-miles traveled. Fleet efficiency is estimated to shift over time in response to changes in the real price of motor gasoline. Annual vehicle miles of travel are estimated to adjust over time to the fuel cost of driving a mile and to the level of economic activity. Total vehicle-miles are disaggregated into diesel and motor gasoline shares based on estimates of trends in motor gasoline costs per mile of travel. Lubricant requirement forecasts are based on estimates of total vehicle miles of travel.

Commercial jet fuel use is calculated based on estimates of airline activity and aircraft fuel efficiency. Estimates of airline activity are based on trends in disposable personal income and airline ticket prices. Ticket prices, in turn, are influenced by trends in the price of jet fuel and aircraft fuel efficiency. Jet aircraft fuel efficiency is estimated based on historical trends.

Estimates of fuel use in the remaining transportation subsectors (rail, marine, LPG, off-highway diesel use) do not explicitly consider capital stock effects on energy-use efficiency. These estimates are based on historical trends, the level of economic activity, and fuel prices.

Electric Utilities

The electricity market module estimates necessary capital expansion plans, schedules available capacity to satisfy demand, and simulates regulatory behavior in pricing electricity as a function of operating costs and capital accounts. The electric utility industry is a fuel consumer as well as producer, converting about 35 percent of total primary energy input to electricity. Electricity is generated from a variety of plant types and fuel inputs: coal-, gas-, or oil-fired steam; gas or oil combined cycle; gas or oil turbines; nuclear; and hydroelectric.

Electricity generation is equal to the end-use demand plus the transmission and distribution losses, which typically average 9 percent of generation. The utilization of the existing generating capacity depends on the relative generation costs (for fuel plus other operation and maintenance), outage rates, and the level of demand. The selection of the capacity dispatched (operated) is made on the basis of generation costs. Thus, the plants having the lowest fuel costs, such as coal-fired steam and nuclear, operate almost continuously and their usage is limited only by projected forced outages and scheduled maintenance. Conversely, oil- and gas-fired turbines have the highest operating costs and are typically dispatched only to satisfy the peak load levels which occur relatively infrequently. Fuel consumption is equal to the energy content of the electricity generated by the fuel divided by its generation efficiency, that is, the ratio of energy output to input for generating plants using the fuel.

The capacity available for dispatch in a forecast year consists of plants that now exist plus net capacity additions completed by that year. Two types of capacity additions are estimated. The first type consists of units currently in the planning or construction stages and is referred to as "pipeline" capacity. The second type involves "new" capacity, which is calculated as those plants necessary--in addition to the existing and pipeline plants--to meet projected demands. For each unit of new capacity started in a given forecast year, the corresponding completion date is computed, based on exogenous construction lead times. The capacity planning process uses recent historical data to estimate growth rates for electricity demand, capital costs, and fuel costs. For each allowable type of new generating capacity, these growth rates are used to project the demand and costs at the end of the associated planning horizon. The optimal mix of capacity is that which has the lowest annualized system cost (capital plus generation). Once the allocation and construction of generating capacity are determined, the supply price is computed. Under the current regulatory structure, the supply price is based on the average rather than the marginal cost of electricity generation.

The average cost is defined as the total annual cost divided by the total generation. Total cost has 3 major components--capital, fuel, and operating and maintenance (O&M). The total capital cost includes a capital charge on the undepreciated portion of existing plants and a capital charge for Construction Work in Progress (CWIP), where allowed. The CWIP component is computed using prespecified capital expenditure profiles, which are also used to determine interest charges where CWIP is not permitted. For each input fuel, the total fuel cost is the product of the utility demand for that fuel and its cost. The O&M component is the product of generation and per-unit O&M costs summed over each type of generating capacity. Once the average supply price is determined, it is then adjusted for distribution costs to obtain end-use prices for the residential, commercial, industrial, and transportation sectors.

Petroleum Refining

The oil module contains a representation of refineries and refined product demand. The demands for petroleum products are the consumption levels for the end-use sectors evaluated at the refined product prices, plus the consumption by electric utilities. Oil refineries produce a slate of finished products, with varying yield patterns; and the prices for the refined products are determined, in part, by the cost of refining the desired product mix.

The costs of refined products depend on the world price of oil, the costs of refining the product mix, and transportation and distribution costs. The refinery representation in IFFS accounts for the flexibility of the refining industry to produce the products demanded, the costs of refinery operations, including the refinery's own fuel needs, the imports of both crude oil and finished petroleum products, the capacity of domestic refineries, and the end-use prices of products.

The refinery model underlying the IFFS refinery computations is is the Refinery and Petrochemical Modeling System of Bonner and Moore, Management Consultants, Inc.,[10] This system was solved for a variety of product demand slates and downstream unit capacities, in order to derive parameters defining the costs of refining each product as a function of the slate of demands.

The refinery gate prices computed by IFFS are a model construct, not corresponding to wholesale prices at the refinery gate. These relative prices reflect the world crude oil price, the composition of the slate, and refinery capacity. Region-specific and end-use-specific markups are added to these refinery gate prices to get retail prices. Markups are computed as the difference between the refinery gate price and the historical retail price in 1983, where the Petroleum Marketing Monthly was the source of retail prices and these markups remain constant in real terms through the forecast period.

This methodology was used for the major petroleum products, gasoline, distillate fuel, residual fuel up to 1 percent sulfur, residual fuel over 1 percent sulfur, jet fuel, liquefied petroleum gas, and petrochemical feedstocks. Prices for minor fuels, aviation gasoline, kerosene, lubricants, petroleum coke, asphalt, and special naphthas, are projected as functions of certain major fuel prices, based on data in the Energy Price and Expenditure Data Report, 1970-1980, (DOE/EIA-0376, July, 1983).

The quantity of imported crude oil is calculated as the difference between the total crude oil input to refineries (determined by the refinery module) and the domestic crude production. Quantities of imported products are estimated as their historical shares of the domestic demand by region.

Oil and Natural Gas Production

The domestic production of crude oil is computed in conjunction with the production of natural gas, due to the nature of their production process. Oil and gas exploration and development are performed by the same industry, using the same equipment. Further, oil and gas are frequently found in the same geological formations, sometimes with the gas in contact with or dissolved in the oil; such gas is called associated or dissolved gas. Therefore, the level of activity for the exploration, development, and production of one fuel is highly likely to affect the activity in the discovery and production of the other.

The domestic oil and gas supply projections are based upon estimates of certain categories of production and an EIA analysis system external to IFFS,[11] the Production of Lower-48 Oil and Gas (PROLOG) model.[12] The projections of North Slope Alaskan oil and South Alaskan oil are provided by the Alaska Department of Revenue, Petroleum Production Revenue Forecast. Projections for Outer Continental Shelf production, enhanced oil recovery, shale, and synthetic crude production were estimated within EIA.

The oil production forecasts from the offshore areas of the Lower 48 states reflect a generally stable level of production. Anticipated declines in production from the Gulf of Mexico are offset by expected production increases in the offshore Pacific. The forecasts are not based on an explicit representation of recent lease sales or announced leasing plans. Given the unprecedented amounts of offshore acreage made available under the present Administration, it is not clear how the behavioral parameters of the industry will be affected.

Solving the PROLOG model produces estimates of reserve additions of oil and gas and of the production of oil from both existing and new reserves. The PROLOG estimates of crude oil production constitute exogenous inputs to IFFS. Natural gas liquids (NGL) production is computed as a function of the marketed natural gas production, with the ratio of NGL to marketed gas production computed from historical data.

Natural gas supply, consumption, and pricing are complicated by the nature of the market and by regulatory mechanisms. Briefly stated, most natural gas is gathered from a large number of producers, transmitted by long-distance pipelines, distributed by companies that are regional monopolists, and consumed by a wide variety of end users.

The natural gas market is regulated by the provisions of the Natural Gas Policy Act of 1978 (NGPA). The NGPA established a pricing structure for gas at the wellhead, placing most gas under price ceilings based on the geology, distance from other wells, location, depth, and existing contractual arrangements.

The gas supply representation, the Gas Analysis Modeling System (GAMS), is linked to IFFS. GAMS takes into account all major factors that influence the natural gas market: the availability of drilling rigs, the cost of capital, the bidding system for new reserves, the pipeline distribution system, Federal laws and regulations, projected demand, the impacts of current contract provisions, the possibility of fuel switching, etc.

GAMS contains representations of four groups that interact with one another in the natural gas market:

- Producers: individuals and companies that search for new supplies of natural gas and sell gas to pipeline companies or direct end users.

- Pipeline companies: firms that purchase gas at the wellhead and transport it for resale to other pipeline companies, to distributors, or directly to consumers.

- Distributors: privately- or publicly-owned firms that purchase gas from pipeline companies and sell it to end users.

- Consumers: commercial establishments, industrial firms, electric utilities, and residential users that consume natural gas for space and process heat, often as boiler fuel to raise steam, and chemical feedstock.

Recognition of the interaction of these four groups is not new, but the degree of detail to which GAMS analyzes their interaction is.

To determine the overall volume of gas available for production from conventional sources, GAMS uses reserve addition forecasts from the PROLOG model. Within both of these systems, drilling activity is subdivided into exploratory and developmental categories, with the latter further subdivided by the type of reserve (oil or gas) to be developed. The amount of exploration (which adds to new reserves) and development activities are estimated based on historical growth patterns, expected profitability, and capital resources. Expected profitability is, in turn, represented by the present value of project revenues, computed using a discounted cash flow analysis, net of the expenditures required for drilling and exploration. Profitability, current capital resources, and the cost of money (interest rates) are then linked to calculate how successfully one firm could compete with other firms for the available drilling rigs and associated equipment. The availability of equipment is used to estimate how much drilling activity can be undertaken.

