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ANNUAL ENERGY OUTLOOK

LONG-TERM PROJECTIONS

EIA ENERGY INFORMATION ADMINISTRATION

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Annual Energy Outlook 1989

With Projections to 2000

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The projections in this year's *Annual Energy Outlook* were prepared with the PC-AEO modeling system, a set of spreadsheet models of the U.S. energy economy. Inquiries concerning the availability and documentation of this modeling system (or any of EIA's models) should be addressed to EIA's National Energy Information Center (202/586-8800).

Administrator's Message

WHICH STATISTICS ARE REALLY MEANINGFUL?

More than a decade has passed since the Energy Information Administration was created to give independent statistical and analytical support to the Nation's energy policy makers . . . yet the task of producing an "Annual Energy Outlook" has not become a routine, mechanical one. The U.S. energy picture often resembles a swirling montage -- with various statistical indicators moving at different rates and sometimes even in different directions. How can one possibly sort things out?

A good way to begin is by recognizing that a single year does not define a trend. 1988 was a period in which U.S. energy consumption surged -- yet we believe the year's underlying message is that a long-term movement toward greater energy *conservation* is secure. Many of the country's electric utilities have stopped building new power plants because they have surplus generating capacity -- yet EIA suggests that substantial fresh construction might be necessary in a relatively short time. Occasionally it is important for a document such as this one to clarify apparent anomalies of this sort; and we have in fact tried to do so in the following pages.

The U.S. energy outlook cannot be isolated from the future of global markets, so we are ever aware of international context. The price of *oil* on the world market is uniquely crucial -- so our computer projections focus on it intently. In addition to EIA's "base case" forecast we offer a different set of statistics to show what supply, demand and fuel-mix might be if oil prices were either higher or lower than the base by the year 2000. This year we have simplified the assumptions of these "alternative scenarios" so as to concentrate *exclusively* on variations in the modeling results tied directly to these price differences.

It cannot be stressed too often that the projections in this volume are not presented as prophecy. If one makes different assumptions at the outset (or if policies change, or if real-life events on the domestic or world scene surprise everyone) things might be quite different in the year 2000 from the way we have portrayed them. Other competent energy analysts have looked ahead and seen slightly different images on the horizon; we encourage a consideration of divergent opinions to such an extent that we invite specific comparisons with a couple of these in the section that begins on page 33. Nevertheless, the *AEO* represents *this agency's best judgment.*

What are the long-term prospects for various fuels? How serious a problem is the two million barrel per day rise in U.S. oil imports over the past three years? Legislators, executives in the public and concerned members of the American public will form attitudes and take actions on the basis of "what the latest numbers show." If this report helps the process by displaying the facts objectively *and making it somewhat clearer how they interrelate,* it has done its job.

Dr. H. A. Merklein
Administrator
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Contents

Page

Appendices

Tables

Illustrations

Highlights

The United States consumed more energy during 1988 than in any previous year in its history; and U.S. demand for petroleum hovered at about 17 million barrels per day -- the highest point since 1980. Encouragingly, however, the past year also showed that a strong underlying trend toward greater energy efficiency is continuing . . . and that competition for oil from other energy sources (except in the transportation sector) remains a persistent natural curb on petroleum use.

U.S. consumption of energy in all forms increased from 76.8 quadrillion British thermal units (quads) during 1987 to an estimated 79.4 quads in 1988. However, this took place in the context of continuing low oil prices, an economic boom, and unusual extremes in temperature that pushed up energy use in both cold and hot weather. Considering those circumstances, the rise was modest.

Nevertheless, if real gross national product (GNP) grows at an average of 2.5 percent annually (actually, a slower pace than the Nation has set since 1970) while average crude oil prices increase only gradually to the equivalent of $28 per barrel by the end of the century (the projection of this *Annual Energy Outlook*), the *AEO* "base case" calculations suggest that the Nation will be using over 90 quads by the year 2000. Under these assumptions, a decline in U.S. domestic oil production will force importation of more than half the petroleum used here as soon as 1994.

Oil prices depend on levels at which nations utilize their production capacity

Erratic variations in price might be anticipated for several years, while OPEC tries once again to control the combined output of member-countries with dissimilar interests. Furthermore, non-OPEC oil production is still growing -- slowly. By 2000, however, fundamental forces of supply and demand should raise prices (absent any dramatic technological changes), as rising consumption drains off excess capacity and the geographical concentration of reserves restores OPEC's power in the market.

"Energy intensity" continued to go down during 1988 -- a trend unlikely to reverse

Low prices over the past couple of years have caused only moderate increases in U.S. demand for energy. With an adjustment for abnormal weather in 1988, the ratio of energy use to GNP dropped another 1.4 percent. A steady underlying decline in this ratio is based in part on more efficient technology and partly on changes in the U.S. industrial product mix.

Many factors influence U.S. "oil vulnerability" as stocks and imports climb

U.S. oil imports have gone up by 50 percent since 1985 -- nearly an additional 2 million barrels per day. Yet the Free World as a whole now depends on OPEC production to satisfy only a bit more than 40 percent of its total demand (versus almost 70 percent in the 1970's); and this is a critical gauge in a global market. The OPEC worldwide share is headed back above 50 percent for the late 1990's; but the growing strategic petroleum stocks in this country, Japan, and the Federal Republic of Germany are now capable of supplying more than 5 million barrels per day for several months in an emergency.

Economic vitality is key to demand for petroleum, but U.S. oil output falls

GNP increased by about 4 percent during 1988, resulting in growth of domestic oil consumption at about half that rate. Most of the projected future increase is for industrial and farm diesel and jet fuel, but not for gasoline (thanks to increasing auto fuel efficiency). U.S. offshore oil production is expected to hold steady, yet overall output is seen falling from 8.2 million barrels per day in 1988 to 5.9 million barrels per day by the end of the century.

Natural gas production lags rising demand, with imports filling in the gap

A recent turnaround in U.S. demand for natural gas has resulted in growing domestic production; and its use in this country could expand by between 10 and 15 percent before 2000 -- to exceed 20 trillion cubic feet per year once again. Competition within the industry is being stepped up, and the chief market for added use of the fuel lies in generation of electricity. Net imports (mostly from Canada) would have to double during the 12-year period -- with perhaps 0.3 trillion cubic feet entering each year by then in the form of liquefied natural gas -- to meet peak demand during the heating season.

Electricity outstrips GNP as coal and gas bear heavier generation burden

Despite increasing efficiency in the use of electricity, its sales are projected in the *AEO* base case to rise a little more rapidly than GNP. In fact, electric power purchases by industry (especially for primary metals, chemicals, metal fabrication, and paper) would rise by a yearly average of 3.2 percent. With no newly ordered nuclear plants being counted on by 2000, fossil fuel plants must continue to provide most of the Nation's generating capacity. New construction of gas-fired combined-cycle plants after 1995 is expected to be especially significant.

A View Ahead

- World Oil Prices
- Energy Efficiency
- Oil Supply "Vulnerability"

World Oil Prices

Overall energy use in the United States increased by about 3.4 percent during 1988, the second year in a row for such growth. Nevertheless, U.S. energy prices continued to decline throughout 1988. With the demand-pressures of a strong economy (4 percent growth in real GNP) and of weather conditions that pushed parts of the natural gas and electricity generation-and-distribution systems to their maximum capacities, the decline in prices was clearly not caused by domestic market forces. Rather, this year's price declines were based on low prices in the international market for oil.

Imported oil prices, having recovered to more than $19 per barrel in July 1987 from a low of $11 a year before that, slid back down to around $13 by October 1988. On average, oil prices during the year were nearly 20 percent lower than in 1987.

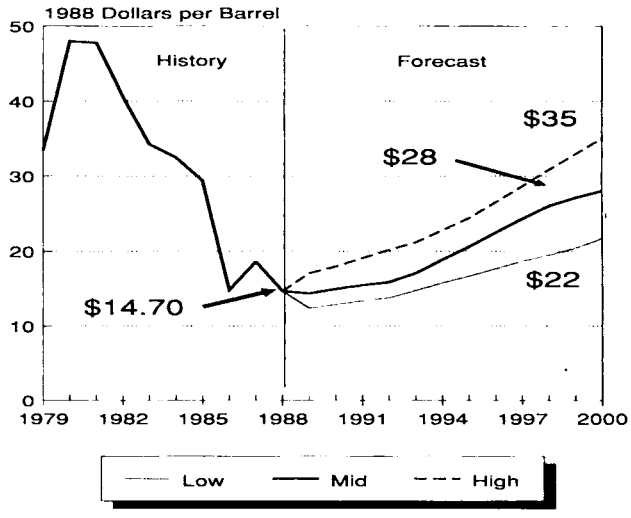
Petroleum remains by far the largest single source of energy in this country -- again satisfying more than 40 percent of the Nation's total demand during 1988. The fuel is substitutable in some degree for every other energy source, so the U.S. outlook for both production and consumption of energy across the board depends on what price oil will bring in the future.

Oil prices are influenced by a number of economic, technological, and political factors that may interact in unexpected ways. To account for these factors and to resolve their conflicting influences, EIA uses the personal computer-based PC-AEO Forecasting Model in developing the projections in this report (see note on Contacts page). Because the *Annual Energy Outlook* (*AEO*) is a *projection* rather than a series of outright *predictions*, it has customarily constructed a "base case" within a range of courses that EIA considers most likely at present. Figure 1 shows this range for average crude oil prices, expressed in real 1988 dollars per barrel delivered to U.S. refiners.

In the base case, prices remain below $20 per barrel until 1995 and then rise rather steadily to $28 per barrel by the year 2000. This trajectory is somewhat lower than the one used in the previous *AEO*, and comparisons with that and other more recent forecasts are summarized in the section of this report that begins on page 35.

Table 1 illustrates the effects that EIA is projecting in each of its three price scenarios upon domestic petroleum production, U.S. demand for oil, and the level of net imports implied by these alternative price assumptions for the years 1995 to 2000.

All Scenarios Point to Higher Oil Prices



Source: See Appendix D.

Figure 1. Alternative Assumptions for World Oil Prices, 1979-2000

OPEC's Future Influence Is Tied To Management of Excess Capacity

Stability of world oil prices has long depended on agreements of one sort or another to manage production capacity that exceeds current demand. Up until the 1970's, a group of large oil companies known as "the seven sisters" (Exxon, Mobil, Texaco, Chevron, Gulf, British Petroleum, and Royal Dutch Shell) controlled much of the world oil market and kept prices fairly steady. During part of this period the Texas Railroad Commission prorationed production in Texas (where much of the world's unused production capacity then existed) to match demand on a monthly basis. As excess capacity in the United States diminished, however, the capability to control the global market shifted to the Organization of Petroleum Exporting Countries (OPEC) -- which increased its share of the Free World supply to almost 70 percent in 1974 (Figure 2).

After several price shocks caused global demand for oil to plummet, some analysts doubted that OPEC could unilaterally set world oil prices. Standard economic theory suggests that cartels are naturally unstable because their producing members often have large incentives to cheat on both quotas and price; and, in fact, it was excess production by many OPEC members that led to some extreme price variations over the past several years.

Table 1. United States Petroleum Supply and Demand Under Alternative Assumptions

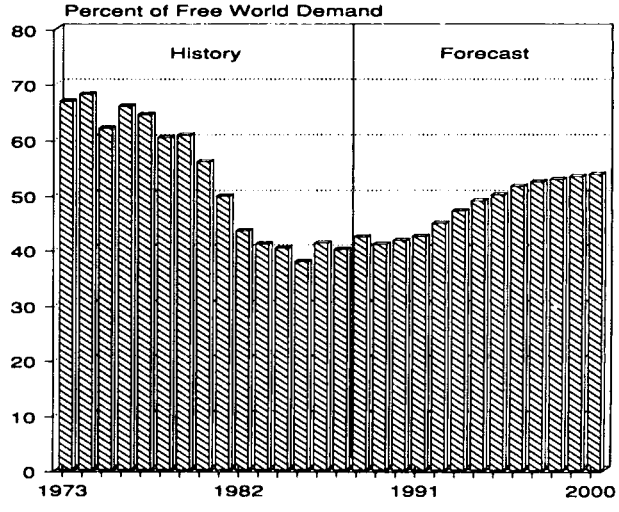
	1987	1988	1995 Low	1995 Base	1995 High	2000 Low	2000 Base	2000 High
World Oil Price (1988 dollars)	18.70	14.70	16.70	20.60	24.40	21.70	28.00	35.00
Real GNP Growth (average annual percent)	3.4	4.0	2.5	2.5	2.4	2.5	2.5	2.4
Production (million barrels per day)								
Crude Oil	8.35	8.18	5.79	6.17	6.79	5.15	5.89	6.77
Other Liquids	2.30	2.33	2.50	2.46	2.41	2.62	2.56	2.52
Total Liquids	10.65	10.51	8.29	8.63	9.20	7.77	8.45	9.29
Consumption (million barrels per day)	16.67	17.01	18.47	17.82	17.27	19.53	18.61	17.81
Net Imports (million barrels per day)	5.91	6.28	10.28	9.28	8.18	11.79	10.20	8.55

Note: Other Liquids includes natural gas liquids, processing gain, and other domestic production.
Source: See Tables A8, B8, C8, A11, B11, and C11.

In 1986, Saudi Arabia (which had long acted as the "swing producer" within OPEC) responded to continued excess production on the part of some members by bringing its own production back up to its originally assigned quota. As a result, prices dropped briefly below $10 per barrel for some types of crude oil. Again in late 1988, excess production by some members led Saudi Arabia to boost its production (even *exceeding* its quota for a time), and prices fell dramatically in response to the resulting excess of supply over demand.

Near the end of 1988 the OPEC ministers reached a new production agreement that was to go into force after the first of the following year. Nevertheless, if OPEC as a whole (or a single large producer, such as Saudi Arabia) is unwilling to adjust production downward when needed to stabilize prices in the future, the old pattern threatens to repeat itself so long as excess production capacity remains. Wide fluctuations in price can recur, as OPEC tries again and again to manage its own output; and the situation may persist until the mid-1990's (when OPEC may once more be selling enough oil to approach the limit of output it is capable of producing).

OPEC Resumes Dominant Role in World Market

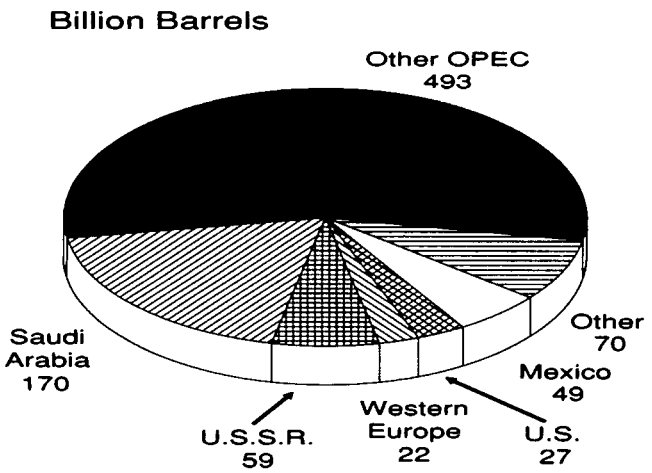


Source: See Appendix D.

Figure 2. OPEC Oil Production as Percent of Free World Demand

OPEC has difficulty in holding to individual production quotas that could maximize overall profits. Its problem in maintaining almost *any* target-level for its aggregate production is that the organization consists of countries with widely divergent social and economic problems and interests. Because of differences in cost structure, reserves (Figure 3), price expectations, and internal discount rates, there are inevitable conflicts in allocating total production. From time to time, this has lead to overproduction by OPEC.

OPEC Holds The Biggest Share of World Oil Reserves



Source: *Oil and Gas Journal*, December 28, 1987.

Figure 3. World Oil Reserves of Major Producers, 1987

The consequences of OPEC's internal squabbling have been obvious. When some oil prices jumped to the $40-per-barrel range around the beginning of the 1980's, worldwide demand fell and non-OPEC production increased. The combination was sufficient to push OPEC's market share back down from more than 60 percent to about 35 percent in only a few years. This is why it can be said that overpricing led to the current problem of overproduction.

The problem for OPEC has been deepened by another fact: when oil prices dropped again, demand did not rise as vigorously as it had earlier fallen. Relatively low prices over the past couple of years have caused only moderate increases in petroleum consumption, particularly in the United States and in the less developed countries. On the *supply* side, however, non-OPEC production continues to grow -- even though the rate of increase is slowing.

One explanation for the weak demand response is that governments in some countries that both consume and produce oil change their policies to counteract the effects of falling prices. For example, when prices are low, some nations outside OPEC cut taxes on their oil producers to shore up the profitability of marginal projects. At the same time, consumers in Europe have not had as much encouragement to consume more oil as might have been expected -- because taxes on petroleum products were raised in the face of declining prices. The likely result is that world oil prices will continue to be volatile and low for at least the next year or two. Looking to and through the next decade, on the other hand, excess production capacity around the world is bound to diminish as population expands and economic development and growth continue.

Technological Changes in Many Areas May Increasingly Affect Price

The economic forces that determine the supply and demand for oil include technological change in both the production and consumption of energy, the size of the resource base (which can also be affected by technology), and overall economic growth.

Improvements in the technology of finding and developing oil reserves have periodically played a major role in bringing additional oil supplies to market. This explains in part how world oil reserves grew from 550 billion to 810 billion barrels between 1978 and 1988 -- even though 155 billion barrels of crude were extracted from the earth during that period (see source, Figure 3). Continuing technological progress in the future is almost a given, but the pace cannot be certain. If advanced technology makes it significantly less costly to find and develop oil reserves, prices for petroleum could remain lower than otherwise would be the case.

Oil prices will also be influenced by the cost of developing natural gas resources, because sharper economic competition from that fuel tends to curb oil demand. The principal assignment for which oil and gas are competing at the moment is as a boiler fuel; and this market area is a large one, especially in Europe.