Similarly, detailed interactions are represented for each of the other three groups and subgroups in the natural gas market and for the U.S. economy as a whole. Unlike earlier models, GAMS recognizes that there are two distinct but loosely coupled markets for natural gas: a long-term market, represented by pipeline companies bidding and contracting for new reserves on the basis of existing supply commitments and projected sales; and a short-term market, in which production from reserves is sold, delivered, and consumed. Total natural gas supply is then estimated from imports, spot-market purchases, and reserves under long-term contract.

End-use prices are computed by GAMS for each end-use sector, region, and year, reflecting all transmission and local distribution costs and the availability to the various regions of quantities of both newly discovered and older, less expensive gas.

GAMS itself is an equilibrium model of gas supplies and demands; however, for this AEO it is used as a gas supply module of IFFS. By operating in this fashion, the two systems can converge to a single equilibrium solution of the integrated energy markets.

Coal

The coal module in IFFS is a version of the Coal Supply and Transportation Model (CSTM).[13] Each end-use demand specified includes an allowable range of Btu and sulfur levels that is satisfied by solving for the cost-minimizing array of shipments from the coal-producing areas via the transportation network. The supply component is derived from the Resource Allocation and Mine Costing (RAMC) model,[14] which uses the quantity of available reserves and the cost of mining (through the use of nine model mines) to calculate the amount of coal available at a given price for both underground- and surface-mined coal. The Coal Supply and Transportation Model (CSTM)[15] uses these prices to construct piecewise linear functions that specify the potential levels of coal produced in each region over a range of price levels. The transportation component determines a freight rate for each network link that increases as a function of the volume of coal shipped across the links. Separate cost functions are provided for rail links, barge links, and collier links, as well as for the costs of transferring coal between different transportation modes. Other factors that affect transportation rates include distance traveled, terrain, congestion, competition, fuel costs, and capital improvement requirements.

To meet each end use demand, the CSTM determines the least-cost combination of coal supply source and transportation route. When increased volume on a route or increased production in a supply region leads to higher delivered prices, the CSTM selects alternate routes or sources of supply. In each demand region, coal is shifted from high-cost to low-cost routes and sources in determining a price equilibrium. Selection of new routes and sources and shifting of coal from high-cost to low-cost routes and sources continues until the delivered coal prices of the different coal supply sources and transportation routes that provide coal to each demand region have been minimized.

Demands in the CSTM are specified by giving the required total heat content in Btu, the different types of coal that can be used to satisfy the demand, and the type of scrubbing technology required to reduce sulfur emissions. The CSTM finds the coal that can satisfy each demand at the least cost, taking into consideration the costs of production, transportation, and scrubbing to remove sulfur emissions. Each demand specified may be met by a mix of coals of different types from different supply regions because the demand is given only in terms of the total Btu required and the different types of coal that can be used. Coal demands under existing contracts are represented separately.

The CSTM represents 32 coal supply regions, 48 coal demand regions (44 domestic and 4 overseas), 767 transportation links, and 60 different types of coal (5 Btu and 6 sulfur categories from both underground and surface sources).

Consistency of Data with Other EIA Publications

The 1983 Annual Energy Outlook (AEO) consumption levels for the years 1980 through 1984 have been calibrated to be consistent with other EIA publications. The purpose of this calibration ("benchmarking") is to ensure that the most recent available estimation data are taken into account in the projections. Many of the models begin forecasting in 1980 and can therefore benefit from more recent data.

The demand models are calibrated to actual "State Energy Data System" (SEDS) consumption data for 1980 and 1981, available by fuel, sector, and region. The models are also calibrated to preliminary SEDS consumption data for 1982, which are available by fuel and sector. Finally, the models are also calibrated to the annual data published in the 1983 Annual Energy Review and to the projections published in the February 1984 Short-Term Energy Outlook (STEO) for 1983 and 1984, which are available by most fuel categories with minimal sector detail. The purpose of this last calibration is to capture the effects of any recent conservation and to benefit from the special characteristics of a specifically short-term model. The following discussion describes the methodology that is used in each case to calibrate the models.

SEDS consumption data are available in virtually full detail by fuel, sector, and region for the years 1980 and 1981. A data base has been created with this detail and is used by each of the IFFS modules for calibration. The calibration is implemented in different ways by the various models, but falls into one of two patterns. In the first case, the model equations are solved for the "intercept," or "constant," terms given the level of consumption. This modified intercept, or constant term, is then one of the coefficients used in subsequent model projections. This procedure ensures that the models solve for the actual consumption levels in 1980 and 1981 and continue on a path through those levels. In the second case, for 1980 and 1981, the model results are compared to the actual data. Adjustment factors are created by dividing the actual data by the model results, providing the actual level of consumption for those years. Model projections beyond 1981 are subsequently multiplied by the adjustment factors to ensure that the models continue on a path through the 1980 and 1981 levels as in the first case.

The preliminary SEDS consumption data by fuel and sector for 1982 have been included in the data base along with the 1980 and 1981 data. Regional detail has been estimated by applying the 1981 regional shares to the 1982 national data. Once the data base has been created, the data for 1982 are used by the models for calibration in the same manner as described above for 1980 and 1981.

The STEO publishes projections for 6 quarters. The February, 1984, STEO includes a full-year projection for 1984. The IFFS modules calibrate to these STEO projections. The projections published are not regional, are generally not sectoral, and have less fuel detail than those in IFFS; however, the greater fuel detail used in making the published STEO projections is used in the IFFS/STEO calibration procedure. Full sectoral and regional detail are not used for STEO; therefore, IFFS projections are probably the best guide for their relative magnitudes.

A subroutine in IFFS compares the aggregate estimates by fuel type to the STEO projections in 1984. Adjustment factors by fuel type are created by dividing the STEO projections by the IFFS projections, resulting in the STEO forecasts of consumption. The factors are then passed to each of the consumption modules where the disaggregated module results are multiplied by the factors. This procedure ensures two things: first, the consumption totals from the IFFS modules are consistent with the STEO consumption totals in 1984, and, second, the relative consumption projections for each of the modules by sector and region are preserved. The adjustment factors for 1984 are subsequently used to continue to adjust the projected consumption levels for each of the IFFS modules beyond 1984. This is done to assure that the model continues on a path consistent with the 1984 STEO projections. This procedure captures the recent consumption or conservation trends that are projected in STEO.

Detailed Assumptions

Residential Sector Assumptions

The residential module is calibrated so that the consumption totals for all the fuels in 1980 and 1981 equal the levels reported in the State Energy Data Report 1960 through 1981 (SEDS). The distribution of consumption among the 4 Census Regions and the 10 Federal Regions for sharing of prices and consumption in the forecasts are assumed to equal those in SEDS in 1981. The model is calibrated to preliminary SEDS values in 1982.

Distillate oil and kerosene are combined and modeled as fuel oil. Their shares in each year are based on their shares in 1981. Coal consumption is based on a growth rate from recent SEDS data. Wood consumption is based on a logit equation with an upper limit on use assumed to be no more than 50 percent above the highest wood use in the last 10 years as detailed in EIA's Estimates of U.S. Wood Energy Consumption from 1949 to 1971.

Residential electricity, natural gas, fuel oil, and liquid gas consumption are calculated using a structural equation system consisting of forecasts of housing stock, fuel shares, and average utilization. New housing is assumed to be allocated to Census Regions and housing types according to the "Annual Housing Survey: 1981" (AHS). Retirement rates for the housing stock are derived from "Energy Capital in the U.S. Economy." The coefficients for fuel shares in new structures for space heating are assumed to equal one. This provides a one-to-one response between the changes in costs and the changes in the logit form for fuel shares. Air conditioning fuel shares in new structures are based on growth rates assumed from observation of data on recent behavior. Fuel shares in new structures for water heating and other uses are assumed to equal those in the previous year. Fuel shares for space heating in existing structures are assumed to change based on an equation that models conversions from fuel oil to natural gas. Initial data for new fuel shares are from "Characteristics of New Housing: 1981" (CNH), and initial data for existing fuel shares are from a combination of the "Residential Energy Consumption Survey (1981)" (RECS)[16] and the 1981 AHS. Long-term utilization for each of the major fuels is estimated from RECS data. The short-term utilization elasticity is assumed to be 20 percent of the estimated long-term elasticity for each of the end uses. The elasticity for fuel oil utilization is assumed to equal that for natural gas. Electric heat pump use is assumed to be a proportion of all electric space heat that is based on the 1981 CNH. The coefficient of performance (ratio of energy delivered to electric energy used) for these heat pumps is assumed to be 1.4 in the base year.

Commercial Sector Assumptions

The commercial module is calibrated so that the consumption totals for all the fuels in 1980 and 1981 equal the levels reported in the State Energy Data Report 1960 Through 1981 (SEDS). The distribution of consumption among the 4 Census Regions and the 10 Federal Regions for sharing of prices and consumption in the forecasts are assumed to equal those in SEDS in 1981. The model is calibrated to preliminary SEDS values in 1982.

Distillate oil, residual oil, and kerosene consumption are combined and modeled together as fuel oil. Their shares in each forecast year are based on their shares in 1981. Coal, liquid gas, and motor gasoline consumption estimates are based on growth rates from recent SEDS data.

Electricity, natural gas, and fuel oil use are calculated using a structural system consisting of forecasts of commercial floorspace, fuel shares, and average utilization. The commercial floorspace stock is based on data from the "Nonresidential Buildings Energy Consumption Survey" (NBECS). The retirement rate for existing floorspace is assumed to be 0.6 percent annually. Fuel choices in newly constructed floorspace are assumed to equal an average of those in the 1974 to 1980 vintage structures and those in vintages before 1974 from NBECS. Fuel choices in existing floorspace are assumed not to change during the forecast period. Long-term utilization for each of the major fuels is estimated from NBECS data. The short-term utilization elasticity is assumed to be about 3.5 percent of the estimated long-term elasticity for electricity and natural gas, and about 8 percent of that for fuel oil.

Industrial Sector Assumptions[17]

Oil/Natural Gas Use. After 1982, the trend of switching from oil to natural gas use is assumed to end, although competition based on price continues. It is assumed that the historic trend was based on gas service expansion, environmental pressures, and fear of oil shortages, which result in extensive dual-fuel capability.

A 1-percent change in the price of natural gas relative to oil leads to a 1-percent change in the ratio of oil use to gas use for heat and power in manufacturing nationwide; the response is about twice that for some industries in specific States. The model used for estimating industrial responses to shifts in prices is equivalent to the Weibull distribution, which assumes that each firm uses the fuel that is cheapest for it, but that different firms face different markups and penalties in using different fuels. Because the model is fitted to State-level historical data, in each industry, the effects of diversity in smoothing out price responses are measured rather than allowed.

Fossil Fuel/Electricity Use. A 1-percent change in the price of fossil fuel relative to electricity leads to about a 0.2 percent change in the ratio of electricity to fossil fuel use for heat and power in manufacturing in specific industries in specific States. The trend from fossil fuel to electricity use is assumed to continue at the historic rate in manufacturing. In agriculture, construction, and mining, electrification is projected to proceed at a lower rate than that suggested by recent EIA data.

Coal. The coal equation is entirely econometric, although technical assumptions were used in developing key dependent variables. The potential use for coal was assumed to be about 20 to 30 percent larger than the boiler fuel share in 1979, the most recent year of data for boilers, plus all fossil fuel use in cement and lime kilns. Based on empirical results, actual coal use moves only 5 to 15 percent of the way towards desired coal use in any year. This lag is at least as important as prices in determining near-term coal use.

Overall Energy Use. Although total energy use varies directly with economic activity, a recession (a decrease in real output relative to the highest output in any prior year) increases energy use per unit output within specific industries. The long-term energy intensity of industrial activity depends on the ratio between energy prices and other costs. However, because in some cases capital stock must be replaced before energy can be saved, changes in energy prices do not change energy intensity immediately. Changes in energy use are estimated on the basis of an average of previous price changes, where the average is rolled over at the rate of capital depreciation (10 percent per year). Energy intensity is the result of these two effects (recession and rolled-over price changes), as well as current prices, although historical data indicate that current energy prices have little impact. The long-term elasticity of total energy use (for heat and power in manufacturing) with respect to energy cost is about -.2 to -.3; other energy use in industry is not elastic and accounts for half of the energy in Btu.

Transportation Sector Assumptions

Highway Fuel Use. Fuel consumption calculations are based on analyses of Federal Highway Administration data and estimates of average fleet efficiency. It is assumed that existing Corporate Average Fuel Efficiency standards continue in effect.

Non-Highway Fuel Use. Total jet fuel consumption is the sum of commercial jet fuel consumption plus general aviation and military jet fuel consumption. These figures are based on Federal Aviation Administration and EIA forecasts.

In estimating commercial jet fuel use it is assumed that airline activity is represented by revenue passenger miles for all domestic flights plus one-half of revenue passenger miles for international flights.

It is assumed that commercial cargo jet fuel use is 8.5 percent of commercial passenger jet fuel use. The commercial jet load factor is assumed to be constant at 0.63 over the projection period.

Transportation electricity consumption is held fixed at its 1981 level during the forecast period.

Electric Utility Assumptions

Capacity Factors. The utilization rates for existing nuclear and fossil-fired steam plants are based on actual data in historical years through 1982. The utilization rates are assumed to grow linearly from 55 percent in 1982 to 62 percent in 1990 for nuclear plants and from 49 percent to 62 percent in 1986 for coal plants and remain constant thereafter. For new coal plants, the utilization rate is assumed to be 55 percent during the first year of operation and 65 percent thereafter. New nuclear plants are assumed to operate at a 41-percent capacity factor for the first fuel cycle, which is typically about 2 years, and at 62 percent thereafter.

Nuclear Fuel. It is assumed that adequate supplies of uranium will exist throughout the forecast period and that the cost in constant dollars will remain unchanged.

Plant Efficiencies. In each forecast year, the plant efficiencies are assumed to be the average of the actual 1980 through 1982 figures. The efficiencies for new plants are given in Table D1. Estimates for coal-fired plants were derived from EIA's "Regionalized Capital and Operation and Maintenance Cost Estimates for Emission Control Equipment for new Coal-Fired Power plants," May 1982. Nuclear and hydroelectric efficiencies are obtained from EIA's December 1983 Monthly Energy Review. All other efficiencies were taken from EIA's Data Notebook Generating Technology Assessment, R-035-DOE-80, January 1980.

Table D1. Efficiencies for New Electric Power Plants
(Percent)

Source	Percent
Noncoal Fossil-Fired Steam	35
Coal-Fired Steam	
Bituminous--All Sulfur Levels	35
Subbituminous-Low Sulfur	34
Subbituminous--Medium Sultur	33
Lignite--Low Sulfur	33
Lignite--Medium Sulfur	34
Combined Cycle	36
Turbines	24
Nuclear Power	31
Hydroelectric Power	33

Environmental Standards. Existing coal-fired plants are assumed to burn the same coal types as they did in 1982, which implies that the plants will meet or exceed the State Implementation Plan (SIP) standards. Coal-fired plants currently under construction which were licensed before September 1978 must satisfy the New Source Performance Standards (NSPS). If the license for a new coal-fired plant was obtained after September 1978, the plant must satisfy the Revised New Source Performance Standards (RNSPS).

Plant Capacities. The existing and "pipeline" capacity (capacity currently under construction) levels are obtained from EIA's Generating Unit Reference File (GURF) except for nuclear and existing hydroelectric plants. Hydroelectric plants are from FERC's Hydroelectric Power Resources of the United States-Developed and Undeveloped, FERC-0070, January 1, 1980. Existing nuclear capacities are obtained from U.S. Commercial Nuclear Power, DOE/EIA-0314, March 1982. Projected nuclear capacity additions are produced from information in Form EIA-254: "Quarterly Progress Report on the Status of Reactor Construction" and modified by a reactor-by-reactor analysis of anticipated commercial operation dates.

New Plant Construction. It is assumed that construction and licensing, which is specified on a plant-by-plant basis, typically takes 13 years for a nuclear plant, 8 years for fossil-fired steam and combined-cycle plants, 2 years for turbines, and 5 years for hydroelectric plants. No new construction, except for plants currently planned or under construction, is assumed for single-fired, oil or gas steam or turbines or for nuclear and hydroelectric capacity.

Capital Costs. Capital costs vary significantly according to the location of the new plant. Table D2 contains the capital costs of new plants built in Federal Region 5, which is considered representative of the national average. The estimates for capital costs for new plants in 1983 dollars per kilowatt are based on plants constructed "overnight" and do not include any allowance for funds used during construction (AFUDC). Estimates for coal-fired steam plants were taken from EIA's CONCEPT-5 model. Nuclear capital costs were obtained from EIA's Quarterly Progress Report on the Status of Reactor Construction. All other figures were based on data taken from EIA's Data Notebook Generating Technology Assessment, R-035-DOE-80, January 1980. Note that the costs for lignite plants are from Federal Region 6, because Region 5 does not use lignite.

Table D2. Capital Costs by Type of Generating Capacity, Federal Region 5 (1983 Dollars per Kilowatt)

Source	
Oil/Gas Steam	628
Coal-fired Steam	
Bituminous--Low Sulfur	881
Bituminous--Medium Sulfur	873
Bituminuous--High Sulfur	915
Subbituminous--Low Sulfur	875
Subbituminous--Medium Sulfur	894
Lignite--Low Sulfur	909
Lignite--Medium Sulfur	928
Combined Cycle--Gas	434
Turbines--Gas	212
Turbines--Distillate	228
Nuclear Power	1244
Hydroelectric Power	1256

Construction Profiles. The annual expenditures (as a percentage of the total construction costs) for new nuclear and coal plants, which account for almost all of the capacity additions during the forecast period, are described in Table D3. The capital expenditure profiles are extracted from EIA's CONCEPT-5 model.[18] The nuclear profiles vary by unit based on differences in lead times for construction.

Table D3. Annual Shares of Plant Construction Expenditures, Region 5 (Percent)

	Year Before Commercial Operation													
Plant Type	15	14	13	12	11	10	9	8	7	6	5	4	3	2
Nuclear														
10-Yr. Lead Time	_	_	_	_	_	0.2	2.5	9.7	20.2	26.9	23.5	12.8	3.7	0.4
12-Yr. Lead Time	_	_	_	0.1	1.2	5.0	11.6	18.9	22.7	20.3	13.1	5.6	1.4	0.1
14-Yr. Lead Time	_	0.0	0.7	2.8	6.9	12.3	17.3	19.6	17.7	12.7	6.8	2.6	0.6	0.1
15-Yr. Lead Time	0.0	0.5	2.1	5.4	9.9	14.6	17.8	17.9	14.8	9.8	5.0	1.8	0.5	0.0
Coal	_	_	_	_	_	_	_	0.4	4.3	9.7	29.1	27.5	19.1	12.0

Cost of Finance. Table D4 presents the assumed nominal cost of finance for debt, preferred equity, and common equity.[19] Table D5 describes the assumed financial structure of electric utilities for 1980 to 1995. The assumed financial structure approaches the 1985 target value during 1980 to 1984 and remains constant from 1985 to 1995. The figures in both tables are for Federal Region 5, which is considered to be representative of the national averages.