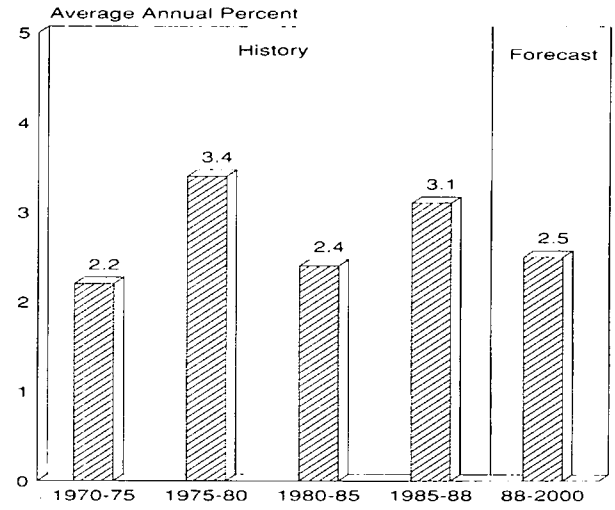
Finally, advancing technology is critical in determining how much energy of any sort is used for each unit of output. As Figure 4 shows, most nations have become more efficient in the use of energy during the past 15 years or so -- with the

exception of the developing countries. The change is sizeable enough to indicate a reduction in energy consumed per unit of output (i.e., energy intensity) that cannot be attributed solely to modifications to the industrial product mix.

Energy Efficiency

A projection of 2.5 percent growth in GNP for the United States between now and 2000 is entirely consistent with long-term trends (Figure 5); and economic growth and improvements in the standard of living both normally require that more energy be consumed. However, between 1973 and 1987, the total U.S. consumption of energy expanded by only 3.4 percent *in all* -- while GNP grew by 40 percent. As a result, the ratio of energy use to economic output declined. Since 1985, this downward trend of 2.1 percent per year in the energy-to-GNP ratio has moderated; but EIA still projects the ratio to decline at an average rate of 1.3 percent per year for the rest of this century (Figure 6). Decreased energy intensity is based in part on technological improvements in energy-using equipment and in part on price-induced conservation. It is evident now in *all* energy-consuming sectors.

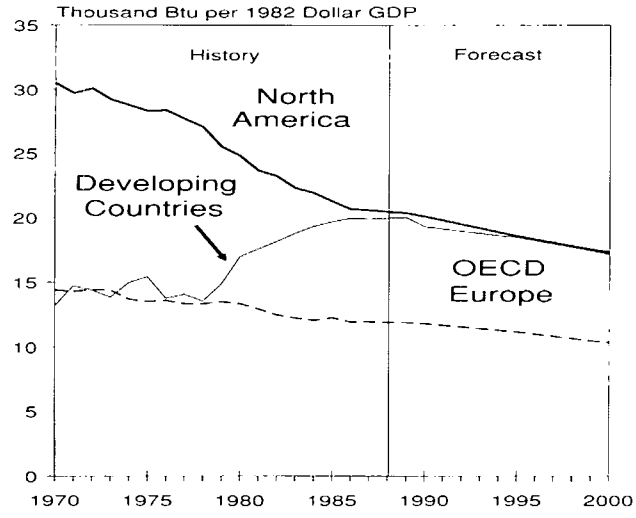
Future Economic Growth Lower Than Recent Years



Source: See Appendix D.

Figure 5. Average Annual Growth Rates for Real Gross National Product

Energy Efficiency Grows Throughout the World



Source: See Appendix D.

Figure 4. Energy Intensity in Selected Regions, 1970-2000

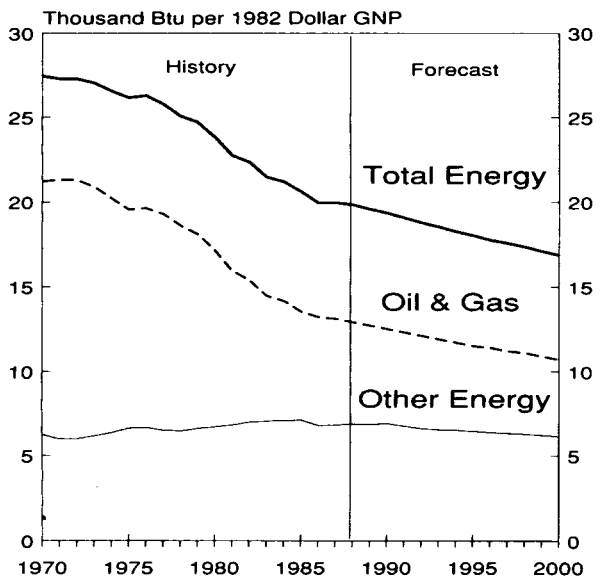
The year just completed involved several aberrations. High rates of growth in the industrial and transportation sectors during 1988 were tied largely to the revival of domestic manufacturing industries under a depreciated dollar and moderate domestic inflation. In addition, at least 0.8 percentage points out of the overall rise in energy consumption of 3.4 percent that *did* take place during the year could be attributed to an unusually cold winter (which boosted the normal consumption of all types of energy for space heating) and also a record hot summer (which spurred extraordinary use of electrical cooling equipment). (See EIA's October 1988 *Short-Term Energy Outlook* for discussion of weather's effect on energy use.)

Despite all the unusual circumstances (including "bargain" prices for oil), the U.S. economy's energy intensity went down by an estimated 0.6 percent during 1988 (Table A11). If weather effects are removed from the statistics, the decline was approximately 1.4 percent.

In the transportation sector, the efficiency of gasoline, diesel, and jet engines is improving constantly. This should hold energy consumption growth there to about 0.5 percent per year between now and 2000. Similarly, in the case of residential and commercial energy use, the greater number of

households, additional commercial floor space, and growth in the number of energy-using devices over the next dozen years can be offset by improved energy-efficiency and energy management measures. The combination of these two sectors is projected in the base case to step up energy consumption at a rate of only 0.6 percent per year.

Technology, Conservation, Sectoral Shifts Reduce Energy Intensity



Source: See Appendix D.

Figure 6. U.S. Energy Intensity, 1970-2000

Total energy requirements for the industrial sector grow in the *AEO* base case at an average of 0.8 percent annually -- at the same time overall manufacturing output keeps up with GNP growth (i.e., about 2.5 percent per year). This corresponds to EIA's expectation of more efficient industrial facilities, better process control equipment, and -- to a small extent -- industrial use of cogeneration (which produces electricity by using waste heat generated from other manufacturing, heat, and power activities). To a significant degree, however, improved energy intensity also reflects a shift in the Nation's product mix toward goods that require less energy per dollar of final product -- or toward production that adds more value for the same quantity of energy input. A typical example is the chemical industry, which now requires less electricity than heretofore per dollar value of output -- largely because such products as specialty chemicals are expanding and the outlook for growth in inorganic chemicals is much more modest.

The ratio of oil and gas use to GNP has declined even more rapidly than the total energy-to-GNP ratio has. During the forecast period, this measure of U.S. oil and gas intensity now looks as if it could continue to decline at about 2 percent per year, reflecting both higher efficiency and the continued consumer preference for electricity in many sectors. At the same time, however, the rising consumption of oil and gas for electricity generation and the continued growth in demand for petrochemical products will help to slow down the future rate of decline in this ratio.

Concerns about energy security, the U.S. trade balance, and the environmental impacts of all energy production and consumption promise to reinforce the underlying economic trend toward greater efficiencies. Continued progress in getting the most out of energy is a basic fact in today's outlook that must not be ignored -- although care should also be taken not to assume that improved energy efficiency is a solution in itself to every energy-related problem that can be foreseen or conjectured.

Oil Supply "Vulnerability"

U.S. petroleum consumption was estimated at 17 million barrels per day for 1988 (Table A8). It is projected in the base case to rise to about 18.6 million barrels per day for the year 2000. By that time, domestic petroleum production is projected to be more than 2 million barrels per day lower than it is now. As a result, net imports of petroleum are expected to rise steadily -- from about 6.3 million barrels per day in 1988 to about 10.2 million barrels per day in the year 2000.

In the base case, U.S. "dependency" on imported oil thus rises from about 37 percent today to 55 percent over a 12-year period. This country would exceed the benchmark of 50 percent dependency by 1994. In the higher and lower price cases, import dependency by 2000 ranges between 48 and 60 percent.

U.S. oil imports have already moved up to a level that is 50 percent above what it was just 3 years ago. Thus, it is appropriate to ask just how vulnerable the United States is becoming to future supply disruptions. Unfortunately, there is no clear and simple answer.

Stockpiles and Interdependence Moderate Threat to Security

Although U.S. imports have risen quickly, the Nation's "vulnerability" has not increased nearly as much. Two primary factors are responsible for this: (a) the existence of a unified, competitive global market, and (b) growth in various national stockpiles of petroleum.

In an essentially free market, international changes in price and supply cannot easily be isolated to a single country. The dependence on Middle East oil of the Free World overall is a more meaningful indicator of potential vulnerability than U.S. dependence on oil imports generally -- or even this country's dependence on OPEC oil alone. In fact, OPEC's share of the entire Free World market has also been rising recently; but even in this year's projections through the year 2000 it promises to stay well below the record high of about 68 percent that it reached in 1974.

Because total U.S. oil imports are bound to keep going up, this country's specific reliance on supplies from OPEC (which controls an overwhelming percentage of the world's oil reserves) can be expected to increase as well. The Nation's first line of defense against the threat of future oil shocks lies in its Strategic Petroleum Reserve. About 50,000 barrels of oil a day continued to be directed into SPR during 1988 (Table A8). However, with imports higher than they were a year ago, the current SPR stocks of more than 550 million barrels are adequate to displace imports *totally* for a shorter period now (88 days for 1988 versus 90 days for 1987); but this popular rule of thumb, which was formalized as a policy objective in the current International Energy Agency agreements, is itself not a totally reliable gauge of vulnerability either. In this country, a readjustment in demand could take place quickly in response to changing prices because of the Nation's fuel switching and conservation potential.

Allies of the United States are also building strategic reserves of oil. Apart from the U.S. ability to draw down its SPR at a rate of 3 million barrels per day (about half of current imports), it is estimated that Japan and West Germany can now draw approximately 2 million barrels per day from their own stocks for several months. This total available supply of about 5 million barrels per day over several months would greatly reduce the adverse effects of any disruption that might take place. It should even be adequate to discourage some countries from attempting to use such a disruption to achieve political objectives.

Given the present excess in production capacity around the world, a new disruption would have to be very severe in order to make a major impact. As evidence of this, the 8 years of armed conflict between Iran and Iraq (both OPEC members) produced relatively little upward pressure on prices that could be detected. And, in fact, when a cease-fire in that war was declared, this event happened to be accompanied by a brief *rise* in prices instead of a drop.

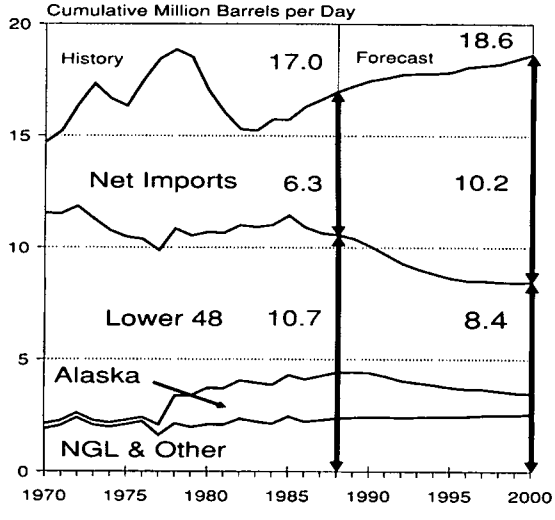
Outlook for Specific Fuel Markets

- U.S. Petroleum
- Natural Gas
- Electricity
- Coal

U.S. Petroleum Markets

U.S. petroleum consumption of 17 million barrels per day during 1988 represented an increase of about 2.0 percent for the year (Figure 7). In other words, the rate of growth in oil use was just half the percentage rise in GNP. Higher use of petroleum resulted partly from the weather's effects on demands for heating oil, propane, and electric utility use; but increased consumption of motor gasoline, highway diesel, and jet fuel accounted for more than three-fourths of the demand increase that occurred.

Growing Demand and Falling Production Point to Higher Imports



Source: See Appendix D.

Figure 7. Petroleum Supply and Consumption, 1970-2000

Although growth in demand for transportation fuels may tend to slacken in 1989 (along with the economy and in response to higher prices), this consuming sector will tend to dominate changes in U.S. oil requirements for the next few years. The only other factor in the near term worth mentioning is the demand for hydrocarbon feedstocks to support the continued recovery of this country's export industries.

In the longer run, EIA now projects that U.S. use of diesel and jet fuel will continue to rise, but that gasoline consumption will rise initially and then return to almost current levels by the year 2000. Improvements in mileage-per-gallon for new gasoline-powered vehicles over the past decade should raise the *average* efficiency of the U.S. road fleet steadily -- nearly offsetting the increase in vehicle-miles traveled. The biggest *percentage* increase among petroleum fuels is expected to be for residual oil used in generating electricity, but this is not as significant in absolute volume.

Although world oil prices in 1988 nearly fell back to 1986 levels (averaging about $14.70 per barrel), market response by purchasers in this country was smaller than it was a few years ago when prices jumped. On the production side, however, the revival in domestic drilling for both oil and gas that had begun in the second half of 1987 halted. The reason total crude oil production fell only slightly was that some long-anticipated but temporary increases in Alaskan production were finally realized, while lower costs for well-servicing and maintenance in the Lower 48 States helped sustain the profitability of older producing fields.

The lack of demand response to recently lower world oil prices influenced the EIA's current "Year 2000" projection. In the base case, EIA now foresees an average growth rate of less than 1 percent in petroleum consumption, even while the U.S. economy as a whole is growing by 2.5 percent per year. This would lead to consumption of 18.6 million barrels per day by 2000. In analyzing alternative possibilities, EIA calculated that a world oil price in 2000 that was about 25 percent (or $6 per barrel) lower would raise U.S. demand for petroleum by only 5 percent (900,000 barrels per day); a 25-percent increase in price would lower demand by a comparable 800,000 barrels per day.

Falling U.S. Oil Production Tied To Resource Limits, Technology

In 1988, the Nation once again produced less crude oil than it did in the previous year -- a decline in output of about 2 percent. Coupled with higher domestic demand, this means that net oil imports rose by about 400,000 barrels per day in that year. The imported fraction of total U.S. demand would then be 37 percent -- only slightly higher than projected last year, but higher than at any time since 1980.

The "windfall profits tax" on crude oil was repealed by the Trade Expansion Act of 1988, but this had little or no immediate effect on drilling or production because average oil prices were already below the statutory minimum in categories to which the tax had applied. Domestic production has been declining since the oil price collapse of 1986, and it is expected to continue going down through the end of the century.

Total crude oil production is projected to fall from 8.2 million barrels per day in 1988 to 5.9 million barrels per day in 2000, an annual decline rate of 2.7 percent. The biggest declines are from the onshore producing regions of the Lower 48 States, while production from the offshore regions remains steady. Although rising oil prices in the last years of the forecast lead to a very small rebound in production from the Lower 48 States, a long-expected and steady drop off in production from Alaska contributes to the overall decline. The outlook for supplies of natural gas liquids (NGL's), which currently account for about 15 percent of domestic petroleum production, helps to moderate the decline. NGL's, including propane, butane, and other liquid fuels extracted in the process of producing pipeline-quality natural gas, will increase by 0.3 million barrels per day by 2000, as gas production grows throughout the forecast period.

The outlook for crude oil production is influenced by estimates of undiscovered recoverable resources underlying the projection. These estimates are subject to considerable uncertainty. The undiscovered recoverable resources used here are derived from the published figures of the United States Geological Survey (USGS). The EIA projection utilized the mean undiscovered recoverable resources estimate. However, a wide range of volumes may be realized as recoverable resources. Consequently, based on geologic uncertainty surrounding the assumed level of undiscovered recoverable resources, the realized path of future crude oil production may be lower or higher than that presented in the forecast.

The USGS resource estimates are based on assumptions including current technology, economic conditions consistent with the time of estimation, and accepted production practices. Current literature suggests that greater developmental intensity of producing fields through additional infill drilling will increase ultimate recovery. The extent to which greater infill drilling is occurring above previous levels as an established industry practice is uncertain. An increase in overall recovery would lead to an eventual increase in production, yet the timing of the impact on production is itself uncertain. Thus, any stimulation of production through greater resource recovery, if realized, is not expected to significantly alter the forecast through 2000.

Foreign Supply of U.S. Petroleum Seen at 55 Percent by 2000

Given the projection for growing petroleum demand and declining domestic production, a conclusion of higher petroleum imports in the future is difficult to avoid. In this year's outlook, net petroleum imports of crude oil and refined product (i.e., imports minus exports) are forecast to increase from 6.3 million barrels per day in 1988 to 10.2 million barrels per day in 2000. In comparison, the highest annual level of net imports was reached in 1977, at 8.6 million barrels per day. The forecast for 2000 reflects an import dependence (net imports divided by total petroleum demand) of 55 percent, up from 37 percent in 1988. Historically, import dependence had peaked in 1977, at 46.5 percent.

Increased petroleum imports are forecast to come mainly in the form of crude oil, assuming no major changes in the relative economics of refining petroleum products in the United States and in the other major refining centers of the world. The outlook for stable product trade patterns could be altered as a consequence either of major changes in the relative mix of products demanded in the United States or abroad or of additional refining costs imposed by the need to accommodate environmental concerns.

Demand for Transportation Energy Continues to Dominate U.S. Oil Use

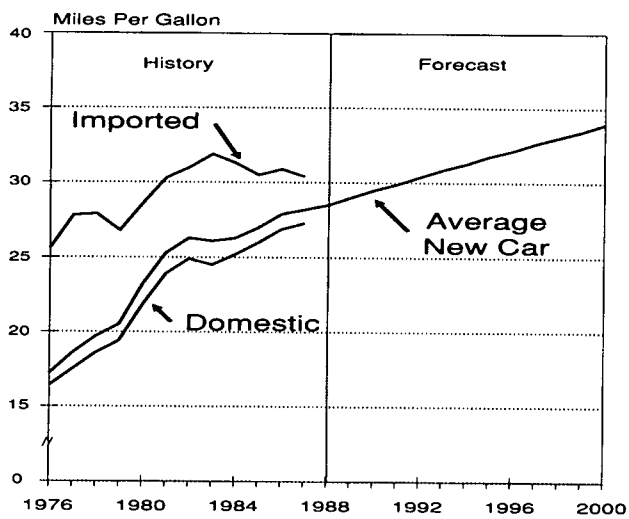
Most of the projected increase in total petroleum use is for transportation uses -- diesel and jet fuel, but not gasoline. The transportation sector relies almost entirely on petroleum products, accounting for about 63 percent of the Nation's petroleum use. Improved fuel efficiency of road vehicles is expected to nearly compensate for the growth in demand resulting from increases in personal and freight travel, especially for gasoline-powered vehicles. In fact, the base case forecast in 2000 for total transportation energy use (23.2 quadrillion Btu) is only about 6 percent higher than the consumption level in 1988, despite a 28-percent increase in vehicle-miles traveled (VMT) by personal vehicles and a 32-percent increase in vehicle-miles traveled by freight trucks over the same period.