Table D4. Nominal Cost of Capital Components
(Percent)

	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995
Debt	12.3	12.2	12.0	12.0	11.8	11.5	11.1	10.8	10.9	10.9	10.8	10.6	10.3
Preferred ...	12.3	12.2	12.0	12.0	11.8	11.5	11.1	10.8	10.9	10.9	10.8	10.6	10.3
Common	15.4	15.2	15.0	14.9	14.7	14.5	14.3	14.1	14.0	13.9	13.8	13.7	13.5

Table D5. Electric Utility Financial Structure, Federal Region 5
(Percent)

	1983	1984	1985	1986	1987	1988	1989	1990/1995
Debt	52.5	52.7	53.0	53.0	53.0	53.0	53.0	53.0
Preferred	12.0	12.0	12.0	12.0	12.1	2.0	12.0	12.0
Common	35.5	35.2	35.0	35.0	35.0	35.0	35.0	35.0

Interregional and International Electricity Trade

Transfers of electricity among utilities are used to facilitate operations. Net transfers are adjusted for transmission losses by using an assumed loss factor of 9 percent. Assumptions with respect to net imports of electricity from Canada are based on data developed in the EIA report U.S.-Canadian Electricity Trade, DOE/EIA-0365, November 1982 (Table D6). Interregional transfers of domestically produced power are determined exogenously to reflect the need to balance domestic production and sales to ultimate consumers. In the base period, these transfers are assumed to provide sufficient power to allow each region to satisfy demand. Sending and receiving regions are identified on the basis of the established transmission grid. Changes in interregional transfers are projected to reflect scheduled plans.

Table D6. Assumptions on Net Interregional Transfers of Electricity, 1990
(Trillion Btu)

Source: Destination	Canada	1	2	3	4	5	6	7	8	9	10
1	29,69	11.10	15.40								
2	49.64			79.80							
3	3.41										
4							8.12	3.41			
5	26.61			61.98	14.66					29.00	
6								3.75			
7						.30				6.60	
8	9.55										
9	5.46						27.34				81.06
10	3.07									158.20	

Oil and Natural Gas Production Assumptions

World Oil Price. Table 2 gives the historical and projected average landed prices of imported crude as estimated using EIA's Oil Market Simulation (OMS) model.

Crude Oil Windfall Profit Tax Act. This law includes a definition for each category of oil, a base price, and a tax rate to be applied to the difference between the base price and the market price. The treatment given each of the crude oil categories is as follows:

- Old oil: The quantity of old oil produced is assumed to be unaffected by the tax.

- Newly discovered oil, incremental tertiary, and heavy oil:
  - Rate: 30 percent in 1981, declining to 15 percent in 1985 and thereafter.
  - Base: $16.55 per barrel plus inflation since second quarter of 1979, plus 2 percent real increase per year.
  - Capital decisions are based on the return adjusted for the windfall profit tax on new oil.

- Alaskan oil: Sadlerochit formation:
  - Rate: 70 percent
  - Base: $12.81 plus inflation since second quarter of 1979
  - All other Alaskan oil discovered after 1979 is exempt from the windfall profit tax.

Wellhead Prices for Natural Gas. Wellhead prices for gas produced in 1980 were obtained from the Form EIA-758 ("Natural Gas Producer/Pipeline Contract Report") and Purchased Gas Adjustment data. These data provided the prices for 1981 through 1983 for the interstate pipelines for which they were available. Prices for some pipeline system NGPA categories were adjusted based on market out actions detailed in "Gas Industry Actions by Fuel Purchasers to Reduce Gas Costs" and published by the American Gas Association.

Contract Provisions for Natural Gas. Data from Natural Gas Pipeline/Producer Contracts: A Preliminary Analysis, (DOE/EIA-0312), and the Form EIA-758 were used to provide the distribution of contract escalation clauses for existing contracts or contracts in effect prior to 1981.

Contracts in effect in 1980 for gas for which the price is curently controlled are divided between those with clauses specifying "definite only" pricing and those with clauses specifying highest allowed regulated rates, based on data from Form EIA-758. Prices for "definite only" came from Form EIA-758. Gas priced under a highest allowed regulated rate receives the NGPA ceiling price until deregulation.

New contracts, post-1980, for gas under pricing contracts are given the lower of either the highest allowed regulated rate (and receive the NGPA ceiling price until decontrol) or the market-clearing price for new contracts. All new contracts for gas not under pricing controls receive the market clearing price.

When gas under existing contracts is decontrolled, most clauses with highest allowed regulated rates provide for alternative pricing clauses upon deregulation. Information on deregulation pricing is taken from the EIA-758, and the contracts are divided into five categories: oil parity clauses, most-favored-nation clauses with and without market-out provisions, all other deregulation clauses, highest allowed regulated rate with no deregulation clauses, and "definite only" pricing.

Upon decontrol, gas covered under contracts with oil parity clauses with no market-out clause are assumed to receive a price that escalates to 110 percent of the price of distillate fuel oil. Gas sold subject to most-favored-Nation clauses with no market-out provisions receives the oil-tied price with a 1-year lag. All other deregulated gas receives, by assumption, the new contracts price in the first year, with the price adjusted each year according to the movement in the new contracts price each year.

This analysis assumed that all contracts signed in or after 1981 include market-out provisions. Under a market-out clause a pipeline can refuse to take delivery of gas it cannot market, but the producer has the right to seek alternate buyers. This analysis assumed that gas covered by market-out clauses would be priced at the market price for new gas supplies; for, if the pipeline offered lower than market prices, the producer would sell the gas elsewhere; while if the producer demanded higher than market prices, the pipeline could release the gas and obtain alternate supplies.

All wellhead prices are adjusted to calibrate to national level totals and Purchased Gas Adjustment filings.

Take-or-Pay. Take-or-pay requirements for any new contract (post-1980) are assumed to be 75 percent of the deliverability. For contracts in effect in 1980, pipeline take-or-pay percentages are assigned to each category of gas using the EIA-758 data.

Distribution Pricing. Flexible pricing by distributors is assumed in this study for industrial and electric utility gas users that can switch to oil. If the usual calculated tariff to these users results in the price being higher than the residual fuel oil prices, these consumers are assumed to receive gas prices at parity with the price of residual fuel. However, prices to these customers are not reduced below 95 percent of the distributor's average purchased gas costs. When prices to these customers are reduced, half of the revenue loss by large distributors is passed to gas users that do not have the option of quickly switching to oil.

Lower-48 Reserves and Production. Analysis of the supply outlook through 1990 requires detailed data on prices, reserves, and production for each NGPA category and for each pipeline system. These data are not available from a single source; consequently, several data sources were used either directly or to allocate the information to the level of detail required.

Reserves, production, and price data were developed for 17 domestic pipeline systems. Reserves and production data were obtained from two sources, Forms FERC-15 and EIA-23. The FERC-15 data include reserves and production information reported by interstate pipeline companies for different geographic areas. The Form EIA-23 survey, a sample of oil and gas operators stratified by size, contains data on total reserves and production for each state.

To allocate reserves and production by NGPA category, two additional data systems were used. The Purchase Gas Adjustment data provide projected wellhead purchase volumes by NGPA Category for 20 interstate pipeline companies. These were used to allocate reserves and production for those 20 companies, using the ratio of purchases by section to total purchases. The remaining interstate companies and intrastate area reserves were apportioned in a similar manner, using the FERC-121 and FERC-123 data system, which includes data on production by region, company, interstate or intrastate market, and NGPA category and subcategory

These data were then benchmarked to 1980 and 1982 reserves and production data.

Other Data. A number of features of the model require user-specified parameter values, including discount rates, costs, finding rates, and productivity. The discount rates used in the discounted cash flow calculations are generally 10 percent for developmental drilling projects and 12 percent for exploratory drilling projects. From 1982 to 1984, the discount rates are 15 and 20 percent for developmental and exploratory drilling projects, respectively. The higher rates reflect the influence of greater uncertainty in those years surrounding the world oil price and the regulatory environment in the natural gas market. The expected prices used in the DCF calculations are based on expected constant prices. Revenue values in the DCF computation include revenues from coproducts.

Other user options are related to the costs of exploration and development. All growth rates refer to real changes in costs. Drilling costs grow at 3 percent per year. Since marginal lease acquisition costs are close to zero, lease acquisition costs are set at zero. Geological and geophysical costs, lease equipment costs, and operating costs all are estimated from the Annual Survey of Oil and Gas are constant in real terms.

Alaska as a source of natural gas is omitted, but not ignored. The expected start date for flow of gas from Prudhoe Bay has steadily receded. The earliest official date is late 1989. Given the high degree of uncertainty surrounding several key issues, most notably the financing of the pipeline, Alaska is not included in the group of domestic supply sources in this analysis.

Petroleum Refining Assumptions

Refinery Acquisition Cost. The world oil price is defined as the average refiner acquisition cost of imported crude oil. Domestic crude is priced at this refiner acquisition cost of imported crude.

Imports. Refined product imports are generally assumed to constitute the same regional proportion of demand as in 1982, as described in the 1982 Petroleum Supply Annual. However, the percentage yield of residual fuel can not increase more than 5 percent annually, on a regional basis. Increases in demand which would exceed this are supplied by residual fuel imports. Petrochemical feedstock imports are also adjusted so that the refinery yield remains constant.