Personal travel by autos and light trucks is forecast to increase at an average annual rate of 2.1 percent between 1988 and 2000, about the same rate as growth in passenger VMT that occurred between 1970 and 1987. (Data on transportation are taken from the U.S. Department of Transportation; see sources for Figure 8 in Appendix D.) Since the population is forecast to increase at an average annual rate of 0.7 percent by 2000, per capita VMT is expected to continue to increase over the forecast period, reaching a level about 17 percent higher than the 1988 level by 2000. Recent aggregate VMT per capita data do not indicate a saturation point in personal travel has been reached and no such saturation is assumed in the forecast.

Trucks are expected to account for an increasing share of highway fuel use (33 percent in 2000 versus 29 percent in 1988). As a part of this trend, diesel-powered trucks are being used increasingly for short-haul activities in place of gasoline vehicles, and long-haul activity is growing with the economy. Consequently, diesel fuel oil use is expected to increase by almost 25 percent between 1988 and 2000. Although economic growth implies more freight demand, the intensity of this demand appears to be steadily decreasing for some industries such as chemicals and primary metals, as their respective mixes of commodities produced shift over time.

Improved automobile fuel efficiency is the key to understanding the slightly lower gasoline demand over the forecast (Figure 8).

Automobile Fuel Efficiency Grows at a Slower Pace Than in 1970's



Source: See Appendix D.

Figure 8. New Car Fuel Efficiency, 1976-2000

New car fuel efficiency is estimated to increase at an average annual rate of about 1.5 percent, from about 28.5 miles per gallon in 1988 to about 34 miles per gallon in 2000 -- about the same rate of improvement between 1982 and 1987. This rate of efficiency improvement is substantially below the annual rate accomplished in response to the sharp gasoline price increases of the 1970's. In fact, gasoline is cheaper in 1988 than it was in 1972 (in real terms), the last year before the Arab oil embargo.

Two additional factors related to improved fuel efficiency -- that is, beyond the federally mandated Corporate Average Fuel Efficiency (CAFE) standards -- include the mix of domestic and foreign cars and the effect of gasoline prices on the choice of cars. The average fuel economy of new cars is a weighted average of both domestic and import cars. In 1976, cars imported into the United States were, on average, about 32 percent more fuel efficient than the average domestic cars (U.S. Department of Transportation). The increasing import market share was an important factor explaining improved average fuel efficiency through 1980. Since 1980 the import market share has been relatively stable, varying between 26 and 30 percent, and the disparity between the import and domestic car average fuel efficiency had been reduced to about 11 percent by 1987. Also of significance are changing consumer preferences for light trucks and four-wheel-drive vehicles, which are not counted in the new car mileage statistics and which generally have lower efficiency.

In the last year or so the rate of improvement in new car miles per gallon has slowed considerably. It is thus reasonable to consider the possibility that the new car fleet average fuel efficiency for 1989 and later years may not increase significantly as long as gasoline prices show no signs of increasing. In the forecast, if there were no increase in new car efficiency above the 1988 level, average fleet efficiency of all cars would still rise above the 1988 level, but an additional 400,000 barrels of gasoline would be consumed per day by the year 2000.

Freight energy forecasts reflect both improved freight vehicle efficiencies and reduced freight intensities. Average freight truck efficiencies are steadily improving over time, but at a much slower rate than that for the auto fleet. Between 1988 and 2000, average freight truck fuel efficiency is assumed to increase by 13 percent. Vehicle-miles traveled by freight trucks, however, is projected to grow by 32 percent over this same period. In many industries shifts in product mix towards less bulky commodities have reduced freight needs considerably in recent years and this trend is reflected in the forecast. For example, the freight transport requirements of the chemical industry are assumed to increase about 20 percent less by 2000 than output in the chemical industry.

Air Traffic Rise Puts Jet Fuel Among Fastest Growing Commodities

About 8 percent of domestic petroleum consumption is in the form of jet fuel. Between 1988 and 2000, jet fuel demand is projected to grow by 1.4 percent per year. This growth rate is considerably below jet

fuel consumption growth in recent years. The large growth in demand in recent years has been caused by a vigorous rise in both domestic and international airline traffic. Since 1985, domestic passenger traffic (revenue passenger-miles) has risen by over 7 percent per year, driven primarily by a 3-percent annual increase in real disposable income and declining real ticket prices (U.S. Department of Transportation). Ticket prices are not assumed to decline further over the forecast.

Domestic freight and international passenger traffic have grown even faster than domestic passenger traffic. Since 1985, domestic freight traffic (revenue ton-miles) and international passenger traffic have grown at rates approximately twice that of domestic passenger traffic.

The size and age of the domestic airline fleet also have an important effect on fuel consumption. Of the nearly 3,700 airplanes registered with U.S. airlines at the end of year 1987, over 25 percent were 20 years old or more. This aging of the U.S. fleet has occurred because there has been surprisingly little incentive for the airlines to purchase different aircraft. As a result of airline deregulation, existing, smaller aircraft were needed to fit into the newly formed "hub and spoke" networking of interconnecting flights. Because of the networking system, and because jet fuel prices have been quite low since 1983, the airlines have found that the older, smaller, and less fuel efficient planes are still cost effective.

Yet, with the increasing cost of maintaining an older fleet, and the prospect of a growing international market, a record number of new aircraft orders have been placed this year. By December 1988, over 400 orders for new aircraft had been placed, with many more reserved with an option to buy. Because of the need to accommodate the increase in passenger traffic, given the existing air traffic capacity shortage, many of these orders are for larger planes. Since these larger planes embody some of the most recent technology and carry nearly 25 percent more passengers than the planes they would replace, fuel efficiency gains should be evident as these new planes are introduced into the fleet.

One of the latest major advances in fuel efficient technologies, the "propfan" engine, offers a 40-percent improvement in fuel efficiency but no aircraft using the engine have entered commercial service. Nonetheless, these engines could be retrofitted into current planes if fuel prices were to increase by a significant amount.

Electric Utilities Increase Oil Demand To Meet Increased Generation

Electric utility consumption of petroleum is projected to increase at an average annual rate between 5 and 6 percent over the forecast horizon, resulting in a total gain of over 0.5 million barrels per day. Much of the increase occurs in the post-1995 period, as continued growth in electricity demand is expected to lead to fuller utilization of existing petroleum-fired plants. Greater use of petroleum results primarily because of increased demand, rather than any shift in market share based on the price of oil relative to natural gas in specific regions. However, the use of this oil is an inevitable consequence of the need for additional generation in regions where much of the current surplus capacity for electricity generation is oil-fired. Currently, this capacity is used more heavily in winter when natural gas is not available. If the natural gas market should fail to match fuel oil prices, then oil consumption could rise further.

Industrial Oil Use Driven by Feedstock Demand and Diesel Use in Agriculture and Construction

The total amount of petroleum consumed in the industrial sector in 1988 was approximately 4.3 million barrels per day or 8.5 quadrillion Btu, which represents about 39 percent of total industrial sector energy consumption (Table A2). The largest single use is for raw materials (feedstocks), for which liquefied petroleum gases and petrochemical feedstocks are used primarily to produce plastic resins. Together, these fuels comprise 2.4 quadrillion Btu, which is almost 30 percent of the industrial petroleum consumption. These levels are projected to increase to about 3.2 quadrillion Btu by 2000, at an average annual growth rate of over 2 percent. This rate of growth is less than that of the chemical industry over the same forecast period, so that the feedstock consumption per unit of output declines, reflecting both a product mix effect (from commodity chemicals to more specialty chemicals) and an increase in the efficiency of turning raw materials into final products.

Distillate consumption in the industrial sector in 1988 was 1.4 quadrillion Btu, which was about 16 percent of total industrial petroleum consumption (Table A2). Only a small amount of this distillate was consumed for heat and power in the manufacturing sector. Most of it was consumed in the form of diesel fuel for a variety of off-highway uses (including tractor and truck fuel) in agriculture, construction, and mining. Distillate consumption is forecast to increase at an average annual rate of 1.3

percent to a level of approximately 1.6 quadrillion Btu in 2000. This largely reflects an increase in the agricultural output during the forecast.

Residential/Commercial Oil Use Shows Little Change Over the Forecast

Residential sector distillate oil consumption (including kerosene), reached about 1.2 quadrillion Btu in 1988 and represented only about 12 percent of the total residential energy consumption (Table A2). Distillate oil is used almost exclusively for space heating and is mostly used in the Northeastern States. Its use has decreased dramatically in the past decade for two reasons: space heating is generally most affected by conservation improvements, and there has been a long-term trend away from the use of distillate oil which was heightened by the strong increases in oil prices in the late 1970's and early 1980's.

Residential distillate consumption (heating oil and kerosene) is projected to continue to decrease throughout the forecast period at an annual rate of about 2 percent; by 2000, consumption is expected to fall to about 0.9 quadrillion Btu.

In the commercial sector, total petroleum consumption accounted for about 15 percent of total commercial energy use in 1988. The forecast level of commercial sector oil use remains at about the 1988 level of 1.0 quadrillion Btu over the entire forecast, as slight increases in distillate oil consumption are expected to compensate for reduced residual oil consumption.

Refinery Costs Will Be Influenced Increasingly by Environmental Concerns

The domestic petroleum refining industry is expected to face major challenges during the next decade from the operational and capital investment requirements that will be imposed by a continuing shift in the mix of petroleum products demanded, as well as by increasingly stringent requirements on product quality.

Through much of the late 1970's and early 1980's, refiners had to adjust to many factors: changing and growing product demand, changing sources and qualities of crude oil, new environmental restrictions (placed both on the quality of final products and on refinery operations), and the end of price controls on crude oil and products. The profitability of the industry may have been affected even more during this period by changes in the level and volatility of crude oil prices (with price increases leading to lower refinery profits, and decreases to higher profits).

On the environmental front, the industry is completing its phaseout of octane-enhancing lead additives because of their health hazard (especially for young children) and negative effects on the catalytic converters placed on newer automobiles to control auto emissions. In December 1987, maximum lead levels were set by the Environmental Protection Agency (EPA) at 0.1 grams per gallon of leaded gasoline. Total lead use will continue to decline under the current standard as older vehicles are retired. Apart from replacement of lead, refineries will still have to meet increasing octane requirements, as newer and higher performance engines boost the demand for premium fuels.

The challenge of supplying the growing demand for high-octane gasoline blending components is increased further by health concerns relating to the use of butane and pentane -- high-octane blendstocks produced by refiners at relatively low cost and used to increase the volatility of gasoline. To overcome vapor lock problems associated with the excessive use of butane, especially in the summer, refiners also use other, more expensive octane-enhancing compounds (specifically the aromatic compounds). These lighter hydrocarbons, including butane, combine with nitrogen oxide emissions and sunlight to promote local ozone formation. Alcohol blends, which can raise octane without contributing to the ozone problem, still appear to be an expensive alternative and present additional problems with transportation, storage, and engine wear. Additional environmental challenges for refiners are presented by concerns about the cancer risks of aromatic blends and the role of nitrogen oxide and sulfur dioxide emissions in the formation of acid rain.

The quality of diesel fuel is coming under greater environmental scrutiny, too. Beyond current standards and goals for particulate emissions from diesel vehicles, EPA is studying the costs and benefits of further restrictions on the sulfur and aromatic content of diesel fuel. Sulfur content is related to the formation of sulfur dioxide. Sulfur compounds may be removed at the refinery or by modifying diesel engines. Doing the job at the refinery would increase the cost of fuel production, but, at the same time, would help vehicles meet other particulate standards, thus reducing the need for efficiency-dampening traps on diesel engines.

Domestic Oil and Gas Producers' Financial Performance Likely to Improve

The profitability of domestic oil and gas producers fell throughout the early 1980's in the face of declining oil prices and was severely affected by the oil price collapse in 1986. The small oil price recovery in 1987 contributed only modest and short-lived relief to severe downward profit pressures, and the renewed slump in world oil prices in 1988 has worsened the situation again.

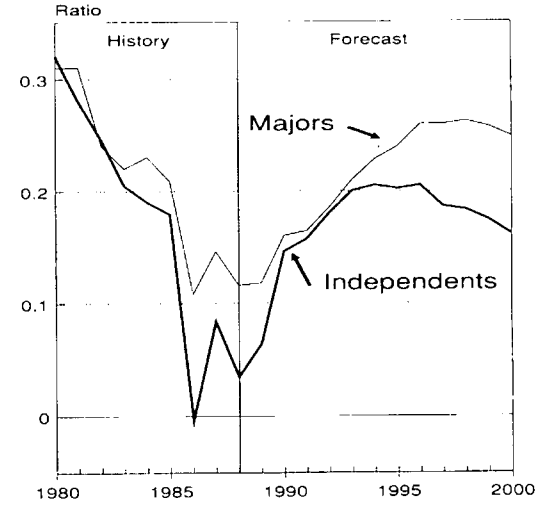
Amidst the turbulence in world oil markets in recent years, the major petroleum companies have tended to fare better in their domestic oil and gas operations than the independents. The independents' greater reliance on external financing, which served to increase their debt load, was one of the reasons they did not recover as well as the majors. ("Majors" are defined as the 22 large energy companies that report to EIA's Financial Reporting System (FRS). The results for FRS companies shown here represent information on their domestic oil and gas extraction segment. "Independents" are all other oil and gas companies. The financial results for the independents are derived from published financial information on publicly traded companies.)

An indication of the relatively poor financial condition of the oil and gas sector in recent years can be seen from the ratio of cash flow to net property, plant, and equipment (PP&E) (Figure 9). For the major petroleum companies, this ratio fell by 30 percent from 1985 to 1987 and for the independents the ratio fell by 53 percent. However, the forecast indicates that in the early 1990's, both groups will experience cash flow ratios that equal or exceed those of 1985. The ratio of cash flow to net PP&E increases initially as cash flow, responding directly to higher oil prices, increases more rapidly than expenditures. By the late 1990's, rising investment catches up, causing industry capital assets then to increase more rapidly than cash flow.

A substantial portion of the increased cash flow is forecast to be directed to exploration and development expenditures (Table 2). Industry drilling and equipping expenditures are forecast to increase from a low of $9.1 billion in 1988 to about $32 billion in 1995 and to $57 billion in 2000 (all in 1988 dollars). Capitalized exploration and development expenditures, which is a broader measure than drilling and equipping expenditures, is forecast to increase at a similar rate.

Historically, the independent petroleum companies have tended to expand their drilling efforts at a much more rapid pace than have the majors when oil prices rise and, conversely, contract their drilling more steeply in periods of oil price decline. This tendency is carried forward in the forecast share of expenditures for the independent petroleum companies. The independents' share of drilling and equipping expenditures in 1988 was 52 percent (Table 2). With oil prices rising in real terms, the independents will increase their share of drilling and equipping expenditures to 58 percent by 2000.

Investment Growth Offsets Effect of Higher Oil Prices on Profitability



Source: See Appendix D.

Figure 9. Ratio of Cash Flow to Fixed Assets for Oil Producers, 1980-2000

Table 2. Income and Investment in the U.S. Oil and Gas Industry

	1985	1986	1987	1988	1989	1990	1995	2000
Revenues and Cash Flow								
Revenues								
Billion 1988 Dollars	157.4	87.1	95.5	79.7	78.1	89.4	119.2	167.3
Index (1985 = 1.00)	1.00	0.55	0.61	0.51	0.50	0.57	0.76	1.06
Ratio of Internal Cash Flow to Net PP&E[a]								
FRS Companies[b]	0.209	0.108	0.146	0.116	0.118	0.160	0.239	0.248
Independents[c]	0.179	-0.004	0.084	0.035	0.064	0.146	0.202	0.161
Total	0.194	0.052	0.116	0.077	0.092	0.153	0.218	0.195
Oil and Gas Investment								
Total Spending on Oil and Gas Drilling/Equipment of Wells (billion 1988 dollars)								
FRS Companies[b]	11.4	6.9	4.1	4.5	6.0	7.8	13.8	24.3
Independents[c]	14.6	7.4	5.3	4.7	7.0	9.7	18.4	33.1
Total	25.9	14.3	9.5	9.1	12.9	17.5	32.2	57.4
Total Capitalized Exploration and Development Spending[d] (billion 1988 dollars)								
FRS Companies[b]	24.5	12.5	10.7	8.6	11.5	15.0	26.7	46.9
Independents[c]	29.6	12.2	7.5	9.0	13.4	18.7	35.3	63.6
Total	54.0	24.7	18.2	17.6	24.9	33.7	62.0	110.4

[a]Net income plus noncash charges divided by net value (original cost less accumulated depreciation) of property, plant, and equipment (PP&E).

[b]FRS companies are those major energy companies reporting financial information to the Energy Information Administration on Form EIA-28. These include the major U.S. integrated oil companies and the major U.S.-based multinational oil companies.

[c]Independents represent all companies engaged in domestic oil and gas extraction other than the FRS companies. The financial results for this group are derived from published financial information on publicly traded companies.

[d]Includes capitalized expenditures associated with drilling wells, unproved lease acquisition,lease and production equipment.

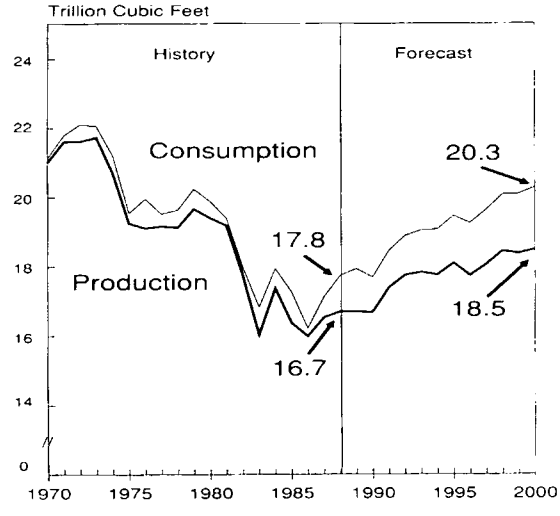
Source: See Appendix D.