Road-Use Taxes. Gasoline prices reflect State taxes and the Federal tax which increased from 4 cents to 9 cents per gallon on April 1, 1983. Taxes are added to diesel fuel at the same rate as gasoline.

Regional Capacity Utilization. Regional production of petroleum products is adjusted so that the capacity utilization rate is the same across Regions 1 through 7 and between Regions 9 and 10.

Coal Assumptions

Exports. Export projections are derived from the EIA's International Coal Trade Model (ICTM).[20] It is assumed that U.S. rail transportation rates for export coal will remain deregulated. Average rail rates are assumed to increase by 35 percent from 1983 to 1995, in real terms. No U.S. ports are assumed to be deepened. However, topping-off operations are permitted in loading large colliers at U.S. ports.

Emission Standards. Utilities are assumed to meet regional standards based on existing 1982 air pollution control regulations. Those that do not have scrubbers are required to meet one of the following standards. Corresponding to each standard is the maximum sulfur content of the coal which may be used.

Standard (lbs SO_2/MBtu)	Coal Sulfur Categories (lbs sulfur/MBtu)
0.68 - 0.80	0.00 - 0.40
0.81 - 1.20	0.41 - 0.60
1.21 - 1.66	0.61 - 0.83
1.67 - 3.34	0.84 - 1.67
3.35 - 5.00	1.68 - 2.50
Over 5.00	Over 2.50
NSPS	0.41 - 0.60

For plants meeting Revised New Source Performance Standards, the choice of which coal sulfur category to burn is based on the delivered cost of the different coals less an adjustment factor. This adjustment factor is a regional credit for use of a lower sulfur coal than required to meet the standard. The credit reflects the reduction in plant operating costs resulting from scrubbing lower sulfur coal. However, the utility is charged the delivered cost of the coal chosen.

Utility Coal Use. Plants that have a contract for coal shipments in 1982 are assumed to burn that coal in 1982. In the forecast years, the contract shipment is decremented based on depletion of individual mine reserves. The size of the decrement is based on the estimated life remaining for mines existing in 1980, for both surface and deep mines, in each region. Plants that do not have a contract for coal shipments select the most economical coal type that satisfies the environmental standards they are required to meet.

Industrial Coal Use. Industrial boilers existing as of 1974 are considered to be "old" and are assumed to reduce coal consumption by 3 percent per year. These industries are allowed to burn high sulfur coal. Those boilers which came on line after 1974 are characterized as "new" and are allowed to use only low-sulfur coal.

Metallurgical Coal Use. Metallurgical coal demand is assumed to be met by a blend of 86 percent premium-grade coking coal and 14 percent marginal-grade coking coal.

Transportation Rates. Domestic rail rates, which are a function of fuel costs and right-of-way rehabilitation costs, are assumed to increase from 1983 to 1995 by approximately 35 percent. Barge and collier rates, which are functions of the world oil price and are more sensitive to fuel costs than rail rates, are assumed to increase from 1983 to 1995 by approximately 50 percent.

Footnotes to Appendix D

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Model List and Contacts

Oil Market Simulation (OMS) Model: Office of Energy Markets and End Use
Dan Butler (202) 252-9503

Outer Continental Shelf (OCS) Model: Office of Oil and Gas
William Trapmann (202) 252-6408

Gas Analysis Modeling Systems (GAMS): Office of Oil and Gas
Richard O'Neill (202) 252-4680

Production of Onshore Lower-48 Oil and Gas (PROLOG) Model: Office of Oil and Gas
William Trapmann (202) 252-6408

Alaskan Hydrocarbon Supply Model: Office of Oil and Gas
William Trapmann (202) 252-6408

Resource Allocation and Mine Costing (RAMC) Model: Office of Coal, Nuclear, Electric, and Alternate Fuels
Robert Crockett (202) 252-4266

Coal Supply and Transportation Model (CSTM): Office of Coal, Nuclear, Electric and Alternate Fuels
Jarvis Seely (202) 252-6853

International Coal Trade Model (ICTM): Office of Coal, Nuclear, Electric and Alternate Fuels
Ercan Tukenmez (202) 252-5253

Conceptual Capital Cost Model (CONCEPT-5): Office of Coal, Nuclear, Electric and Alternate Fuels
Arthur Fuldner (202) 252-9852

National Utility Financial Statement (NUFS) Model: Office of Coal, Nuclear, Electric, and Alternate Fuels
Gerald Price (202) 252-9854

Intermediate Future Forecasting System (IFFS): Office of Energy Markets and End Use

Oil/Gas:	Susan Shaw	(202) 252-1468
Coal:	Reginald Sanders	(202) 252-1466
Electricity:	Reginald Sanders	(202) 252-1466
Macroeconomic:	William Curtis	(202) 252-1455
Residential:	John Holte	(202) 252-1471
Commercial	John Holte	(202) 252-1471
Industrial:		
Major Fuels:	Paul Werbos	(202) 252-1197
Minor Fuels:	Paul Werbos	(202) 252-1197
Transportation:	Barry Cohen	(202) 252-5359
Refineries:	Michael Lehr	(202) 252-1470

Appendix E
Sectoral Definitions and Fossil Fuel Terminology

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Sectoral Definitions and Fossil Fuel Terminology

Residential Sector: Energy consumed by private household establishments primarily for space heating, water heating, air conditioning, cooking, and clothes drying. This sector's consumption does not include consumption by individual households that are located in master metered apartment buildings.

Commercial Sector: Energy consumed by nonmanufacturing business establishments. Included are motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; health, social, and educational institutions; and energy consumed by Federal, State and local government. This sector includes consumption by individual households that are located in master metered apartment buildings. The consumption of motor gasoline by this sector has been transferred to the transportation sector.

Industrial sector: Energy consumed by manufacturing, construction, mining, agriculture, fishing, and forestry establishments. Natural gas consumed as a lease and plant fuel, motor gasoline, jet fuel, industrial hydroelectric power and refinery fuel, except for electricity and coal, are excluded from this sector. Lubricants consumed by the industrial sector include transportation sector lubricants.

Transportation Sector: Energy consumed to move people and commodities in both private and public sectors included are military, railroad, vessel bunkering, and marine uses. Natural gas used as a pipeline fuel and lubricants are excluded from this sector.

Electric Utility Sector: Energy consumed by private and publicly owned establishments which generate electricity primarily for resale.

Refinery Sector: Fuels consumed by petroleum refineries for all purposes, except coal and electricity, that are included in the industrial sector.

Coal Terminology

Anthracite: A hard, jet black coal with a high luster used for generating electricity and space heating. Its ignition temperature is approximately 925 to 970 degrees Fahrenheit. Anthracite is mined almost exclusively in northeastern Pennsylvania.

Bituminous Coal: The most common coal, also known as soft coal. It is dense, black, often with well-defined bands of bright and dull material, and is used for generating electricity, making coke, and space heating. The ignition temperature is 700 to almost 900 degrees Fahrenheit. Bituminous coal is mined chiefly in the Appalachian and interior coal fields.

Blast Furnace: A furnace in which solid fuel (coke) is used as a fuel and as a reducing agent and limestone is used as a flux to smelt iron ore.

Btu (British Thermal Unit: A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.

Coal Carbonized: The amount of coal that was decomposed into solid (coke and breeze), liquid, and gaseous products by heating it in a coke oven in a limited air supply or in the absence of air.

Coal Producing Districts: A classification of coal fields defined in the Bituminous Coal Act of 1937. The districts were originally established to aid in formulating minimum prices of bituminous and subbituminous coal and lignite. Because much statistical information was compiled in terms of these districts, their use for statistical purposes has continued since the abandonment of that legislation in 1943.

Coal Producing Regions: A geographic classification of coal producing States. The States in the Appalachian regions are Alabama, Georgia, eastern Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia. The States in the Interior region are Arkansas, Illinois, Indiana, Iowa, Kansas, western Kentucky, Louisiana, Missouri, Oklahoma, and Texas. The States in the Western region are Alaska, Arizona, Colorado, Montana, New Mexico, North Dakota, Utah, Washington, and Wyoming.

Coal Rank/Group: A classification of coal based on fixed carbon, volatile matter, and heating value. It is an indication of the progressive alteration, or coalification, from lignite to anthracite.

Coke: The strong porous residue consisting of carbon and mineral ash. It is formed when the volatile constituents of bituminous coal are driven off by being heated in a limited air supply or in the absence of air. It is most often used as a fuel source and as a reducing agent in a blast furnace.

Coke Plants: Plants where coal is carbonized in slot or beehive ovens for the manufacture of coke.

C.I.F. Cost: Cost including insurance and freight costs. The delivered cost of coal.

F.A.S. Value: Free Alongside Ship value. This is the value of a commodity at the port of exportation. It generally includes the purchase price plus all charges incurred in placing the commodity alongside the carrier at the port of exportation in the country of exportation.

F.O.B. Mine Price: The free on board mine price. This is the price paid for coal measured in dollars per short ton at the mining operation site and therefore does not include freight/shipping and insurance costs.

Lignite: A brownish black coal having a high moisture content and used mainly to generate electricity. It has an ignition temperature of approximately 600 degrees Fahrenheit. It is mined in North Dakota, Montana, and Texas, and is expected to be mined in Louisiana during the forecast period.

Short Ton: A unit of weight equal to 2,000 pounds.

Stocks: The supply of coal or coke at the mine, plant, or utility at the end of a specific period of time.

Subbituminous Coal: A type of coal having a dull back color. It is used for generating electricity and space heating and is mined in the western coal fields.

Natural Gas Terminology

Allowables: The maximum rate of production from a well or group of wells that is allowed by a particular State or governing body. The rate is set by rules which vary among the various States or governing bodies.