Natural Gas Markets

Upturn in U.S. Gas Consumption Is Expected to Continue

Consumption of natural gas increased during 1987 and again in 1988, to 17.8 trillion cubic feet, marking the start of a trend that is expected to continue through at least the next decade. The use of natural gas in the United States had generally been declining since 1973, despite small increases in some years, as the demand for gas dropped from about 22 trillion cubic feet in 1972, to 16.2 trillion cubic feet in 1986 (Figure 10). The recent turnaround in demand has been paralleled by domestic production. By 2000, annual consumption of natural gas in this country is projected to climb to about 20.3 trillion cubic feet, or about the same as it had been in 1979. But, production is projected to increase at a slightly slower rate than demand, with the result that net imports of gas will more than double to 2.3 trillion cubic feet by the end of the century. The natural gas contribution to total energy consumption is forecast to change little from the 23-percent level for 1988.

Steady Growth in Gas Markets



Source: See Appendix D.

Figure 10. Natural Gas Consumption and Production, 1970-2000

Electric Utilities Lead Rise in Gas Use, But Industry Remains Top Consumer

The electric utility sector accounts for virtually all of the projected rise in total consumption of natural gas, more than offsetting small decreases by the residential sector (Figure 11). Only very minor increases are expected in gas used by the commercial and industrial sectors (including lease and plant fuel). No change is expected overall for transportation uses (essentially, pipeline fuel). Gas-powered road vehicles are not expected to have any significant impact on total demand before 2000.

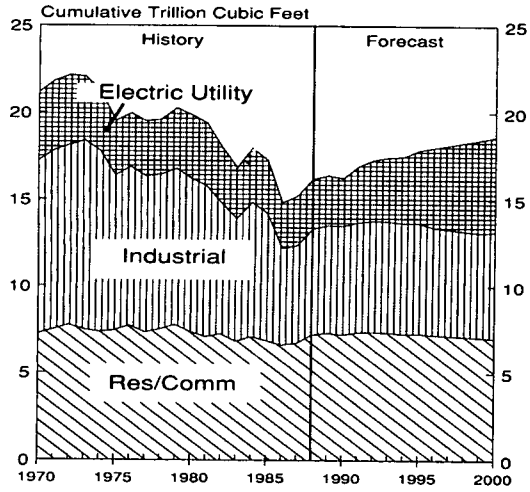
Industrial sector activities account for the largest share of gas used in this country -- 40 percent in 1988, including lease and plant fuel use (Table A9). The industrial sector will continue as the largest sector through 2000, although the industrial share will shrink to 36 percent. Total industrial use by 2000 is forecast to nearly match the 1988 level, reflecting the net outcome of two divergent trends: declining gas use in manufacturing activities and rising use in cogeneration activities.

Natural gas is the major fuel consumed in the industrial sector (Table A2). Its consumption of 7.2 trillion cubic feet in 1988 represented about 34 percent of all industrial sector energy consumption. About 1 trillion cubic feet of this was for lease and plant fuel consumption, while another 0.6 trillion cubic feet was used as a raw material, primarily for organic chemicals (particularly fertilizers). Most of the remaining consumption of natural gas was for heat and power in the manufacturing sector. Only smaller amounts are currently attributable to cogeneration of electricity in the manufacturing sector and for various uses in agriculture, construction, and mining. Despite the outlook for solid economic growth, a shift in demand away from those specific industries that use more gas and continued average efficiency gains with new investments over time point to declines in industrial demand for heat and power. Offsetting this decline, however, is an outlook for the increased use of gas to generate electricity both for self use and for sale back to electric utilities (see discussion on nonutility generation, page 26).

The electric utility sector is expected to be the fastest growing market for natural gas (Table A9). In 1988, electric utilities accounted for 16 percent of total gas use; by 2000, this share increases to 27 percent, as utilities displace the residential sector as the second largest user of natural gas. Strong growth in total demand is expected through the early 1990's, almost exclusively as a consequence of increased gas use in existing gas-fired plants by electric utilities. By 1995, utility use of gas will

increase almost 40 percent, to 3.9 trillion cubic feet. Additional growth between 1995 and 2000 will be nearly as significant, as increasingly competitive natural gas pricing and the growing investment in combined-cycle generating technologies by electric utilities continue to push demand for this fuel upward. Between 1988 and 2000, additions of combined-cycle plants using natural gas come forward to meet 34 percent of the utility industry's total need for new generating capability in that period (Table A6).

Most New Growth in Gas Demand Seen Coming From Utility Sector



Source: See Appendix D.

Figure 11. Natural Gas Consumption by End Use, 1970-2000

Conservation, Competition Restrain Greater Residential Use of Gas

In the residential sector, natural gas consumption in 2000 is forecast to be 4.3 trillion cubic feet, about 6 percent lower than it had been in 1988 (Table A9). Its primary use in this sector is for space heating. Although natural gas currently accounts for about 50 percent of energy use by residential users (more than heating oil and electricity combined), the preference for electric-powered heating systems in new homes, the greater efficiency of new gas heaters, and ongoing upgrades of old gas systems all combine to restrain total demand growth for this fuel. For existing homes, gas furnaces undergo a normal replacement with age that currently can result in an upgrade of efficiency from around 50 percent to as high as 80 or 95 percent. This represents a continuing opportunity for the conservation of natural gas and particularly for conservation in the use of space heating fuels. Natural gas will still remain the largest energy source in the residential sector, but its share falls to about 46 percent by the year 2000.

In the commercial sector, natural gas use remains almost constant through 2000, at 2.7 trillion cubic feet. This constancy is the result of two offsetting trends. First, a growing share of new construction in total commercial floor space tends to increase the average intensity of natural gas use. (According to the EIA's 1986 Nonresidential Buildings Energy Consumption Survey, natural gas use per square foot of new commercial floor space is greater than use per square foot of older commercial floor space. The same is true for electricity.) However, offsetting this trend toward higher energy use intensities in new commercial space are the energy conservation effects that higher energy prices have on all commercial building projects -- particularly through the increased efficiency of the existing primary heating systems. The effect of the projected 3.1 percent average annual growth rate in natural gas prices from 1988 to 2000 completely offsets the potential increase in commercial sector use of natural gas related to new construction.

Gas Markets Are Adjusting To Increasing Price Uncertainty

The long-term outlook for natural gas markets reflects a heightened competition among natural gas suppliers, as well as between natural gas suppliers and producers of alternative fuels. This increasingly competitive market structure is developing in response to (1) relative growth in the supply of gas not subject to price controls, (2) regulatory changes promoting the interstate movement of gas not directly owned by the transporting pipelines, and (3) the growing willingness of gas users to switch between energy suppliers. Hand in hand with the new competitiveness in natural gas markets is, of course, a growing uncertainty among market participants as to their future costs or revenues. Producers, transporters, local distributors, and consumers are all developing new marketing tools and strategies to cope with the increasing uncertainties and opportunities presented by a more flexible market.

Until recently, significant volumes of natural gas were sold under long-term contracts with inflexible pricing arrangements. Characteristic of today's market, however, is a greater reliance on spot sales, short-term supply agreements, and long-term supply agreements in which price terms are periodically renegotiated. Recently, intermediaries have

introduced brokered forward contracts, offering a way to link sellers wanting a longer-term supply commitment and buyers interested only in shorter-term purchases, and vice versa. The planned startup of a futures market in natural gas would offer yet another tool for traders to minimize price uncertainty or, alternatively, to take advantage of short-term price movements.

Rather than abandon long-term contracting altogether, producers and consumers alike appear to be working towards the establishment of an optimal portfolio of contract vehicles. The intent here is to strike a balance between the risks of adverse price movements (or the outright inability to secure outlets for, or supplies, of gas) and the profit opportunities presented by advantageous movements. Concern about security of supplies may be especially important for suppliers with non-interruptible customers. This balance is different for all companies and will change over time along with current perceptions as to the direction and stability of the market. In addition to a mix of long- and short-term contracts, and greater pricing flexibility generally, this dynamic portfolio may include direct producer-consumer contracts, contracts with pipelines, and, for consumers and pipelines, also the ownership of gas resources.

The changing market environment is also reflected in the way participants are conducting their businesses. For producers, the excess deliverability capability (or bubble) that has hung over the interstate portion of the industry since 1982 is finally being diminished, as suppliers become more free to contract with buyers at market prices. The gas bubble, which has depressed wellhead prices for a number of years, is forecast to dissipate by 1990. However, with a less certain long-term outlook for the market under deregulation and a greater potential for wide seasonal swings in gas prices, it is possible that some level of excess deliverability will become a permanent albeit seasonal phenomenon, shrinking with peak demand in winters and building again in summers.

For producers, access to transportation and the ability to contract directly with consumers will also result in more rapid signals from the marketplace. Thus, any expectation that prices may rise, for example, would translate into an incentive to increase productive capacity and vice versa. Any excess deliverability that develops in natural gas markets in the near future, however, will likely be the result of unanticipated gas demand and will be corrected through normal market signals, unlike excess deliverability seen in the early 1980's which had developed in large part because of regulatory and contractual impediments to downward movements in price for gas sold into the interstate market.

New Competitive Context To Influence Relationship of Gas, Oil Product Prices

The analysis of changes in gas markets relative to other fuels is complicated because gas competes with coal as well as oil in the important industrial and utility sectors. In the near term, coal-use decisions are dictated largely by the existing capital stock, with the result that competition between oil and gas is expected to dominate industrial and utility fuel choices through 1995. In the longer term, however, decisions about fuel substitution are influenced by relative capital costs as well as by fuel costs. As a result, competition between coal and gas is expected to become increasingly important after 1995 -- especially as electric utilities, faced by a need for additional generating capability, consider the economic advantages of natural gas-consuming combined-cycle plants. These plants are generally constructed on a much smaller scale (with lower capital cost) and require less time to bring into service (with lower cost and regulatory uncertainty) than competing coal-fired steam generating units. Smaller scale, nonutility generators of electricity, who will burn natural gas, are also expected to meet a growing share of the Nation's future electricity requirements.

As gas becomes more competitive, its price should track the energy-equivalent prices for alternative fuels more closely in end-use markets, although those alternative fuels will differ across consuming sectors and regions of the country (Figure 12). Nonresidential users of gas have demonstrated a new aggressiveness in negotiating price concessions and a greater willingness to switch to other energy suppliers when those concessions are not forthcoming. The ability of pipelines to offer lower prices to certain classes of consumers, the increased opportunity for producers and consumers to contract directly with one another, and the unbundling of services offered by interstate pipelines have enabled a more competitive market to develop. As a consequence, the average delivered price of gas has moved closer to the true incremental cost of production and transportation.

Even when comparing gas with directly competing fuels, precise pricing equivalence on the basis of Btu content should not be expected. In the residential sector, gas tends to be cheaper than heating oil on the basis of heat content, but in the industrial sector gas is generally more expensive than oil. Price differences for these competing fuels reflect relative convenience and some differences in supply risks, contracting practices (e.g., the interruptibility of gas

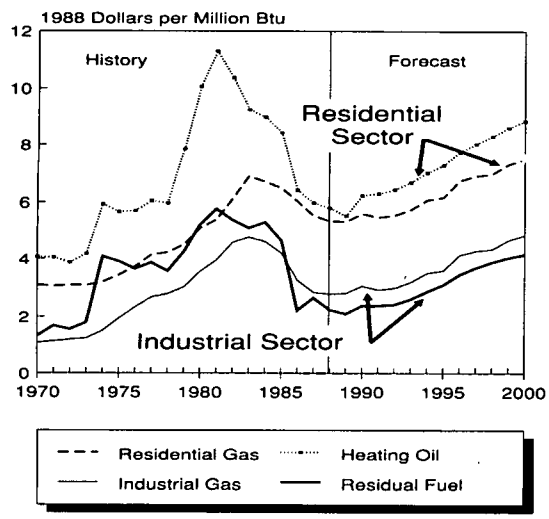
delivery), and capital requirements related to consumption, storage, and environmental standards.

Gas Prices To Go Up Across the Board, with Imports Doubling by 2000

Demand for natural gas should continue to grow after 1988, and production, imports, and prices for this fuel will keep pace as well.

The average national wellhead price for gas (in 1988 dollars) is projected to increase from $1.62 per thousand cubic feet in 1988 to over $3.90 by 2000 (Table A9). Comparable, although slightly smaller increases are expected for each of the major consuming sectors, as the unit cost of transporting and distributing gas is projected to decline somewhat. On the high end, the average price of gas to residential users is forecast to increase from $5.50 per thousand cubic feet in 1988 to $7.70 in 2000. At the low end, electric utility gas prices grow from $2.25 per thousand cubic feet in 1988 to about $4.30. The growing importance of the utility sector over the forecast period means the average price of gas to all sectors increases by less than $1.90 per thousand cubic feet, to about $5.70 -- an increase that is four-fifths of the forecast increase in average wellhead prices.

Gas Expected to Track Oil Product Prices More Closely



Source: See Appendix D.

Figure 12. Delivered Prices for Oil Products and Natural Gas, 1970-2000

Continuation of the trends of direct producer-consumer contracting and unbundling of transportation services may mean that prices will increasingly reflect only differences in the type of services that consumers require.

Over the long-term forecast horizon, growth in U.S. consumption of natural gas will exceed growth in domestic production by nearly 1 trillion cubic feet, based on the gas prices discussed here. It is assumed in this forecast that most of this difference will be made up from increased net gas imports. Net imports are projected to grow from 1.15 trillion cubic feet in 1988 to about 2.3 in 2000. Most of these additional supplies will come as pipeline gas from Canada, although 0.3 trillion feet annually is assumed to come in the form of liquefied natural gas (LNG) imports, mainly to meet winter peaking requirements. The outlook for Canadian imports is assumed not to be influenced by that country's ratification of the Free Trade Agreement, since the Canadian Federal and Provincial governments have already taken significant steps to remove restrictions on the production and export of gas.

Electricity Markets

The electric utility industry relies on long-term planning in meeting its commitment to provide reliable service to the public. However, electricity markets are currently experiencing changes that challenge the planning process. The rate of growth in electricity sales seems to be increasing, after a lull in the early 1980's that left some of the Nation's utilities burdened with excess generating capability. At the same time, recent weather extremes have strained peak load capabilities in parts of the country for the past two summers. Will this growth continue and the summer extremes abate, so that capacity planning can again take place on a relatively certain basis? Will current excess capacity be fully utilized before planned or in-progress construction is completed? If the industry is partially or wholly deregulated, as is being discussed, how will utilities choose among the expanding options of future sources of supply in a way that maintains the regulatory requirement of providing reliable service?

Planning for New Generating Capability Faces Uncertain Demand Growth

The major part of the utility construction program of the 1970's is now in place and included in the rate base. Demand has picked up recently due to the weather and robust economic growth (and a consequent growth in housing, office construction,

manufacturing activity, and a continued consumer preference for electric appliances). As a result, the requirement for further new construction is expected to grow, despite the current excess capacity.

However, some utilities have not been able to recover the costs of constructing new generating units that have been completed or are in various stages of completion (or even abandoned for economic reasons). Uncompleted nuclear generating plants are the most notable example. State public utility commissions may not allow all these costs to be recovered through increases in the current rate base. Those utilities with currently unrecoverable costs related to plant construction provide clear evidence of the dangers of relying on overly optimistic expectations of electricity growth in planning large investments in an uncertain regulatory environment.

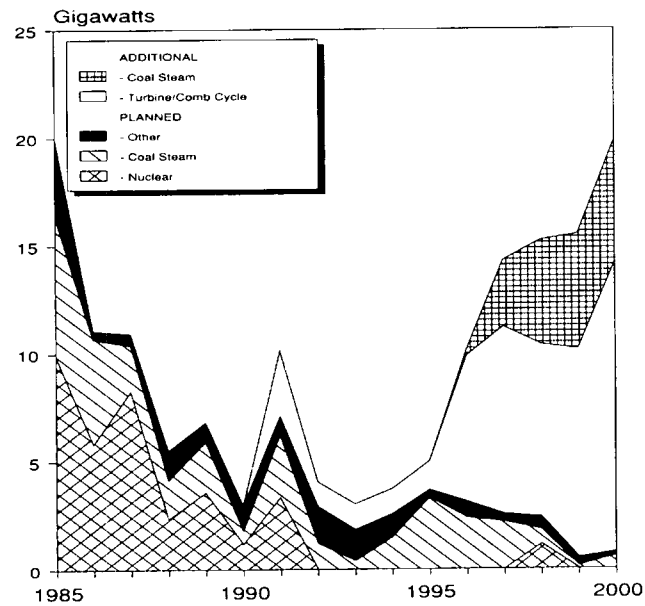
High Capital Costs and Long Lead Times Favor Smaller-Scale Supply Projects

Many utilities are planning for conservative levels of demand growth and are being prudent in their choice of generating capacity investments. In the past 10 to 15 years, a typical utility investment for baseload power was for a large (500-1000 megawatt) coal-fired generating unit. Currently, a plant of this size would cost over $1 billion and take 8 to 12 years to complete. Given the potential financial risks of adding large new plants for generating electricity, the industry as a whole is now more likely to manage electricity supplies in the future via smaller incremental investments in supply capability (Figure 13) or via incentives for demand reductions.

Supply options will include, in addition to construction of more of the mainstay coal-fired steam units:

- Investment in turbines and newer, more efficient technologies such as combined-cycle units, which are both smaller and less capital intensive than the traditional coal-fired plants
- Efforts to extend the operating lifetimes of existing capacity through planned life-extension programs (in some instances, investments to delay plant retirements may be more cost effective than building new capacity)
- Increased reliance on electricity supplied by nonutility generators, as facilitated by the Public Utility Regulatory Policies Act (PURPA)
- Increased electricity imports from Canada.

Investment in New Generating Capacity Seems Necessary by Mid-1990's



Source: See Appendix D.

Figure 13. Additions to Electric Utility Generating Capability, 1985-2000

Continued emphasis on conservation and demand management, both by utilities and as a consequence of public policy, may reduce the need for new generating capability. Alternative pricing schemes that encourage more conservation during peak demand periods is just one of the options in this area that utilities may pursue. Continued improvements in the energy efficiency of appliances and buildings will also be important.