Associated-dissolved Gas: Natural gas occurring in reservoirs with crude oil either as free gas (associated) or as gas in solution with the crude oil (dissolved).

Categories of gas: Natural gas as defined by the NGPA, designated by the section of the act in which they are defined:

Section 102 - New Natural Gas - Gas from new (discovered after 7/27/76) reservoir on old offhore lease, gas from new (post 4/20/77) offshore gas leases, and new (post 4/20/77) onshore wells at least 2.5 miles from the nearest old well or 1,000 feet deeper than any well within 2.5 miles.

Section 103 - Gas from wells, the surface drilling of which began after 2/19/77, but which does not qualify for Section 102 because the well is within 2.5 miles of an old well and not 1,000 feet deeper than deepest completion location within 2.5 miles.

Section 104 - Gas Dedicated to Interstate Commerce before NGPA Enactment (November 9, 1978) including flowing gas and gas from certain designated locations.

Section 105 - Gas Under Existing Intrastate Contracts not dedicated to interstate commerce on 11/9/78. - Gas sold under such contracts in place at date of enactment.

Section 106 - Sales of Gas Made Under "Rollover" Contracts - Section 104 and 105 Gas under contracts that are renegotiated upon expiration.

Section 107 - High Cost Natural Gas - Gas from wells drilled after February 19, 1977, that are 15,000 feet or deeper, gas from coal seams, Devonian shale, tight sands or geopressurized brine.

Section 108 - Stripper Well Natural Gas - Nonassociated natural gas produced at low flow rates.

Section 109 - Production from wells not covered above, largely Prudhoe Bay Alaskan gas.

Ceiling Price: The maximum price a producer is allowed to collect under the Natural Gas Policy Act for a first sale of gas.

High-Cost Gas: Terminology used for Section 107 sources of gas, most of which is either deregulated or benefits from relatively high ceiling prices.

Incremental Pricing: Those provisions of the NGPA written to pass the cost of higher priced gas to large industrial consumers. The industrial customers were required to pay the increased cost until their cost reached a level computed from the equivalent price of fuel oil. Due to the high number of exemptions granted, the incremental pricing provisions have had little impact on consumer prices.

Interstate Gas: Natural gas that is dedicated to interstate commerce.

Intrastate Gas: Natural gas that is produced and consumed within one state's boundaries and transported by nonjurisdictional pipelines. As such, the gas was not subject to any Federal regulation until the enactment of the Natural Gas Policy Act of 1978 (NGPA).

Loss and Unaccounted For Gas: Actual natural gas losses such as those due to leaks or the merging of new pipelines, customers coming on or leaving the system, meter breakdowns resulting in estimated billing.

Natural Gas Policy Act of 1978 (NGPA): Legislation providing: a broad range of price controls on domestically produced gas, with price regulations extended to gas that had not been regulated earlier; a schedule of price increases leading to decontrol of most gas at specified future dates; and a mechanism for shifting most of the burden for the higher cost, new gas supplies on industrial consumers who could potentially convert to coal.

New Gas: Terminology generally used to describe Section 102 and 103 gas or, less frequently, Section 102, 103, and 107, 108, and 109 gas.

Nonassociated Gas: Free natural gas not in contact with crude oil in the reservoir.

Off-system Sales: Natural gas sales made by pipelines to new customers in order to dispose of surplus gas that the pipelines' traditional markets cannot take.

Old Gas: Terminology used to encompass several of the NGPA categories, generally Sections 104, 105, and 106 gas. This loosely defines old wells and reservoirs existing at the time of NGPA enactment.

Pipegate: The point of a gas purchase between a producer and first purchaser. The quantity purchased is usually less than wellhead production primarily due to the removal of lease and plant fuel. Then price is usually higher due to gathering and processing charges.

Pipeline: The company that receives the gas from the producer and transports it for delivery to either another pipeline, a local distribution company or to end-use consumers. The pipeline company generally purchases the gas from the producer after field handling of the gas or directly at the wellhead and resells it to a local distribution company. Whether or not the pipeline operates across State boundaries determines its classification as interstate or intrastate.

Producer: That company or entity that drills, maintains, and operates the gas or gas/oil well. The producer may also perform the gathering and initial field handling and processing of the gas.

Proved Reserves: Geological deposits of gas known to exist and to be economically recoverable using current technology.

Purchased Gas Adjustment (PGA) Filings: Filings submitted by major interstate pipeline companies to the Federal Energy Regulatory Commission. These submissions allow the companies to recover the difference between their anticipated actual purchase consts for natural gas and the costs reflected in their current rate structure.

Take-or-Pay Provision typically found in contracts between producers and pipeline purchasers which requires the purchaser to take, or pay for even if not taken, a certain quantity of gas. Some percentages are based on minimum daily quantities, annual quantities, or minimum contract quantities. Take-or-pay quantities may change over time under initial provisions of the contract or may be changed in an amendment to the contract.

Unconventional Gas: Natural gas resources characterized by the geologic environment, including tight gas reservoirs, Devonian shale, coal seams, and geopressurized brine.

Wellhead: The point at which natural gas is transferred from the well to pipeline or other non-well facility. This term is used in referring to "wellhead price," which is the price producers of natural gas receive not including reimbursement for severance taxes and other production related costs.

Petroleum Terminology

Alcohol: The family name of a group of organic chemical compounds composed of carbon, hydrogen, and oxygen. The series of molecules vary in chain length and are composed of a hydrocarbon plus a hydroxyl group, CH-(CH)n-OH. "Alcohol" includes ethanol and methanol.

Asphalt: A dark-brown-to-black material, containing bitumens as the predominant constituents, obtained either naturally or by petroleum procession. It is the residue from the distillation of an asphaltic crude oil or the insoluble portion from an extraction process that utilizes propane or other suitable solvents. The definition includes crude asphalt as well as the following finished products: cements, fluxes, the asphalt content of emulsion (exclusive of water), and petroleum distillates blended with asphalt to make cutback asphalts. The conversion factor is 5.5 42-gallon barrels per short ton.

Aviation Gasoline (Finished): All special grades of gasoline for use in aviation reciprocating engines, as given in ASTM Specification D 910 and Military Specification MIL-G-5572. "Aviation gasoline" includes all refinery products within the gasoline range that are to be marketed straight or in blends as aviation gasoline without further refinery processing.

Barrels: A volumetric unit of measure of crude oil and petroleum products equivalent to 42 U.S. gallons. This measure is used in most statistical reports. Factors for converting petroleum coke, asphalt, wax, and still gas to barrels are given in the definitions for these products.

Barrels Per Calendar Day: The number of barrels per stream day of input to crude oil processing units that can be processed by a refinery in an average 24-hour period after making allowances for the following limitations: downstream limitations, environmental constraints, types and grades of input, planned and unplanned downtime, and types of grades of products.

Barrels Per Stream Day: The amount a unit can process running at full capacity under optimal crude and product slate conditions.

Catalytic Cracking: Basically the same as thermal cracking since heat is used, but differs in its use of a catalyst to direct the cracking reaction to produce more of the higher octane hydrocarbons; provides a motor spirit of 10 to 15 octane numbers higher than that of the thermally cracked product and is more effective in producing isoparaffins and aromatics, all of which are of high antiknock qualities or value. Modern cracking units are one of two types: the "fluid process" uses a finely powdered catalyst which is moved and circulated through the system by a "fluidized-solid" technique, and the other, "moving bed process," in which pellet catalysts are circulated by elevators or gas-lift method.

Catalytic Hydrocracking: A refining process for converting middle-boiling or residual material to high-octane gasoline, reformer charge stock, jet fuel, and/or high grade fuel oil. Hydrocracking is an efficient, relatively low-temperature process using hydrogen and catalyst.

Catalytic Hydrofining: A process for improving the quality of petroleum products, especially gasoline, by treating them with hydrogen in the presence of a catalyst, at a temperature below that at which decomposition occurs.

Catalytic Hydrotreating: A process of treating petroleum fractions and unfinished oils in the presence of catlysts and substantial quantities of hydrogen to upgrade their quality.

Catalytic Reforming: The use of controlled heat and pressure with catalysts to effect the rearrangement of certain hydrocarbon molecules without altering their composition appreciably; the conversion of low-octane gasoline fractions into higher octane stocks suitable for blending into finished gasoline; also the conversion of naphthas to obtain more volatile product of higher octane number.

Crude Distillation: The processing of separating crude oil components by heating and subsequent condensing of the fractions by cooling.

Crude Oil: A naturally occurring mixture of liquid hydrocarbons that remains liquid at atmospheric pressure after passing through surface separating facilities. Lease condensate is included. Drips are also included, but topped crude (residual) oil and other unfinished oils are excluded. Liquids produced at natural gas processing plants and mixed with crude oil are likewise excluded where identifiable.

Crude Oil Type

- Sweet - Under 0.5 wt. % sulfur
  Light Medium - 15% or less @ 1050°F. + residuum assay
  Heavy High - Greater than 15% @ 1050°F + residuum assay

- High Sulfur - in excess of 1.0 wt. % sulfur
  Light High - 15% or less @ 1050°F. + residuum assay

- Domestic - Crude oil produced in the United States or from its outer continental shelf as defined in 43 U.S.C. 1331. Synthetic hydrocarbons such as shale oil and tar sand oil are included.

- Foreign - Crude oil produced outside the United States. Imported Athabasca hydrocarbons are reported as crude oil.

Distillate Fuel Oil: A general classification for one of the petroleum fractions which, when produced in conventional distillation operations, has a boiling range of 400 degrees Farenheit at the 10-percent point to 640 degrees Farenheit at the 90-percent point. It is used primarily for space heating, on- and off-highway diesel engine fuel (including railroad engine fuel and fuel for agricultural machinery), and electric power generation. Included are products known as No. 1 and No. 2 heating oils, diesel fuels, and No. 4 fuel oil.