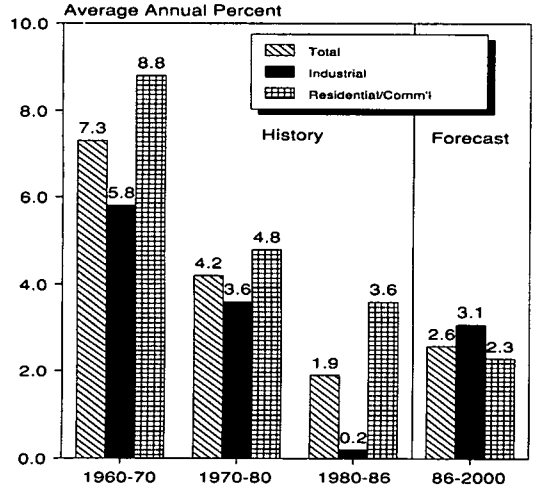
Low Demand Growth of the 1980's Should Speed Up During the 1990's

During the 1960's, sales of electricity grew on average at about 7.4 percent per year. In the 1970's, this growth slowed to 4.5 percent per year, and between 1980 and 1986 fell even further, to an annual rate of 1.9 percent. The electricity growth of the 1960's was based largely on the increased use of appliances (particularly, air conditioners) in the residential and commercial sectors, where growth was higher than the national average (Figure 14). In the 1970's, growth in the residential and commercial sectors was still above the average, but it was slowing. The large drop in total electricity demand growth between 1980 and 1986 was due

primarily to a decline in sales to the industrial sector. Industrial consumption slowed during this period because of conservation and the relatively poor performance of certain large, energy-intensive industries.

Since 1986, electricity demand growth appears to have picked up again. This is due to a combination of forces. In addition to two successive summers of record heat, electricity demand has been increasingly responsive to the economy and the weather. The large electricity-intensive industries (chemicals, primary metals, metal fabrication, and paper) have enjoyed an export boom that is projected to continue, albeit more moderately, throughout the forecast period. There is also evidence that demand for electricity in the residential and commercial sectors has been particularly sensitive to temperature changes in the past several years, which suggests that the use of electric air conditioning and heating is increasingly prevalent -- both signs of a prosperous economy and consumer investment.

Recent High Growth Rate for Sales of Electricity Reverses Trend



Source: See Appendix D.

Figure 14. Growth Rates for Electricity Sales by Sector, 1960-2000

As a result of the high electricity demand of the last 2 years, this year's forecast has been raised slightly. Between 1988 and 2000, electricity sales are projected to increase by about 2.6 percent per year, driven by a growth rate of 3.2 percent per year in the industrial sector and 2.7 percent in the commercial sector.

Residential sector demand growth should be slower (averaging only about 1.8 percent per year) as additions of air conditioners and other electricity-intensive products slacken because of market saturation and increasing equipment efficiency. However, the increasing use of electric appliances in existing housing units means that electricity growth is still greater than the growth in total housing units.

Commercial sector growth is likely to be slower in relation to its recent growth rate through 1988, averaging 2.7 percent per year. This is primarily due to a slowdown in commercial construction, as new construction comes more into balance with the demand for commercial floor space. Commercial buildings that were constructed over the last 10 years are more electricity intensive than buildings constructed earlier (EIA, *Commercial Buildings Consumption and Expenditures 1983*, Table 15). The current rapid growth is attributed to the large expansion in commercial activity.

Industrial sector demand for purchased electricity is projected to grow, as large electricity-intensive industries such as primary metals, chemicals, and metal fabrication increase their output in response to economic growth both domestically and abroad. The rate of increase in electricity use per unit of output in the manufacturing sector had slowed down from 1973 to 1983. However, the rate of increase in electricity per unit of output in the forecast period is similar to the higher rate observed since 1983 (which in turn follows the historic rate of increase in the decade before 1973).

The historical trend of growing electricity use in all sectors continues throughout the forecast period, although at a somewhat slower rate. The major consuming sectors may be approaching saturation (in the context of current income levels and currently available electric products). Also, the average efficiency of electric appliances and of heating and cooling with electricity is projected to increase. However, real electricity prices remain relatively flat throughout the forecast, making electricity increasingly cheaper relative to other fuels, which tends to increase demand.

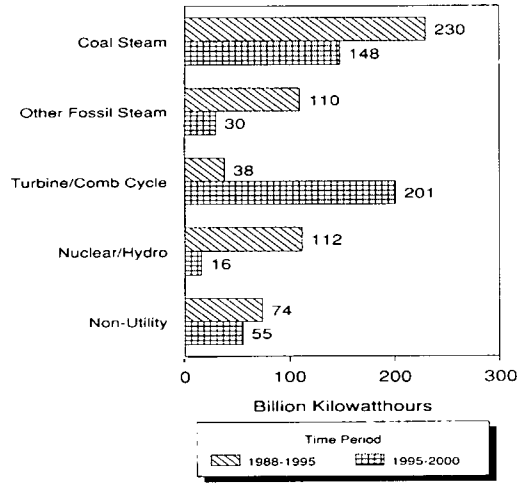
Combined-Cycle Units, Nonutility Output Highlight Electricity Generation Forecast

With demand for electricity growing throughout the forecast period and most currently announced plans for new generating capability coming on line by the mid-1990's, additional needed capacity will rise

sharply through the remainder of the century (Figure 13). It is projected that the combined-cycle and coal steam capability additions beyond currently announced plans will need to begin operation by 1996.

Electricity produced by combined-cycle generating units should begin to make a significant contribution to the Nation's power supply, especially after 1995 (Figure 15). The 1987 amendment to the Powerplant and Industrial Fuel Use Act of 1978, eased restrictions on gas use, removing an important legal impediment to the construction of new gas-fired generating capability. Combined-cycle units, which can be built in smaller capacity increments than traditional large-scale baseload facilities, will burn natural gas. If natural gas prices rise to the point that coal gasification becomes an economically viable technology, these plants can be converted to take advantage of it by adding coal gasifiers. However, this is not expected to occur before 2000. By the year 2000, the total capability of combined-cycle units at utilities should be about 45 gigawatts, compared with only 7 gigawatts in 1995.

Smaller-Scale Technologies Dominate New Generation After 1995



Source: See Appendix D.

Figure 15. Changes in Utility and Nonutility Generation by Plant Type, 1988-2000

Coal and nuclear generating capability, which together in 1988 accounted for 57 percent of all generating capability and about 76 percent of total generation, should grow at a much slower rate over the forecast horizon than in recent years (Table A5). Utilities have announced intentions to add only about 18 gigawatts (net, after accounting for retirements) of coal-fired baseload capacity over the next 12 years, as increased construction and site acquisition costs lead utilities to shy away from the large baseload plants constructed in the past, in favor of smaller facilities such as combined-cycle units (Table A6). Similarly, net additional nuclear capacity is expected to total only about 9 gigawatts through 2000. This estimate includes only nuclear generating units that are currently under construction. The current status of each of these units has been evaluated, and completion dates have been estimated on the basis of recent progress in construction and licensing. In addition, utilities are expected to increase their utilization of both coal and nuclear plants by some 10 percentage points from 1988 rates to meet the increase in demand.

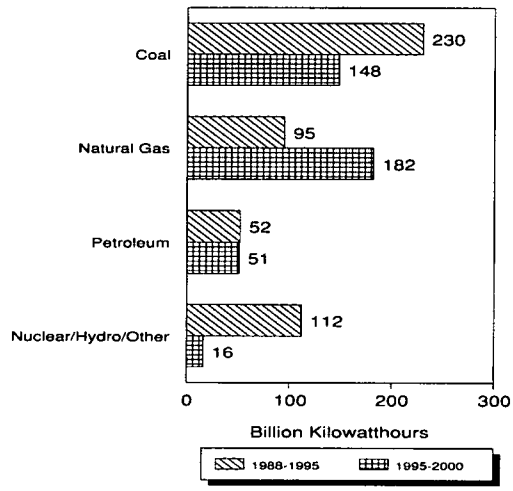
Turbine facilities are expected to grow from 45 gigawatts in 1988 to over 63 gigawatts of generating capacity by 2000, mainly as a result of increased peaking requirements. These units burn natural gas and distillate to meet peak demand more economically than the more capital-intensive baseload units.

Finally, this forecast incorporates an increase in nonutility generation by the year 2000 of about 129 billion kilowatthours. Nonutility generators, which include qualifying facilities and other customer-owned and industrial generation, are projected to make up about 7 percent of total generation by the year 2000.

Utility Fuel Mix Still Favors Coal, But Oil and Gas Use Can Rise Sharply

Changes in primary energy sources of electricity supply over the forecast period are shown in Figure 16. The major increment in supplies will continue to be fossil fuel generation. There will be a particularly significant increase in gas-fired generation (from steam, turbine, and combined-cycle plants) by 2000, from 272 billion kilowatthours in 1988 to nearly 550 billion kilowatthours by the year 2000. Similarly over the same period, while total generating capacity increases by less than 12 percent, total electricity generation increases by about 33 percent. These trends reflect significant improvements in utilization for all types of capability.

Electric Utilities Turn Increasingly To Natural Gas



Source: See Appendix D.

Figure 16. Changes in Utility Generation of Electricity by Fuel, 1988-2000

Although only a small portion of total generation, oil-fired generation nearly doubles over the forecast period. Except for turbines using diesel, however, virtually no additions are planned for oil-burning facilities for the rest of the century. The consumption of oil is projected to increase, as much of the excess capacity of the Nation is oil fired. Peak demand and favorable oil prices led to the very high utility oil consumption experienced in 1988. Given the relatively low oil prices projected here (compared with last year's forecast), this capacity is expected to be used in meeting the expanding demand and, by the year 2000, should be more fully utilized. Oil-fired plants (which include dual-fired oil and gas facilities) consumed about 0.6 million barrels per day of fuel oil in 1988 (Table A4), and are forecast to use 1.1 million barrels of oil per day in 2000.

Higher Fuel Costs, Lower Capital Charges Stabilize Real Electricity Prices

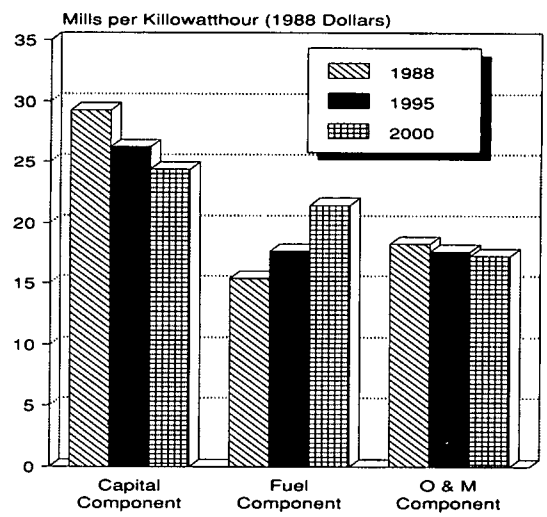
Despite substantial increases in the prices of natural gas and residual fuel oil, together with somewhat smaller increases in the price of coal, real electricity prices at 6.5 cents per kilowatthour in 2000 (1988 dollars) are expected to be little changed from their 1988 level.

Without entering into the complexity of utility ratemaking, the price of electricity is set fairly simply, in accounting terms, by taking the dollar revenue requirement for fuel, capital, and operation and maintenance for a particular utility and dividing it by the utility's total level of sales in kilowatthours. The capital component includes depreciation, taxes, and a return on investment. The result, expressed in cents per kilowatthour, is the average cost of electricity.

In 1988, a considerable amount of excess capacity existed, cutting into the immediate need for future construction. Net additions to the rate base from construction are accordingly small, and accounting depreciation steadily reduces the total capital component of the rate base throughout the forecast. As a result of only slowly rising fuel costs and the steady decrease in the capital component, falling electricity prices are expected through the mid-1990's (Figure 17).

After 1995, new construction will be required, and growth in the rate base from these additions will start to offset the price dampening effects of depreciation. Assumed increases in world oil prices also cause fossil fuel costs to utilities to increase by almost 4 percent per year after 1995, leading to growth in average electricity prices of 0.5 percent per year from 1995 to 2000.

Increasing Fuel Prices Offset Benefit of Declining Capital Costs



Source: See Appendix D.

Figure 17. Components of Average Electricity Price, 1985-2000

Regulatory Reform Could Change Structure of Electricity Industry

Not considered in this forecast is the possible role of deregulation in setting the price of electricity as a competitive commodity in the marketplace. Electric utilities are increasingly purchasing electricity supplies on the open market. Differences between the costs of purchased and utility-generated supplies, however, are presenting challenges to the traditional pricing structure of the industry.

One proposal currently being studied by the Federal Energy Regulatory Commission (FERC) and other organizations would assist the process of long-term capacity planning by increasing competition within the utility industry. Regulatory reform of the electricity industry, a subject of great interest in the past year, has been likened to a "three-legged stool." Development of a competitive market through three notices of proposed rulemakings (NOPR's) is one leg; reform of the Public Utility Holding Company Act (PUHCA) is the second; and the resolution of transmission issues is the third.

FERC's Proposals Intended To Foster Competitive Supply

The intent of FERC's three NOPR's is to increase competition in supplying electricity, to promote economic efficiency in implementing the Public Utility Regulatory Policy Act (PURPA), and to develop new generating capacity. The first FERC proposal would allow relaxed regulation of independent power producers. The second proposal allows States to use bidding as an alternative to administratively determined avoided cost (the basis on which utilities must pay nonutility suppliers). The third focuses on clarifying existing PURPA regulations and determining appropriate measures of "avoided cost."

The FERC rulemakings would allow States to establish a competitive system that allows utilities to select the best facilities to accommodate their needs. Many criteria, including reliability, local fuel consumption, and environmental impacts, would be used by utilities. However, low price would probably be the most important. Utilities and any other independent power suppliers would be allowed to compete against qualifying facilities as defined by the PURPA. PURPA has created a market for power generated by qualifying facilities, by requiring utilities to purchase this electricity at their own avoided cost. A qualifying cogenerator is a facility less than 50 percent-owned by a utility which meets fuel efficiency standards established by the FERC. A qualifying small power producer is a nonutility facility with a capacity not exceeding 80 megawatts, which limits its level of consumption of fossil fuels to no more than 25 percent of total input fuels. This generally means electricity from hydroelectric, wind, waste, or biomass generation.

Independent power production has the potential to be an important source of power, because utilities are undertaking few major new construction projects. For example, the projection of nonutility generation for sale to utilities in this *Outlook* more than doubles by the end of the century, from about 57 billion kilowatthours in 1988 to some 118 billion kilowatthours by 2000. More than 40 percent of the forecast growth in nonutility generation is accounted for by gas-fired facilities.

Although nonutility generation is attractive to many utilities seeking to avoid building new generating capability, several issues must be addressed before this idea can become reality: pricing of nonutility supplies, regulatory constraints on the ownership of independent power producers, transmission system access, and the maintenance of electric-system reliability. Because utility supply and systems were not designed with nonutility generation in mind, utility groups maintain that these fringe suppliers must be controllable within the current operating network. Utilities contend that nonutility supplies should be scheduled and be capable of being dispatched to match utility load characteristics.

Current Debate on the NOPR's Should Lead to Decisions in 1989

FERC is currently reviewing final comments on the NOPR's and should finalize or modify the rules in 1989. The focus of the proposed FERC rules is efficiency. Some utilities claim that they have been forced to buy more cogenerated power than they need at a price that is too high, exacerbating the utilities' own excess capacity problem. A competitive bidding system could help to alleviate some of these problems by allowing utilities to determine how much nonutility supply is appropriate. Opening the bidding process to nonqualifying facilities should also increase supplies and the level of competition. On the other hand, industry advocates hasten to add that the current system of localized monopolies in electricity generation has provided a reliable source of power for decades. Analysts have noted that there is a risk that the creation of new sources of electricity supply by revising longstanding relationships between producers and consumers could have unforeseen consequences.

Public Utility Holding Company Act Is a Further Complicating Factor

Even if the NOPR's survive without major modifications, the independent power producers cannot develop without some change in the Public Utility Holding Company Act (PUHCA). Under PUHCA, a utility is defined as a company owning 10 percent or more of a power generation, transmission or distribution facility, and is subject to Securities and Exchange Commission rules if the company has a parent/subsidiary corporate arrangement.

Taken to the extreme, the PUHCA regulation could mean that an industrial firm would have to divest itself of all nonutility business if it wants to build an independent power producer facility. If PUHCA were not amended, utility-owned qualifying facilities are more likely to develop than independent power producers. Allowing utilities to own qualifying facilities would do little to benefit nonutilities. Utilities worry that FERC would prohibit them from buying power from their own qualifying facilities. One approach is to amend PUHCA to exempt from the act independent power producers, defined as generators of power sold exclusively in the wholesale markets. There are other alternative approaches, and all will have to be examined.

Issues of Access to Transmission Remain a Topic for the Future

FERC does not address access to a utility's transmission lines in its NOPR's. Enhanced competition in some electricity markets could involve increased transmission, or "wheeling," of electricity across utility service areas. This wheeling enables utilities and their customers to buy power directly from alternative sources. There are two types of transmission access in electricity markets: supplier (or wholesale) access and customer (or retail) access. The electric utility industry, in general, is opposed to mandatory retail wheeling, fearing a loss of their major customers, while proponents of open retail access argue that open transmission lines are necessary to ensure a competitive market. Theoretically, open access would promote more competition between suppliers and overall efficiency, as electricity consumers shop around for the lowest price or most reliable source of supply.

Certain Events and Issues Affect Nuclear Power's Outlook

The average utilization rate of domestic nuclear power plants was on the increase during 1988. The higher utilization rates appear to be due to increased electricity demand related to extreme weather and to the electric utilities' emphasis on improved nuclear power plant performance (through increased operator training and less frequent refueling outages).

In the first 9 months of 1988 the utilization rate was 64.5 percent as compared to 57.7 percent for the same period in 1987 (Tables A4 and A5). The largest monthly increase occurred in July, when the capacity factor was 70.5 percent. In addition, four of the eight nuclear units that became operable in 1987 had capacity factors greater than 85 percent in July 1988. This was considerably higher than the average capacity factor for the first operating fuel cycle of new units, which is typically less than 60 percent. Forty-five of the 108 operable nuclear units had capacity factors greater than 90 percent for the month.

Legislation important to the future of the nuclear-power industry was proposed, debated, and in some instances passed during the year. The Price-Anderson Act was reauthorized and extended for 15 years. This act requires that nuclear utilities carry insurance to cover damages, provides a mechanism for the payment of damages, and limits total liability to about $7 billion. Further, in case of an "extraordinary nuclear occurrence," the utility is still held liable regardless of fault.

Legislation streamlining the Nuclear Regulatory Commission (NRC) nuclear power plant licensing process was also introduced in the U.S. Congress in 1988. The goal in this area is to establish a so-called one-step licensing provision. This provision would allow the NRC to issue a combined Construction Permit/Operating License if the unit were built to a pre-approved, NRC-certified design. This aspect of licensing reform is an essential step toward design standardization.

The low-power testing and issuance of Full Power Operating Licenses for two completed units, Shoreham and Seabrook 1, have continued to be delayed. Debate over NRC approval for low-power operation of Seabrook 1 is proceeding. Earlier in the year, however, it appeared that Shoreham would be canceled altogether. As a prelude to abandonment, a tentative agreement between Long Island Lighting Company and New York State was designed to transfer ownership of the Shoreham unit from the utility to the State. This tentative agreement, however, failed to win the State Legislature's approval. In November, President Reagan gave the Federal Emergency Management Agency the authority through an Executive Order to draft evacuation plans for nuclear power plants

whenever State or local governments decline to participate. Subsequently, the staff of the NRC recommended that consideration of a Full Power Operating License for Shoreham proceed without New York State or Suffolk County participation in emergency planning. New proposals by New York government offices and NRC deliberations are still ongoing.

Another issue that could affect the nuclear projections is the possible reactivation of deferred or canceled nuclear construction projects. Thirty-six units, more than 1 percent complete, have been deferred or canceled. Thirty-one of the 36 units have been irrevocably canceled and 5 (Grand Gulf 2, Perry 2, Seabrook 2, Washington Nuclear Project (WNP) 1 and 3) have been deferred. A decision to reactivate these units would depend on the need for baseload power, the cost of completing the units as compared to the cost of constructing a new plant, and the financial stability of the owners and financial risk associated with recovering the investment cost. Grand Gulf 2, Perry 2, and WNP 1 and 3 are candidates for reactivation in the 1990's and could be operable in 4½ to 7 years after such a decision, adding a total of 4.9 gigawatts of electricity generating capability to the forecast presented in this *Outlook*.

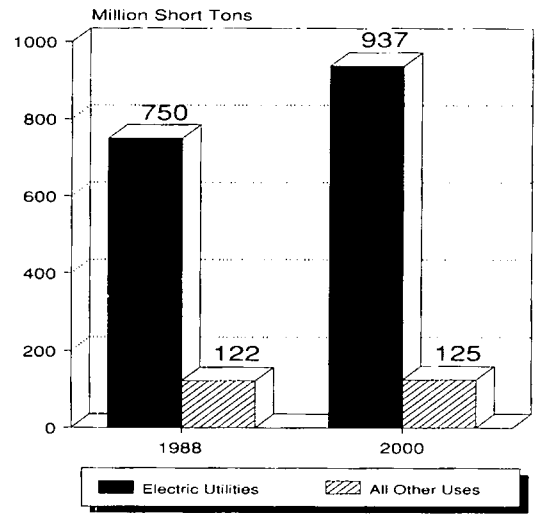
Coal Markets

Coal is expected to continue as a mainstay of domestic energy supply through the year 2000. In fact, coal is expected to account for 25 percent of the total energy consumed nationally, up slightly from its 1988 share of 23.7 percent. This increase in coal use is due in large part to the ever widening gap between the price of coal and the prices of oil and gas.

Electric utilities in 2000 are expected to continue to be the biggest market for coal, with 80 percent of domestic production being consumed by the utilities, the same percentage as in 1988. Relative coal use drops to just over 50 percent of fuels consumed at utilities in 2000, down from its 1988 level of 55 percent. Focusing just on the coal market, however, utilities actually account for most of the growth in coal use, increasing their demand from 750 million short tons in 1988 to 937 million short tons in 2000 (Figure 18).

The use of steam coal in industrial activities is expected to lag slightly behind the growth in total energy consumption in the industrial sector, while the use of coking coal continues its steady decline due to technological advances in steel production and the consequent loss of domestic markets.

Electric Utilities Dominate Growth in Projected Consumption of Coal



Source: See Appendix D.

Figure 18. Domestic Use of Coal, 1988-2000

Minemouth prices are expected to rise from $23.61 per short ton in 1988, to nearly $26 per short ton in 2000, a 0.8 percent increase per year (1988 dollars). This is due in part to the low world oil prices and moderate economic growth projected in this *Outlook*. Another major factor in the dampening of price growth is an excess in coal production capacity, which is expected to continue through the early 1990's. End-use prices are also expected to remain soft throughout the forecast period due mainly to modest increases in transportation costs. The average price to all end users rises from the 1988 level of $32.28 per short ton to just under $36 per short ton in 2000.

Even though the world coal market is expected to expand during the forecast period, the U.S. coal exporters' relative share of this expanding market will shrink. New players in the world coal market, such as China and Colombia, are expected to gain a bigger share of the growing Asian and European markets (and in some cases, even penetrate domestic markets).

The Drought Had a Mixed Effect on Coal Consumption in 1988

The year 1988 was a mixed one for many in the coal industry. Through May, exports and production were indicating a prosperous year for coal, but by mid-June the consequences of the

drought began to be felt throughout the country. As the waterways began to dry, hydroelectric generation declined, and in some cases nuclear and even gas- and coal-fired generators were threatened with closure for want of cooling water. With the heat wave baking the Nation, demand for electricity surged. When shipping by water became problematic, coal transporters found themselves competing with other products, such as grain, for increasingly scarce and more expensive rail space.

Coal movements on the Mississippi were greatly restricted -- both north to the consuming utilities, who were experiencing record-setting demand for electricity and south to marine terminals to accommodate an increase in the demand for coal exports. In most cases utility inventories proved to be adequate. Although the Coast Guard lifted restrictions placed on barge movements in early September, the threat of reimposing restrictions kept barge movements below normal for weeks after. Even before the problems on the Mississippi started, barge rates were increasing and the drought only helped to push them up. Some transporters took heavy losses when they were forced to pay higher rates or seek more expensive modes of transportation to meet contractual obligations, while some producers benefitted from the increase in the demand for electricity.

Some Form of Legislation on Acid Rain Appears Likely

Although experts are split on the future effects of any proposed deregulation of electric utilities on coal, most do agree that current legislation to reduce emissions from coal plants will almost certainly have an adverse impact on producers of high-sulfur coal. With a growing perception by the general public that acid rain and the greenhouse effect are important issues that must be addressed, future legislation requiring reductions in emissions from the burning of coal may be forthcoming.

Already, the Environmental Protection Agency has finalized the "Revised New Source Performance (RNSP) Standards" designed to reduce emissions from industrial boilers. This will certainly add to the difficulties for coal as a viable fuel for many in the industrial sector and require either the installation of scrubbers or the use of more advanced emission controlling boilers, such as fluidized-bed combustion units. To meet the new standards for emissions being proposed for electric utilities, reliance on current technologies would place a premium on current low-sulfur compliance coals. The capital costs for all new generating plants complying with these new standards would also be higher. In the forecast, it is assumed that all new coal-fired steam units meet government standards with additional scrubbing and coal is priced on the basis of the minimum necessary quality premium.

Emission Control Technologies Are Focus of Research and Development

The Department of Energy, through the "Clean Coal Technology Program," has awarded over $1 billion for research into the development of technologies to reduce emissions. The lion's share of these awards is directed toward demonstration projects for the retrofitting or repowering of older North Central-based plants, which are pointed to as the leading contributors to acid rain in the Northeast and Canada. This in turn supports the ongoing cooperation between Canada and the United States to address the acid rain problem.

One of the more promising "clean coal" technologies is fluidized-bed combustion. This process consists of burning a coal and absorbent (such as limestone or dolomite) mixture in a "fluidized" state by forcing air through the powdered mixture. As much as 90 percent of the sulfur dioxide can be removed from the emissions this way. This method allows the burning of a wider variety of coals, offers higher combustion efficiency, and lower costs in preprocessing of the coal (i.e., crushing as opposed to the more costly pulverizing). In addition to sulfur dioxide emissions, nitrogen oxides are also reduced due to the relatively lower combustion temperatures.

Some success stories connected with this technology are the Colorado Ute Electric Association, with over 100 megawatts of capacity, and the soon to be resurrected (estimated completion in 1990) Tidd Power Plant in Brilliant, Ohio, which was closed in 1976 due to the economics involved in emission controls. One of the more innovative byproducts of fluidized-bed combustion is its use in cleaning the environment. The Department of Energy is sponsoring a study at the Good Samaritan Hospital in Lebanon, Pennsylvania, to evaluate the feasibility of burning medical wastes along with coal in a fluidized-bed heat plant. This would give hospitals a cost-effective on-site waste disposal system, in addition to the energy it produces for cogeneration applications.

Preliminary results from a cooperative research project on underground coal gasification between the Department of Energy and the Gas Research Institute has proved to be a technologically and economically feasible method to produce substitute natural gas. The methods under study involve igniting the coal seam and injecting an oxidant into

one well and producing the gas substitute from a connecting second well. These methods allow unminable coal to be converted to low- to medium-Btu gas with little or no above ground residues. Conservative estimates suggest that there is considerable potential in existing unrecoverable coal reserves.

Coal Exports Are Expected to Rise Slowly

Over the forecast, total exports for steam and metallurgical coal rise from an estimated 86 million short tons in 1988 to 112 million short tons by the year 2000 (Table A10).

Over the past few years the market for metallurgical coal has declined along with the demand for steel. At the beginning of 1988 the price of metallurgical coal was somewhat soft and the demand expectations of American exporters low. Therefore, it was not surprising that some exporters were caught off guard by an unexpected rise in the demand for steel, and sold coal to some Japanese importers at what now might be viewed as bargain prices. This increase in the demand for steel, along with the Australian coal strike and the lower dollar abroad, led to the reversal of the expected decline in exports for 1988.

In summary, 1988 was a year of good and bad news for the coal industry, perhaps contributing to, or at least characterizing, the course of the industry for the rest of the century. While coal remains the most abundant and least expensive domestic energy resource, its continued expansion as a major player in the energy market will depend on how the coal industry addresses the environmental issues and transportation costs necessary for expansion. Foremost on the industry's agenda will be the development of technologies necessary to control the emissions connected with the use of coal, with additional legislation directed at emissions standards possibly forthcoming. In addition, research into alternative methods to extract energy from coal, such as underground gasification and coal liquefaction, should continue.

How This Outlook Compares With Others

- Assumptions
- Demand Projections
- Supply Projections
- Price Projections

Alternative Views

The projections presented in the *Annual Energy Outlook 1989* (*AEO 1989*) reflect EIA's present understanding of world and domestic energy markets and changes that are likely to evolve in the future. This chapter compares the base case forecast with the forecast presented by EIA last year and with two other recently published forecasts, by Data Resources, Inc. (DRI) and Wharton Econometric Forecasting Associates (WEFA).

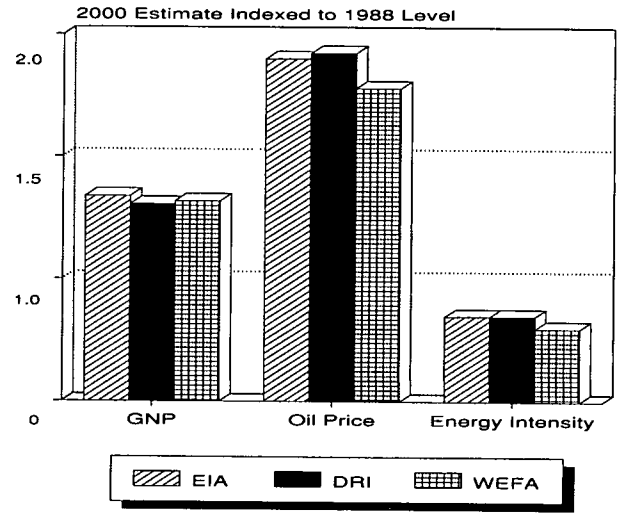
Many other forecasts have been prepared by numerous organizations, including the American Gas Association, the Gas Research Institute, Arthur Anderson and Associates, major oil companies, and specific study groups such as the recently published Washington Policy & Analysis study of natural gas. It is not possible to compare all these forecasts. DRI and WEFA are among the principal commercially available forecasts with readily available documentation that facilitates comparison of underlying assumptions as well as results.

This comparison focuses on the similarities and differences among the alternative forecasts for the year 2000, starting with the key assumptions of economic growth, world oil prices, and energy efficiency. Differences between EIA's base case energy projections and the others are addressed in the aggregate as well as on a sector-by-sector basis.

Economic and Price Assumptions

In general the most significant difference between the three energy supply and demand forecasts can be attributed to differing expectations for domestic economic activity, world oil prices and energy efficiency (Figure). The DRI and WEFA energy forecasts are based upon their current macroeconomic forecasts. There is some disagreement about the overall performance of the economy, with average annual growth projections ranging from 2.3 to 2.5 percent through the year 2000. With the highest assumed growth rate, EIA assumes the highest GNP estimate for the year 2000 at $5,368 billion (1982 dollars). While the assumptions for overall economic growth are similar for all three forecasts, the details of this expected growth differ significantly. The WEFA forecast projects a balanced growth across all sectors, both manufacturing and service, while the DRI forecast projects more growth in manufacturing than in the service sectors. EIA's forecast is midway between the two. The higher GNP forecast chosen by EIA reflects a judgement that recent DRI and WEFA projections have understated short-run GNP growth potential and, while backing the DRI view of manufacturing, places additional growth in the service sectors of the economy.

Three Forecasts Display Little Difference in Major Assumptions



Source: See Appendix D.

Figure 19. Change in Assumed Growth, Oil Price, and Energy Intensity, 1988-2000

From an energy price perspective, the *AEO 1989* and DRI projections of the world oil price in the year 2000 are very similar, at $28.00 and $28.32 per barrel (1988 dollars), respectively. However, the two forecasts differ in their estimation of the growth path that oil prices will take to reach the $28 level in the year 2000. While the *AEO 1989* assumes that prices will maintain relatively constant growth over the forecast period, DRI projects rapid increases through 1992 and more modest growth for the remainder of the decade. WEFA projects a lower price, reaching $26.30 in the year 2000. On its own, the lower oil price assumption would serve to increase aggregate energy demand, however, this effect is more than outweighed by the WEFA conclusion of a more energy efficient economy.

Given the GNP and oil price outlooks, the next determinant of energy demand projections is the energy intensity of the economy. Although this is a conclusion not an input assumption, it represents a convenient point of comparison between the three forecasts. The level of energy intensity assumed by the EIA, DRI, and WEFA forecasts is dependent in part on the specific mix of economic activity. While

all three of the forecasts expect an expansion for the industrial sector in the aggregate, the differences in the assumed composition of this growth are responsible for the differences in energy intensity. The *AEO 1989* and DRI forecasts expect higher growth than WEFA for the manufacturing sector, especially the chemical and primary metal industries. Since these industries are among the most energy intensive, this leads to a higher level of industrial sector energy demand relative to the WEFA forecast and a higher projected level of energy intensity for the EIA and DRI forecasts.

The decline in the ratio of energy consumption to GNP across the three forecasts can also be attributed to a shared expectation of efficiency improvements, as energy-consuming equipment is retrofitted and replaced over time. Both the *AEO 1989* and DRI project a decline from the 1988 ratio of 19.8 thousand Btu per 1982 dollar of GNP to 16.9 thousand Btu per dollar by 2000. On the other hand, the WEFA ratio of 16.0 thousand Btu per dollar is considerably lower than the other two forecasts. The variation between these ratios reflects the changes in the composition of economic activity assumed by each forecast. The relatively low demand for primary energy projected by WEFA can be attributed to strong growth projections for the services sector of the economy, with much slower growth anticipated for industrial output, particularly in many of the energy-intensive sectors.

On balance, the more energy-intensive economic assumptions used by the EIA and DRI forecasts yield consumption estimates which are higher than provided by WEFA. Projections for some of the principal economic determinants of U.S. energy demand are presented in Table 3, along with estimates of the world oil price.

Demand Projections

A Narrow Range of Demand Forecasts

Projections of total energy demand in 2000 vary little across the three forecasts considered, although there are significant differences for particular fuels. Figure 20 shows a comparison of the *AEO 1989*, DRI, and WEFA consumption projections indexed to the 1988 levels. As seen in Figure 20 the *AEO 1989* has the highest projection for total energy consumption; DRI, the second highest; and WEFA, the lowest. This result is not surprising and is a consequence of the economic assumptions discussed.

Looking at the consumption projections for specific fuels, the *AEO 1989* forecast is set apart by its projections for natural gas and electricity consumption. The *AEO 1989* has the highest projection of electricity consumption by all sectors and has the only projection for actual growth in natural gas consumption over the 1988 level. These

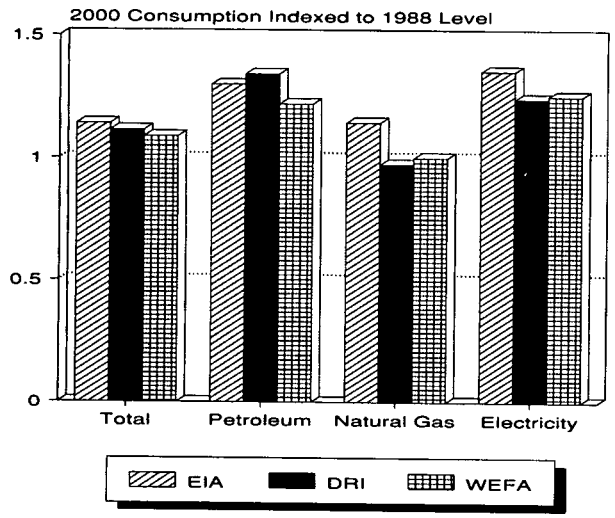
Table 3. Comparison of Principal Determinants of U.S. Energy Demand in 2000

Determinant	EIA Last Year	EIA *AEO 1989*	DRI	WEFA
Real GNP (billion 1982 dollars)	5,090	5,366	5,236	5,286
Real GNP Growth, 1988-2000 (average annual percent)	2.3	2.5	2.3	2.5
New High-Grade Bond Rate (percent)	9.7	9.8	9.6	9.9
Industrial Production (index, 1988 = 1.0)	1.34	1.41	1.40	1.43
World Oil Price (1988 dollars per barrel)	31.67	28.00	28.32	26.30

Sources: ***Last Year***: Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988). **DRI**: Data Resources, Inc., *Energy Review* (Lexington, MA, Autumn 1988). **WEFA**: Wharton Econometric Forecasting Associates, *Energy Analysis Quarterly* (Bala Cynwyd, PA, Summer 1988).

two results go hand in hand since much of the additional electricity generation is expected to be fueled by natural gas. On the other hand, DRI projects the largest growth for petroleum consumption. For the most part, the higher DRI estimate can be attributed to a higher expected transportation consumption.