Feedstocks: Crude oil or other hydrocarbons that are the basic materials for a refining or manufacturing process.

Field Production: Represents crude oil production on leases, natural gas liquids production at natural gas processing plants, and new supply of other hydrocarbons and alcohol.

Hydrogen: A colorless, highly flammable gaseous element, the lightest of all gases and the most abundant element in the universe, used in the production of synthetic ammonia and methanol, in petroleum refining, and in hydrogenation of organic materials.

Kerosene: A petroleum distillate that boils at a temperature between 300 and 550 degrees Farenheit, that has a flash point higher than 100 degrees Farenheit by ASTM Method D 56, that has a gravity range from 40 degrees to 46 degrees API, and that has a burning point in the range of 150 to 175 degrees Farenheit. It is a clean-burning product suitable for use as an illuminant when burned in wick lamps. Includes grades of kerosene called range oil having properties similar to No. 1 fuel oil, but with a gravity of about 43 degrees API and having a maximum end-point of 625 degrees Farenheit. Kerosene is used in space heaters, cook stoves, and water heaters.

Kerosene-Type Jet Fuel: A quality kerosene product with an average gravity of 40.7 degrees API, a 10-percent distillation temperature of 400 degrees Farenheit, and an endpoint of 572 degrees Farenheit. It is covered by ASTM Specification D 1655 and Military Specification MIL-T-5624L (Grade JP-5 and JP-8). It is used primarily for commercial turbojet and turboprop aircraft engines.

Lease Condensate: A natural gas liquid recovered from gas well gas (associated and nonassociated) in lease separators or natural gas field facilities. Lease condensate consists primarily of pentanes and heavier hydrocarbons.

Lubricants: A substance used to reduce friction between bearing surfaces. Petroleum lubricants may be produced either from distillates or residues. Other substances may be added to import or improve certain required properties. "Lubricants" includes all grades of lubricating oils from spindle oil to cylinder oil and those used in greases. The three categories reported are:

- Bright Stock - A refined, high viscosity lubricating oil base stock that is usually made from a residuum by a treatment such as deasphalting, acidtreatment, or solvent extraction.

- Neutral - A distillate lubricating oil base stock with a viscosity that is usually not above 550 Saybolt Seconds Universal (SSU) at 100 degrees Farenheit. It is prepared by a treatment such as hydrofining, acid treatment, or solvent extraction.

- Other - A lubricating oil base stock used in finished lubricating oils and greases, including black, coastal, and red oils.

Miscellaneous Products: Includes all finished products not classified elsewhere. "Miscellaneous products" include petroleum, absorption oils, ram-jet fuel, petroleum rocket fuels, synthetic natural gas feedstocks, and naphthas.

Motor Gasoline (Finished): A complex mixture of relatively volatile hydrocarbons, with or without small quantities of additives for use in spark-ignition engines. Specifications for motor gasoline, as given in ASTM Specification D 439 or Federal Specification VV-G-1690B, include a boiling range of 122 to 158 degrees Farenheit at the 10-percent point to 365 to 374 degrees Farenheit at the 90-percent point and a Reid vapor pressure range from 9 to 15 psi. "Motor gasoline" includes finished leaded gasoline, finished unleaded gasoline, and gasohol. Blendstock is excluded until blending has been completed. Alcohol that is to be used in the blending of gasohol is also excluded.

- Leaded Gasoline - Contains more than 0.05 grams of lead per gallon or more than 0.005 grams of phosphorus per gallon. The actual lead content of any given gallon, however, may vary as a function of the size of the producer and company according to specific Environmental Protection Agency waiver provisions. Premium and regular grades are included, depending on the octane rating.

- Unleaded Gasoline - Contains up to 0.05 grams of lead per gallon and 0.005 grams of phosphorus per gallon. Premium and regular grades are included, depending on the octane rating.

- Gasohol - A blend of alcohol and finished motor gasoline that is more than 90 percent of finished motor gasoline (leaded or unleaded are described above) and no less than 10 percent or more alcohol (ethanol or methanol).

Naphtha: A colorless flammable liquid, obtained from crude petroleum and used as a solvent and cleaning fluid and as a raw material for gasoline.

Naphtha-Type Jet Fuel: A fuel in the heavy naphtha boiling range with an average gravity of 52.8 percent API and 20 to 90 percent distillation temperatures of 290 to 470 degrees Farenheit, meeting Military Specification MIL-T-5624L (Grade JP-4). JP-4 is used for turbojet and turboprop aircraft engines, primarily by the military. This category excludes ram-jet and petroleum rocket fuels, which are included in the "Miscellaneous Products" category.

Natural Gas Plant Liquids: Natural gas liquids recovered from natural gas in gas processing plants and in some situations, from natural gas field facilities. Natural gas liquids extracted by fractionators are also included. These liquids are defined according to the published specifications of the Gas Processors Association and the American Society for Testing and Materials, and are classified as follows: ethane, propane, ethane-propane mix, isobutane, butane, butane-propane mix, isopentane, natural gasoline, plant condensate, unfractionated stream, and other products from natural gas processing plants (i.e., products meeting the standards of finished petroleum products produced at natural gas processing plants, such as finished motor gasoline, finished aviation gasoline, special naphthas, kerosene, distillate, fuel oil, and miscellaneous products).

Operable Capacity: Represents the status of processing units at a petroleum refinery. Operable capacity is the sum of operating and idle capacity.

- Operating capacity - Capacity that is in operation.
- Idle Capacity - Capacity not in operation but capable of being placed in operation within 90 days.

Permanently Shutdown: A classification for petroleum refineries which represents refineries which have ceased operation and/or are incapable of being placed in operation within 90 days.

Petroleum Products: Petroleum products obtained from the processing of crude oil (including lease condensate), natural gas, and other hydrocarbon compounds. Petroleum products include unfinished oils, natural gasoline and isopentane, plant condensate, unfractionated stream, ethane, liquefied petroleum gases, aviation gasoline, motor gasoline, naphtha-type jet fuel, kerosene-type jet fuel, kerosene, distillate fuel oil, residual fuel oil, naphtha-less than 400 degrees Farenheit end-point, special naphthas, lubricants, waxes, petroleum coke, asphalt, road oil, still gas, and miscellaneous products.

Petroleum Refinery: An installation that manufactures finished petroleum products from crude oil, unfinished oils, natural gas plant liquids, other hydrocarbons, and alcohol.

Primary Stocks: Stocks of crude oil or petroleum products held in storage by refineries, natural gas processing plants, pipelines, tankfarms, and bulk terminals. Crude oil that is in transit from Alaska or that is stored on Federal leases is included. Bulk terminals are facilities that can store at least 50,000 barrels of petroleum products or that can receive petroleum products by tankers, barge, or pipeline. "Primary Stocks" excludes stocks of foreign origin that are meant for domestic consumption but have not clear the United States Customs Service.

Residual Fuel Oil: Topped crude of refinery operations. "Residual Fuel Oil" includes No. 5 and No. 6 fuel oils as defined in ASTM, Specification D 396 and Federal Specification VV-F-815C; Navy Special fuel oil as defined in Military Specification MIL-F859E including Amendment 2; Bunker C fuel oil; an acid sludge used for refinery fuels. Residual fuel oil is used for the production of electric power, space hearting, vessel bunkering, and various industrial purposes.

- Bunker C- A heavy residual fuel oil used by ships and industry and for heating large-scale installations; also referred to as No. 6 fuel oil.

Road Oil: Any heavy petroleum oil, including residual asphaltic oils, used as a dust palliative and surface treatment of roads and highways. It is generally produced in six grades, from 0, the most liquid, to 5, the most viscous.

Special Naphthas: All finished products within the gasoline range that are used as paint thinners, cleaners, and solvents. These products are refined to a specified flash point and have a boiling range of 90 to 220 degrees Farenheit.

Electricity Terminology

Baseload Capacity: Capacity of the generating equipment normally operated to serve loads on a continuous basis.

Boiler: Part of a steam turbine in which water is boiled to produce steam. It consists usually of metal shells and tubes.

Capability: Maximum load that a generating unit, generating station, or other electrical apparatus can carry under specified conditions for a given period of time, without exceeding approved limits of temperature and stress.

Capacity: Amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated.

Contract Cost: Price of fuels marketed on a contract basis covering a period of one or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or would be adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Electric Utility: An enterprise engaged in the production, transmission, or distribution of electricity for use by the public, includes investor-owned, cooperatively owned, and Government-owned (municipal systems, Federal agencies, State projects and public power districts).

Firm Gas: Gas sold on a continuous and generally long-term contract.

Forced Outage: Generating equipment that is unavailable for load due to an emergency.

Gas: Includes natural gas, coke-oven gas, blast-furnace gas, and refinery gas. Manufactured gas is included in FERC Form 423 reporting as natural gas.

Gas-Turbine Plant: A plant in which the prime mover is a gas-turbine engine. A gas turbine consists typically of an axial-flow air compressor, one or more combustion chambers where liquid or gaseous fuel is burned in excess air, and a turbine, where the hot gases are expanded to drive the compressor and generator.

Generation: The act or process of producing electric energy from other forms of energy; also, the amount of electric energy, expressed in watthours (Wh).

Generator: A machine used to change mechanical energy into electric energy.

Geothermal Plant: A plant in which the prime mover is a steam turbine. The turbine is driven either by steam produced from hot water or by natural steam, both trapped below the surface of the earth's crust.