EIA Is Higher in Projection of Use for Both Electricity and Gas



Source: See Appendix D.

Figure 20. Change in Consumption of Major Fuels, 1988-2000

The contrast in projected fuel consumption is apparent when comparing the sectoral demand projections of the three forecasts.

For the residential and commercial sectors together, the DRI demand projection of 16.5 quadrillion Btu is significantly lower than the other two forecasts (Table 4). The *AEO 1989* and WEFA both projected total consumption by these sectors at approximately 17.2-17.3 quadrillion Btu. The *AEO 1989* forecast attributes the bulk of the residential and commercial growth to electricity consumption, whereas WEFA projects a greater share of consumption for natural gas. For the industrial sector, the *AEO 1989* projects demand to rise to 24 quadrillion Btu in 2000, up from 22 quadrillion Btu in 1988. In contrast DRI sees a more moderate growth in industrial energy demand and WEFA expects the demand to stay near the 1988 level of 22 quadrillion Btu. Once again the three forecasts are set apart by differing expectations for electricity and natural gas consumption. The *AEO 1989* estimates industrial natural gas consumption over 1 quadrillion Btu above that of the other forecasts, and electricity consumption over one-half quadrillion Btu greater. On the other hand, DRI projects stronger growth in petroleum and coal consumption in the industrial sector.

While all three forecasts expect modest growth in transportation demand, they have differing expectations for motor gasoline and diesel fuel use. The *AEO* is the only forecast that projects an actual decline in motor gasoline consumption as projected growth is more than offset by gains in fuel efficiency. However, this slight decline is offset by expected increases in diesel and residual fuel oil use. WEFA projects the weakest overall growth in transportation demand as a consequence of lower estimates for diesel fuel consumption but both WEFA and DRI project increasing gasoline use.

The *AEO 1989* projection of 38.1 quadrillion Btu for electric utility demand is substantially higher than the estimates of 35.8 and 34.2 by DRI and WEFA. The higher *AEO* projection for electric utility inputs is consistent with expected electricity consumption that exceeds the other forecasts. The *AEO* forecast includes heavier reliance on electricity by the residential, commercial, and industrial sectors. Almost half of this additional electricity is expected to be generated by new gas-consuming combined-cycle plants.

EIA Has Elevated Its Forecast of End-Use Consumption for 2000

In the *AEO 1989*, the level of total end-use energy consumption is 64.3 quadrillion Btu in the year 2000, nearly 1 quadrillion Btu higher than the level projected by EIA last year. For the most part, the higher consumption level in the current *AEO* can be attributed to a stronger estimate of vehicle-miles traveled. Personal travel is expected to increase by 2.1 percent per year over the forecast period. The lower world oil price estimate assumed by the *AEO 1989* is expected to encourage travel.

Of the four sectors evaluated, only the industrial sector had a consumption forecast that had actually declined from last year's *AEO*, with 23.9 quadrillion Btu compared to the earlier projection of 24.2. The lower industrial demand is the result of revised efficiency estimates for all fuels based on the recently published Manufacturing Energy Consumption Survey and as a result demand projections for both petroleum and natural gas are approximately 2 percent lower than in the previous forecast.

Table 4. Projections of U.S. Energy Demand by Sector for 2000

Sector	EIA Last Year	EIA *AEO 1989*	DRI	WEFA
End-Use Consumption (quadrillion Btu)				
Residential and Commercial				
Oil and LPG	2.4	2.4	2.1	2.5
Natural Gas	7.2	7.2	7.1	7.6
Electricity	7.2	7.4	6.9	7.1
Other	0.2	0.2	0.4	NA
Total	17.0	17.3	16.5	17.3
Industrial				
Oil and LPG	9.4	9.2	9.5	8.9
Natural Gas	7.7	7.5	6.3	6.4
Coal	2.8	2.8	3.0	2.5
Electricity	4.3	4.4	3.8	3.5
Total	24.2	23.9	22.6	21.2
Transportation				
Oil and LPG	21.4	22.3	23.6	21.7
Distillate	4.5	4.4	4.1	NA
Motor Gasoline	12.7	13.5	14.7	14.95
Natural Gas	0.6	0.6	0.5	0.5
Other	0.4	0.4	0.1	0.4
Total	22.3	23.2	24.3	22.7
Electric Utility				
Oil	2.8	2.6	2.4	1.4
Natural Gas	4.8	5.7	3.9	3.0
Coal	19.6	19.6	18.5	19.5
Nuclear Power	6.4	6.2	6.7	6.5
Other	4.1	4.1	4.3	4.2
Total	37.6	38.1	35.8	34.2
Total End-Use Consumption	63.4	64.3	63.4	61.1
Primary Energy Consumption	89.6	90.6	88.5	84.8
Electricity (All Sectors)	11.5	11.9	10.8	10.9
Primary Energy/GNP Ratio (thousand Btu per 1982 dollar)	17.6	16.9	16.9	16.0

NA = Not available.

[a]Includes residential kerosene and steam coal consumption plus commercial kerosene, liquefied petroleum gas, and steam coal consumption.

[b]Excludes renewable resource use in the residential, commercial, and industrial sectors.

[c]Includes electricity imports, hydroelectric, geothermal, and other (wood, solar, wind).

Sources: ***Last Year***: Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988). **DRI**: Data Resources, Inc., *Energy Review* (Lexington, MA, Autumn 1988). **WEFA**: Wharton Econometric Forecasting Associates, *Energy Analysis Quarterly* (Bala Cynwyd, PA, Summer 1988).

The current forecast includes a slightly higher estimate for electricity use across all sectors of 11.9 quadrillion Btu, compared to 11.5 in the previous forecast. It follows that the total inputs to electric utilities have also increased over last year's *AEO*, from 63.4 to 64.3 quadrillion Btu. However, the distribution of the fuels consumed by electric utilities has shifted between forecasts. The *AEO 1989* projects that utilities will use slightly less oil, coal, and nuclear power, and substantially more natural gas than estimated by EIA last year. Gas-fired capability is further augmented by

changes in the mix of new (unplanned) additions to capacity, favoring combined cycle over coal. A small decrease in nuclear generation is due to a downward revision in capacity additions resulting from nuclear plant postponements.

Supply Projections

EIA Presents Highest Supply Forecasts

With higher domestic supply, the EIA forecast is more optimistic than the alternative forecasts. While the *AEO 1989* projects total domestic production in the year 2000 at 69 quadrillion Btu, the DRI and WEFA projections are both substantially lower at 65 quadrillion Btu. The *AEO 1989* projects a slower decline in domestic oil production than either DRI or WEFA, but the major difference between the forecasts is that the *AEO* estimate for natural gas production is over 3 quadrillion Btu higher than the alternative forecasts. WEFA, which has the lowest estimate for domestic gas production, expects the highest level of natural gas imports.

EIA projects total domestic energy production to rise slowly over the forecast period from 66 quadrillion Btu in 1988 to 69 quadrillion Btu in 2000 (Table 5). This overall increase in total production is expected to occur despite a substantial reduction in annual crude oil production of over 2 quadrillion Btu. The *AEO 1989* projects natural gas production

Table 5. Comparison of U.S. Energy Supply and Demand Projections for 2000
(Quadrillion Btu)

Supply and Disposition	EIA Last Year	EIA *AEO 1989*	DRI	WEFA
Domestic Energy Production				
Oil	15.1	15.1	15.0	13.7
Natural Gas	17.9	19.0	15.8	15.5
Coal	25.2	25.5	24.2	25.4
Nuclear Power	6.4	6.2	6.7	6.5
Hydroelectric Power, Geothermal, and Other	3.4	3.4	3.4	3.8
Total	68.0	69.3	65.1	64.9
Net Imports				
Oil	21.2	21.6	22.8	20.7
Natural Gas	2.6	2.4	2.2	3.2
Coal, Coke, and Electricity	-1.6	-2.0	-1.9	NA
Total Available Supply[a]	89.6	90.6	88.5	NA
Adjustments	-0.7	0.3	0.4	
Consumption				
Petroleum Products	36.3	36.8	38.0	34.5
Natural Gas	20.2	20.9	17.8	18.3
Coal	22.6	22.5	21.7	22.9
Nuclear Power	6.4	6.2	6.7	6.5
Hydroelectric Power and Other	4.1	4.2	4.3	4.2
Total	89.6	90.6	88.5	86.4

NA = Not available.
[a]Total available supply is defined to include domestic production plus net imports, stocks changes, and other adjustments involved in equating total available supply with consumption.
Sources: ***Last Year***: Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988). **DRI**: Data Resources, Inc., *Energy Review* (Lexington, MA, Autumn 1988). **WEFA**: Wharton Econometric Forecasting Associates, *Energy Analysis Quarterly* (Bala Cynwyd, PA, Summer 1988).

to increase from 17.2 quadrillion Btu in 1988 to 19.0 quadrillion Btu in 2000, in contrast to the other two forecasts which estimate a decline in natural gas production relative to 1988.

Domestic crude oil production in *AEO 1989* is projected to fall from over 8 million barrels per day in 1988 to just under 6 million barrels per day in 2000 (Table 6). The *AEO 1989* domestic production forecast is between the WEFA and DRI estimates of 5.5 and 6.0 million barrels per day. Like the production forecast, the *AEO* estimate for petroleum consumption of 18.6 million barrels per day, also lies between the alternative forecasts. The DRI production estimate is slightly higher at 19.1 million barrels per day while the WEFA estimate is lower at 17.4. It follows that the *AEO 1989* projection for net petroleum imports of 10.2 million barrels per day is slightly lower than the DRI estimate but slightly higher than the WEFA estimate.

EIA's Energy Production Forecast Differs Little From Last Year's Outlook

The projection for total domestic energy production increased from 68.0 quadrillion Btu forecast by EIA last year to 69.3 quadrillion Btu in the current *AEO*. Nearly all of this change can be attributed to a higher estimate for natural gas production. The other components of production remained almost unchanged. In fact, the projections for oil, hydroelectric, geothermal, and other are exactly the same as last year's projections. Other differences include a marginal decline in nuclear power and a slight increase in coal production. Although the estimate for domestic coal consumption is marginally lower than that projected last year, a larger demand for coal exports is expected as a result of a stronger world market.

Table 6. Comparison of U.S. Petroleum Supply and Demand Projections for 2000

Projection	EIA Last Year	EIA *AEO 1989*	DRI	WEFA
Primary Supply (million barrels per day)				
Domestic Production				
Crude Oil	6.0	5.9	6.0	5.5
Natural Gas Liquids	1.7	1.9	1.5	1.4
Other/Processing Gain	0.7	0.7	0.7	0.7
Total	8.4	8.5	8.2	7.0
Net Imports				
Crude Oil	8.3	8.3	7.8	8.7
Refined Products	1.7	1.9	3.1	1.0
Total	10.0	10.2	10.8	9.7
Total Supply	18.3	18.6	19.1	17.4
Consumption by Fuel Type (million barrels per day)				
Motor Gasoline	6.8	7.3	7.9	7.8
Jet Fuel	1.6	1.7	1.8	1.9
Distillate Fuel Oil	3.7	3.7	3.3	2.8
Residual Fuel Oil	2.0	1.7	1.8	1.0
Other Petroleum Products	4.3	4.3	4.3	4.0
Total	18.3	18.6	19.1	17.4

Sources: ***Last Year***: Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988). **DRI**: Data Resources, Inc., *Energy Review* (Lexington, MA, Autumn 1988). **WEFA**: Wharton Econometric Forecasting Associates, *Energy Analysis Quarterly* (Bala Cynwyd, PA, Summer 1988).

Price Projections

Views Are Similar on World Oil Prices, But Other Energy Cost Outlooks Vary

The range in petroleum product price forecasts generally reflects the range of assumptions for the world oil price (Table 7). Since the *AEO 1989* and DRI both assumed a crude oil price in the range of $28 per barrel, compared to the WEFA assumption of $26 per barrel, EIA and DRI estimate generally higher product prices.

The effect of the lower world oil price assumption by WEFA can also be seen in the natural gas prices. As fuel switching capability makes natural gas consumption more responsive to oil prices, natural gas prices can be expected to follow oil prices more closely. Therefore, the spread between WEFA's natural gas price estimates and the alternative estimates is not surprising. The average wellhead price is estimated at $2.75 per thousand cubic feet compared with DRI and EIA estimates of $3.13 and $3.91, respectively (1988 dollars). This WEFA lower price perspective is seen in every sector for natural gas. Across sectors, the DRI forecast has the

Table 7. Comparison of Price Projections for 2000

Projection	EIA Last Year	EIA *AEO 1989*	DRI	WEFA
World Oil Price (dollars per barrel)	31.92	28.00	28.31	26.30
Petroleum Products				
Motor Gasoline (dollars per gallon)	1.44	1.32	1.30	0.93
Heating Oil (dollars per gallon)	1.46	1.07	1.13	[a]0.87
Residual (dollars per gallon)	30.65	27.85	26.68	23.35
Natural Gas (dollars per Mcf)				
Average Wellhead	4.15	3.91	[b]3.13	2.75
Residential	7.91	7.70	7.92	6.50
Commercial	6.41	6.87	6.78	5.94
Industrial	4.81	4.99	4.22	4.29
Electric Utility	4.83	4.28	3.83	3.34
Electricity (dollars per kWh)				
Residential	0.77	0.077	0.068	0.081
Commercial	0.73	0.072	0.063	0.079
Industrial	0.49	0.049	0.046	0.065
Coal (dollars per short ton)				
Minemouth	28.38	25.87	NA	28.83
Delivered Electric Utility	40.93	35.02	30.19	39.41

NA = Not available.
[a]No. 2 Distillate Fuel.
[b]Average acquisition price.
Sources: ***AEO 1987***: Energy Information Administration, *Annual Energy Outlook 1987*, DOE/EIA-0383(87) (Washington, DC, March 1988). **DRI**: Data Resources, Inc., *Energy Review* (Lexington, MA, Autumn 1988). **WEFA**: Wharton Econometric Forecasting Associates, *Energy Analysis Quarterly* (Bala Cynwyd, PA, Summer 1988).

broadest range of prices with residential gas over $7.92 per thousand cubic feet and electric utility prices at $3.83 per thousand cubic feet. The high and low prices in the *AEO 1989* forecast are also found in the electric utility and residential sectors; however, the *AEO* estimates have a tighter range, between $4.28 and $7.70.

With regard to electricity prices there are some obvious differences between the three forecasts. While *AEO 1989* and WEFA projections show a modest rise in all electricity prices, DRI expects an across-the-board decline. Another contrast between the forecasts has to do with the level of relative prices for each sector. The *AEO 1989* expects price differences across sectors to remain relatively stable, while WEFA predicts that the spread between residential and industrial prices will narrow somewhat, and DRI projects the gap to decline substantially.

EIA Energy Price Projections Are Lower Compared to Last Year's Outlook

EIA's world oil price projection for the year 2000 has been lowered from last year's forecast of $32 per barrel to $28 per barrel (1988 dollars). While the aggregate supply and demand projections were little changed, the lower oil price estimate can be explained in terms of a shift in EIA's evaluation of world petroleum production potential. Similar to earlier forecast, the *AEO 1989* expects an eventual decline in production by non-OPEC countries (including the Alaskan North Slope and the United Kingdom sector of the North Sea). In light of recent events, the current forecast projects that the non-OPEC decline will occur more gradually than assumed last year. In effect, *AEO 1989* projects a smaller OPEC market share in the year 2000 and reflects a slightly more competitive world market. Due to the lower world oil price projection, *AEO 1989* also estimates lower prices for key petroleum products, compared to last year's forecast.

The natural gas wellhead price of about $3.90 per thousand cubic feet for the year 2000 in the *AEO 1989* is lower than the price of $4.15 per thousand cubic feet forecast last year. The lower wellhead price reflects the lower world oil price projection as well as a more recent assessment of gas market supply potential. Similar to earlier EIA forecasts, *AEO 1989* expects the move toward more competitive gas markets to continue throughout the forecast period in the form of increased contract flexibility and a willingness to switch to alternative, price-competitive fuels. In the *AEO 1989*, however, the natural gas price forecast both begins at a lower level and increases less rapidly.

The current forecast is characterized by significant changes to the price of natural gas to each sector, reflecting a lower wellhead price estimate. Compared to last year's *AEO*, the current forecast estimates more electricity generation from natural gas and less generation from oil. The projection for coal-fired generation remains even with last year's estimate; however, the delivered price of coal has declined over $5 per short ton in response to the lower oil and natural gas prices.

Finally, projected electricity prices in *AEO 1989* are almost unchanged from those in last year's *AEO*.