Gigawatt (GW): One billion watts.

Gigawatthour (GWh): One billion watthours.

Gross Generation: Total amount of electric energy produced by the generating units in a generating station or stations, measured at the generator terminals.

Heavy Oil: The fuel oils remaining after the lighter oils have been distilled off during the refining process. Except for start-up and flame stabilization, virtually all oil used in steam plants is heavy oil.

Hydroelectric Power Plant: A plant in which the prime mover is a waterwheel driven by falling water.

Installed Nameplate Capacity: The capacity as shown on the manufacturer's identification plate. This appears on apparatus, such as generating units, turbines, or other equipment in a station or system. Installed station capacity does not include auxiliary or house units. The nameplate capacity is the full-load continuous rating of a generation, prime mover, or other electrical equipment under specified conditions as designated by the manufacturer. It is usually indicated on a nameplate attached mechanically to the equipment.

Instantaneous Peak Demand: Maximum demand at the instant of greatest load.

Internal Combustion Plant: A plant in which the prime mover is an internal combustion engine. An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel engines are the principal types used in electric plants.

Interruptible Gas: Gas sold to customers with a provision that permits curtailment or cessation of service at the discretion of the distributing company under certain circumstances as specified in the service contract.

Kilowatt (kW): One thousand watts.

Kilowatthour (kWh): One thousand watthours.

Light Oil: Lighter fuel oils distilled off during the refining process. Virtually all oil used in internal combustion and gas-turbine engines is light oil.

Load (Electric): Amount of electric power delivered or required at any specific point or points on a system.

Maximum Demand: Greatest of all demands of the load under consideration occurring within a specified period of time.

Megawatt (MW): One million watts.

Megawatthours (Mwh): One million watthours.

Net Capability: Net capability of a generating station is the amount of energy that could be produced as demonstrated by test or as determined by actual operating experience less power generated and used for station uses. Net capability may vary with the character of the load, time of year (due to circulating water temperatures in thermal stations or availability of water in hydroelectric power stations), and other characteristic causes.

Net Energy for Load: Net generation of main generating units that are system-owned or system-operated plus energy receipts minus energy deliveries.

Net Generation: Gross generation less the electric energy consumed at the generating station for station use. Energy required for pumping at pumped-storage plants is regarded as plant use and must be deducted from the gross generation. (See Generation, Gross Generation.)

North American Electric Reliability Council (NERC): In 1968, the electric industry created the NERC to augment the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of nine reliability council regions and encompasses essentially all the power systems of the contiguous U.S. and the Canadian systems in Ontario, British Columbia, Quebec, Manitoba, and New Brunswick. The NERC regions are:

ECAR - East Central Reliability Coordination Agreement
MAIN - Mid-American Interpool Network
MAAC - Mid-Atlantic Area Council
MAPP - Mid-Continent Area Power Pool
NPCC - Northeast Power Coordinating Council
SERC - Southeastern Electric Reliability Council
SWPP - Southwest Power Pool
ERCOT - Electric Reliability Council of Texas
WSCC - Western Systems Coordinating Council

Nuclear Fuel: Fuel containing fissionable materials of such composition and enrichment that when placed in a nuclear reactor will support a self-sustaining fission chain reaction and produce heat in a controlled manner for process use.

Nuclear Power Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a reactor by heat from the fissioning of nuclear fuel.

Off Peak Gas: Gas which is to be delivered and taken on demand when demand is not at its peak. (See Spot Purchase.)

Other Gas: Includes manufactured gas, coke-oven gas, blast-furnace gas, and refinery gas. Manufactured gas is obtained by distillation of coal, by the thermal decomposition of oil, or by the reaction of steam passing through a bed of heated coal or coke. (See Natural Gas.)

Other Generation: Other generation includes solar and geothermal generation, and generation from wood, waste, and wind. (See Generation, Geothermal Plant.)

Other Unavailable Capability: Net capability of generating units that are unavailable for load for reasons other than full-forced outage or scheduled maintenance such as partial outages, legal restrictions.

Peaking Capacity: Generating equipment normally operated during the hours of highest daily, weekly, or seasonal loads. Some generating equipment may be operated at certain times as peaking capacity and at other times to serve loads on a continuous basis.

Peak Load: Maximum load during a specified period of time.

Peak Load Plant: A plant, usually housing, gas turbines, diesels, or pumped-storage hydroelectric equipment old, low-efficiency steam units,normally used during the peak load periods.

Plant Use Electricity: Electric energy used in the operation of a plant. Included in this definition is the energy required for pumping at pumped-storage plants.

Prime Mover: The engine, turbine, water wheel, or similar machine which drives an electric generator. For the purpose of this publication, prime mover represents the aggregation of all like equipment within a plant.

Pumped-Storage Plant: A hydroelectric plant which uses water previously pumped into a storage reservoir during off-peak periods. Usually this type of plant generates electric energy during peak load periods.

Reserve Margin: Amount of unused available capability of a generating station at peak load.

Running and Quick-Start Capability: Refers to generating units that can be available for load within a 30-minute period.

Scheduled Maintenance: Net capability of generating units that are unavailable for load due to inspection or maintenance in accordance with an advance schedule.

Spot Purchase: A single shipment of fuel or volumes of fuel to be delivered within 1 year. Spot purchases are often made by a user to fulfill a certain portion of energy requirements or to meet unanticipated energy requirements usually at a higher than normal cost.

Station (Electric): A plant containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or nuclear energy into electric energy.

Steam-Electric (Conventional) Plant: A plant in which the prime mover is a steam turbine. The steam used to drive the turbine is produced in a boiler by heat from burning fossil fuels.

Stocks (Fuel): A supply of fuel accumulated for future use. This includes coal and fuel oil stocks at the plant site, in coal cars or barges at the plant site, and stocks held in central storage yards.

Transmission: Act or process of transporting electric energy in bulk from a source or sources of supply to other principle parts of an electric utility system.

Turbine: A rotary engine usually made of a series of curved vanes attached to a central rotating spindle and actuated by the reaction or impulse or both of a current of fluid (such as water or steam) which is subject to pressure.

Watt: The electrical unit of power or rate of doing work. A watt is the rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor (volt and ampere in phase). It is analogous to horespower or foot-pound-per-minute of mechanical power. A watt is equivalent to approximately 1/746 horsepower.

Watthour (Wh): Equal to 1 watt of power supplied to, or taken from, an electric circuit steadily for 1 hour.

Conversion Factors

Most of the tables in the Annual Energy Outlook, 1983 report values in British Thermal Units (Btu). The table below is provided for the users of this publication who may wish to convert a value reported in Btu into its physical units. The conversion factors listed correspond to the estimated Btu content of the various fuels at the time of consumption in 1983. Unless otherwise noted, the conversion factors were obtained directly from the Annual Energy Review, 1983. When aggregated fuel categories are reported, the included fuels are listed with their conversion factors. The conversion factors for the aggregate fuels appear in parenthesis in the table below. In most cases, these conversion factors were applied to the projected values as well.

Sector/Energy Category	Conversion Factors	Units
Residential		
Distillate	5.825	MMBtu/BBL.
Kerosene	5.670	" "
LPG(1)	3.643	" "
Steam Coal(2)	[a](22.71)	MMBtu/Short ton
Bit. & Lignite	22.30	" "
Anthracite	25.20	" "
Natural Gas	1,026	Btu/Cu.Ft.
Electricity	3,412	Btu/kWh
Commercial		
Distillate	5.825	MMBtu/BBL.
Residual Fuel	6.287	" "
Motor Gasoline	5.253	" "
Kerosene	5.670	" "
LPG(1)	3.643	" "
Steam Coal(2)	[a](22.71)	MMBtu/Short ton
Bituminous	22.30	" "
Anthracite	25.20	" "
Natural Gas	1,026	Btu/Cu.Ft.
Electricity	3,412	Btu/kWh
Industrial		
Distillate	5.825	MMBtu/BBL.
Residual Fuel	6.287	" "
Motor Gasoline	5.253	" "
Kerosene	5.670	" "
LPG(1)	3.643	" "
Asphalt & Road Oil	6.636	" "
Petr. Coke	6.024	" "
Special Naphthas	5.248	" "
Lubricants and Waxes	6.065	" "
Petr. Feedstocks	[b](5.606)	" "
Naphtha	5.248	" "
Still Gas	6.000	" "
Steam Coal(2)	22.65	MMBtu/Short ton
Coking Coal(2)	26.00	" "

Coke Imports	26.00	" "
Natural Gas	1,206	Btu/Cu.Ft.
Hydropower	10,470	Btu/kWh
Electricity	3,412	" "
Transportation		
Distillate	5.825	MMBtu/BBL.
Residual Fuel	6.287	" "
Motor Gasoline	5.253	" "
Aviation Gasoline	5.048	" "
LPG(1)	3.643	" "
Lubricants	6.605	" "
Jet Fuel	[b](5.608)	" "
Naphtha	5.355	" "
Kerosene	5.670	" "
Natural Gas	1,026	Btu/Cu.Ft.
Electricity	3,412	Btu/kWh

[1]Data from Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(83/125[4]) (Washington, D.C., 1984).

[2]In the projected period, coal conversion factors are based on model results. Metallurgical Coal (27.2), Residential/Commercial Coal (24.1), Utility Coal from 21.2 in 1985 to 21.0 in 1995, Industrial Coal increasing from 23.9 to 24.3.

[a]Implied residential/commercial sector conversion factor based on Annual Energy Review, 1983 data in physical and Btu units.

[b]Quantity weights from Energy Information Administration, Petroleum Supply Annual 1981, DOE/EIA-0340(81) (Washington, D.C., 1982).

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