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Appendix A

Base Case Forecasts

Appendix A

Base Case Forecasts

Table A1. Yearly Supply and Disposition Summary of Total Energy (Quadrillion Btu)

Supply and Disposition	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Crude Oil	18.4	17.7	17.3	16.9	16.2	15.4	14.6	14.0	13.5	13.1	12.8	12.7	12.6	12.5	12.5	-2.7
Natural Gas Plant Liquids	2.1	2.2	2.2	2.2	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	1.2
Natural Gas [1]	16.5	17.0	17.2	17.2	17.5	17.5	17.4	17.6	17.9	18.1	18.2	18.5	18.7	18.8	19.0	.9
Coal	19.5	20.2	20.7	20.8	21.4	21.7	22.2	22.7	23.1	23.6	23.6	24.1	24.6	25.1	25.5	1.8
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [2]	3.3	2.8	2.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	2.2
Total Production	**64.3**	**64.9**	**65.7**	**65.9**	**66.4**	**66.2**	**65.9**	**66.0**	**66.3**	**66.6**	**66.6**	**67.4**	**68.1**	**68.6**	**69.3**	**.4**
Imports																
Crude Oil [3]	9.0	10.1	11.0	11.9	13.3	14.1	15.2	15.7	16.1	16.6	17.2	17.2	17.4	17.9	18.3	4.3
Petroleum Products	4.4	4.3	4.2	4.5	4.6	4.8	5.0	5.0	5.1	5.2	5.3	5.3	5.3	5.4	5.5	2.2
Natural Gas [4]	.7	.9	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.1	2.2	2.3	6.0
Other Imports [5]	.4	.5	.5	.5	.5	.6	.6	.7	.7	.7	.8	.8	.8	.9	.9	5.1
Total Imports	**14.5**	**15.8**	**16.9**	**18.3**	**19.9**	**21.1**	**22.4**	**23.1**	**23.7**	**24.4**	**25.2**	**25.4**	**25.8**	**26.5**	**27.0**	**4.0**
Exports																
Coal	2.2	2.1	2.3	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.6	2.7	2.8	2.9	2.9	2.2
Petroleum	1.7	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	.2
Total Exports	**3.9**	**3.7**	**4.0**	**3.8**	**4.0**	**4.0**	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**	**1.4**
Adjustments [6]	**-.6**	**-.2**	**.8**	**.3**	**-.7**	**-.8**	**-.9**	**-.9**	**-.9**	**-1.0**	**-.9**	**-.8**	**-.9**	**-1.0**	**-1.0**	
Consumption																
Petroleum Products [7]	32.2	32.9	33.7	33.9	34.4	34.7	35.0	35.1	35.1	35.2	35.7	35.8	35.9	36.4	36.8	.7
Natural Gas	16.7	17.6	18.3	18.5	18.5	18.6	18.6	18.9	19.2	19.5	19.7	20.1	20.5	20.6	20.9	1.1
Coal	17.3	18.0	18.8	19.0	19.1	19.3	19.8	20.2	20.6	21.0	21.0	21.4	21.8	22.2	22.5	1.5
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [8]	3.6	3.3	3.1	3.6	3.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	2.6
Total Consumption	**74.3**	**76.8**	**79.4**	**80.6**	**81.6**	**82.5**	**83.3**	**84.2**	**84.9**	**85.8**	**86.6**	**87.5**	**88.5**	**89.5**	**90.6**	**1.1**
Net Imports - Petroleum	**11.7**	**12.8**	**13.6**	**14.8**	**16.2**	**17.2**	**18.4**	**19.0**	**19.5**	**20.0**	**20.7**	**20.8**	**21.0**	**21.6**	**22.0**	**4.1**
Prices (1988 dollars per unit)																
World Oil Price ($ per barrel)[9]	$14.92	$18.70	$14.70	$14.40	$15.00	$15.50	$15.90	$17.10	$18.90	$20.60	$22.50	$24.30	$26.00	$27.10	$28.00	5.5
Avg. Wellhead Price ($ per Mcf)	2.06	1.72	1.62	1.64	1.75	1.86	2.14	2.40	2.61	2.80	3.22	3.36	3.55	3.76	3.91	7.6
Avg. Coal Minemouth Price ($ per ton)	25.36	23.79	23.61	23.49	24.00	24.09	24.28	24.49	24.72	24.95	25.03	25.26	25.50	25.73	25.87	.8
Real GNP (billion 1982 dollars)	**3,722**	**3,847**	**4,001**	**4,116**	**4,217**	**4,326**	**4,434**	**4,540**	**4,648**	**4,757**	**4,875**	**4,976**	**5,095**	**5,230**	**5,368**	**2.5**

[1] Dry natural gas.
[2] Includes hydropower, geothermal power, wood, and waste.
[3] Includes imports of crude oil for the Strategic Petroleum Reserve.
[4] Represents net imports.
[5] Includes coal, net coal coke imports, and net electricity imports.
[6] Balancing item. Includes stock changes, unaccounted for supply, losses, and gains.
[7] Includes natural gas plant liquids and crude oil consumed as fuels.
[8] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, and solar thermal sources connected to electric utility distribution systems. Also includes net coal coke imports.
[9] Represents the cost of imported crude oil to U.S. refiners.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecast: Based on Run 635; File Creation Date 12/20/88.

Table A2. Consumption of Energy by Source and End-Use Sector
(Quadrillion Btu)

Sector and Fuel	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential																
Distillate [1]	1.10	1.10	1.16	1.19	1.15	1.12	1.10	1.07	1.04	1.02	0.99	0.97	0.95	0.93	0.91	-2.0
Liquefied Petroleum Gas	.41	.44	.45	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	-.1
Natural Gas	4.43	4.45	4.73	4.80	4.76	4.76	4.73	4.69	4.66	4.63	4.55	4.52	4.50	4.45	4.44	-.5
Coal	.07	.06	.07	.07	.06	.06	.06	.06	.06	.06	.06	.06	.06	.05	.05	-1.9
Electricity	2.79	2.90	3.01	3.03	3.10	3.17	3.24	3.31	3.38	3.45	3.51	3.58	3.63	3.69	3.74	1.8
Total	**8.80**	**8.96**	**9.41**	**9.53**	**9.52**	**9.56**	**9.56**	**9.58**	**9.58**	**9.60**	**9.56**	**9.57**	**9.58**	**9.57**	**9.59**	**.2**
Commercial																
Distillate [1]	.64	.64	.67	.69	.71	.72	.72	.72	.72	.72	.72	.72	.72	.73	.74	.8
Motor Gasoline	.11	.11	.11	.11	.12	.12	.12	.13	.13	.13	.13	.14	.14	.14	.15	2.5
Residual Fuel	.25	.23	.22	.22	.23	.23	.23	.22	.20	.19	.17	.16	.15	.14	.13	-4.0
Natural Gas	2.38	2.48	2.69	2.73	2.73	2.76	2.76	2.76	2.75	2.77	2.73	2.74	2.76	2.75	2.77	.3
Other Commercial [2]	.17	.18	.18	.18	.18	.18	.18	.17	.17	.17	.17	.17	.17	.17	.17	-.3
Electricity	2.46	2.58	2.69	2.80	2.88	2.96	3.04	3.13	3.22	3.30	3.38	3.46	3.54	3.62	3.69	2.7
Total	**6.01**	**6.22**	**6.55**	**6.74**	**6.85**	**6.96**	**7.04**	**7.13**	**7.19**	**7.28**	**7.31**	**7.40**	**7.48**	**7.55**	**7.66**	**1.3**
Industrial																
Distillate [1]	1.28	1.32	1.38	1.43	1.42	1.44	1.46	1.48	1.50	1.51	1.53	1.55	1.57	1.60	1.62	1.3
Liquefied Petroleum Gas	1.48	1.58	1.60	1.59	1.63	1.67	1.71	1.75	1.79	1.83	1.87	1.92	1.96	2.01	2.06	2.1
Motor Gasoline	.21	.21	.22	.22	.22	.23	.23	.23	.24	.24	.24	.25	.25	.26	.26	1.6
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	.83	.76	.74	.75	.76	.74	.72	.69	.67	.64	.62	.60	.58	.57	.55	-2.4
Natural Gas [3]	6.72	7.25	7.38	7.49	7.52	7.59	7.60	7.60	7.59	7.57	7.54	7.52	7.51	7.47	7.46	.1
Metallurgical Coal	.96	.99	1.08	1.04	1.03	1.03	1.03	1.02	1.00	.99	.98	.98	.97	.96	.95	-1.0
Steam Coal	1.67	1.69	1.69	1.69	1.69	1.70	1.70	1.71	1.72	1.73	1.74	1.77	1.79	1.81	1.84	.7
Other Industrial [4]	3.18	3.57	3.72	3.57	3.65	3.65	3.65	3.62	3.57	3.54	3.53	3.50	3.50	3.54	3.58	-.3
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.3
Electricity	2.76	2.88	3.00	3.09	3.17	3.28	3.38	3.49	3.60	3.72	3.85	3.99	4.12	4.26	4.40	3.2
Total	**20.06**	**21.19**	**21.66**	**21.75**	**22.01**	**22.26**	**22.44**	**22.56**	**22.66**	**22.78**	**22.96**	**23.14**	**23.35**	**23.59**	**23.87**	**.8**
Transportation																
Distillate [1]	3.30	3.37	3.52	3.64	3.75	3.85	3.94	3.98	4.03	4.07	4.13	4.18	4.23	4.29	4.35	1.8
Jet Fuel	2.68	2.82	2.96	3.06	3.11	3.16	3.21	3.24	3.27	3.30	3.33	3.35	3.38	3.43	3.49	1.4
Motor Gasoline	13.17	13.50	13.75	13.94	13.96	13.81	13.70	13.59	13.50	13.43	13.40	13.36	13.37	13.43	13.50	-.2
Residual Fuel	.82	.74	.71	.73	.74	.76	.77	.79	.81	.82	.84	.86	.87	.89	.91	2.1
Natural Gas	.50	.53	.57	.56	.51	.51	.51	.52	.53	.54	.54	.55	.56	.57	.57	.1
Other Transportation [5]	.27	.28	.30	.30	.31	.31	.32	.33	.33	.34	.34	.35	.35	.36	.37	1.6
Total	**20.75**	**21.24**	**21.82**	**22.23**	**22.38**	**22.40**	**22.46**	**22.45**	**22.47**	**22.50**	**22.59**	**22.65**	**22.77**	**22.97**	**23.20**	**.5**
Electric Utilities																
Distillate	.08	.09	.11	.09	.05	.06	.09	.11	.13	.12	.16	.19	.20	.21	.22	5.9
Residual Fuel	1.37	1.17	1.21	1.07	1.27	1.46	1.67	1.76	1.76	1.84	2.19	2.22	2.16	2.27	2.32	5.6
Natural Gas	2.69	2.92	2.92	2.92	2.96	3.00	3.04	3.31	3.71	4.01	4.39	4.80	5.12	5.34	5.66	5.7
Steam Coal	14.45	15.19	15.84	16.06	16.23	16.39	16.89	17.31	17.68	18.11	18.16	18.47	18.84	19.23	19.55	1.6
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [6]	3.60	3.29	3.00	3.53	3.71	3.80	3.83	3.87	3.91	3.94	4.00	4.03	4.07	4.10	4.13	2.7
Total	**26.67**	**27.57**	**28.72**	**29.30**	**30.00**	**30.70**	**31.51**	**32.40**	**33.25**	**34.10**	**34.99**	**35.83**	**36.58**	**37.37**	**38.10**	**2.4**
Primary Energy Consumption																
Distillate [1]	6.40	6.52	6.84	7.04	7.08	7.19	7.30	7.37	7.42	7.45	7.53	7.61	7.68	7.76	7.84	1.1
Jet Fuel	2.68	2.82	2.96	3.06	3.11	3.16	3.21	3.24	3.27	3.30	3.33	3.35	3.38	3.43	3.49	1.4
Liquefied Petroleum Gas	2.01	2.15	2.18	2.16	2.20	2.24	2.28	2.32	2.36	2.41	2.45	2.49	2.54	2.59	2.64	1.6
Motor Gasoline	13.49	13.82	14.08	14.27	14.30	14.16	14.05	13.95	13.87	13.80	13.78	13.75	13.76	13.83	13.91	-.1
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	3.26	2.89	2.87	2.77	2.99	3.19	3.39	3.46	3.44	3.49	3.82	3.84	3.76	3.87	3.92	2.6
Natural Gas	16.72	17.64	18.28	18.49	18.48	18.63	18.64	18.89	19.24	19.51	19.75	20.14	20.45	20.58	20.90	1.1
Metallurgical Coal	.96	.99	1.08	1.04	1.03	1.03	1.03	1.02	1.00	.99	.98	.98	.97	.96	.95	-1.0
Steam Coal	16.30	17.04	17.70	17.91	18.08	18.25	18.75	19.18	19.55	19.99	20.05	20.38	20.79	21.20	21.54	1.6
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Net Coal Coke Imports	-.02	.01	.05	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	-4.8
Hydropower/Misc. [7]	7.02	7.11	7.00	7.37	7.64	7.74	7.77	7.77	7.77	7.78	7.83	7.84	7.88	7.95	8.03	1.2
Total Consumption	**74.27**	**76.81**	**79.45**	**80.62**	**81.58**	**82.47**	**83.34**	**84.16**	**84.94**	**85.78**	**86.64**	**87.53**	**88.46**	**89.47**	**90.57**	**1.1**
Electricity (all sectors)	**8.02**	**8.38**	**8.72**	**8.94**	**9.17**	**9.42**	**9.67**	**9.95**	**10.22**	**10.48**	**10.77**	**11.04**	**11.30**	**11.58**	**11.85**	**2.6**

[1] Includes kerosene.
[2] Includes liquefied petroleum gas and coal.
[3] Includes lease and plant fuel.
[4] Includes still gas, lubricants, waxes, asphalt, special naphthas, petroleum coke, and net coal coke imports.
[5] Includes electricity, liquefied petroleum gas, lubricants, and waxes.
[6] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports.
[7] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports and minor petroleum products.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A3. Price of Energy by Source and End-Use Sector
(1988 Dollars per Million Btu)

Sector and Fuel	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential	**11.57**	**11.17**	**10.83**	**10.60**	**11.08**	**11.26**	**11.48**	**11.66**	**11.91**	**12.12**	**12.52**	**12.77**	**13.03**	**13.37**	**13.60**	**1.9**
Primary Energy	6.27	5.80	5.47	5.40	5.62	5.77	5.98	6.22	6.47	6.67	7.09	7.30	7.48	7.79	7.95	3.2
Petroleum Products	7.10	6.59	5.96	5.73	6.24	6.50	6.78	7.14	7.49	7.85	8.33	8.70	9.07	9.41	9.68	4.1
Distillate Fuel	6.40	5.97	5.80	5.53	5.99	6.20	6.43	6.72	7.01	7.29	7.72	8.03	8.34	8.63	8.87	3.6
Liquefied Petroleum Gas	8.94	8.13	6.38	6.28	6.90	7.26	7.66	8.16	8.63	9.12	9.69	10.15	10.64	11.05	11.34	4.9
Natural Gas	6.03	5.57	5.34	5.32	5.45	5.56	5.76	5.97	6.19	6.35	6.75	6.91	7.05	7.34	7.48	2.8
Steam Coal	3.07	2.81	2.73	2.74	2.77	2.78	2.80	2.83	2.87	2.90	2.93	2.96	3.00	3.04	3.06	1.0
Electricity	23.01	22.40	22.21	21.75	22.39	22.34	22.23	21.94	21.90	21.84	21.87	21.96	22.14	22.26	22.43	.1
Commercial	**11.96**	**11.47**	**11.28**	**11.46**	**11.54**	**11.66**	**11.84**	**11.97**	**12.21**	**12.39**	**12.76**	**13.00**	**13.25**	**13.55**	**13.76**	**1.7**
Primary Energy	4.91	4.66	4.53	4.47	4.53	4.66	4.86	5.09	5.34	5.54	5.94	6.15	6.34	6.63	6.79	3.4
Petroleum Products	4.42	4.64	4.61	4.42	4.38	4.59	4.82	5.15	5.49	5.82	6.28	6.64	6.99	7.29	7.54	4.2
Distillate Fuel	4.13	4.31	4.72	4.50	4.32	4.52	4.75	5.03	5.32	5.60	6.02	6.33	6.63	6.92	7.15	3.5
Residual Fuel	2.72	3.20	2.44	2.45	2.62	2.76	2.90	3.14	3.38	3.62	3.94	4.19	4.41	4.56	4.67	5.6
Other Petroleum [1]	7.82	7.49	6.65	6.38	6.65	6.96	7.26	7.72	8.17	8.62	9.10	9.55	9.99	10.30	10.56	3.9
Natural Gas	5.27	4.79	4.61	4.59	4.70	4.80	4.99	5.19	5.41	5.56	5.96	6.12	6.25	6.54	6.67	3.1
Steam Coal	1.76	1.60	1.56	1.56	1.58	1.59	1.60	1.62	1.64	1.66	1.68	1.69	1.72	1.74	1.75	1.0
Electricity	22.15	21.06	20.98	21.27	21.18	21.12	21.03	20.74	20.70	20.65	20.68	20.77	20.95	21.08	21.24	.1
Industrial	**5.02**	**4.79**	**4.55**	**4.62**	**4.63**	**4.77**	**4.95**	**5.15**	**5.39**	**5.61**	**5.93**	**6.17**	**6.41**	**6.66**	**6.82**	**3.4**
Primary Energy	3.40	3.31	3.01	2.99	2.99	3.13	3.31	3.54	3.79	4.01	4.34	4.56	4.77	4.99	5.12	4.5
Petroleum Products	4.02	4.22	3.62	3.56	3.46	3.68	3.89	4.23	4.58	4.91	5.28	5.62	5.95	6.18	6.34	4.8
Distillate Fuel	4.11	4.41	3.91	3.73	4.42	4.63	4.86	5.14	5.43	5.71	6.14	6.45	6.76	7.05	7.28	5.3
Liquefied Petroleum Gas	6.21	5.55	4.35	4.54	4.30	4.65	5.04	5.53	5.99	6.48	7.04	7.48	7.97	8.37	8.64	5.9
Motor Gasoline	7.24	7.20	6.98	6.58	6.65	6.93	7.18	7.61	8.05	8.48	8.92	9.37	9.78	10.06	10.30	3.3
Residual Fuel	2.22	2.65	2.24	2.10	2.11	2.27	2.41	2.65	2.89	3.13	3.44	3.69	3.90	4.05	4.16	5.3
Other Petroleum [2]	3.41	3.81	3.34	3.26	2.93	3.09	3.21	3.50	3.80	4.07	4.32	4.60	4.85	4.96	5.04	3.5
Natural Gas	3.25	2.84	2.79	2.81	2.91	3.00	3.19	3.39	3.61	3.76	4.15	4.31	4.44	4.72	4.85	4.7
Metallurgical Coal	2.02	1.80	1.76	1.76	1.78	1.78	1.80	1.81	1.83	1.85	1.87	1.89	1.91	1.92	1.94	.8
Steam Coal	1.74	1.57	1.54	1.54	1.56	1.56	1.58	1.59	1.61	1.62	1.63	1.65	1.66	1.68	1.69	.8
Hydroelectric Power	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	.0
Electricity	15.19	14.16	14.11	14.42	14.33	14.29	14.19	13.90	13.85	13.79	13.79	13.88	14.06	14.22	14.35	.1
Transportation	**6.66**	**6.85**	**6.42**	**6.11**	**6.40**	**6.63**	**6.86**	**7.23**	**7.61**	**7.98**	**8.39**	**8.78**	**9.14**	**9.39**	**9.61**	**3.4**
Primary Energy	6.65	6.84	6.41	6.10	6.39	6.63	6.85	7.22	7.60	7.97	8.38	8.77	9.13	9.39	9.60	3.4
Petroleum Products	6.65	6.84	6.41	6.10	6.39	6.63	6.85	7.22	7.60	7.97	8.38	8.77	9.13	9.39	9.60	3.4
Distillate Fuel	6.18	6.47	6.13	5.98	6.47	6.68	6.91	7.19	7.48	7.76	8.18	8.49	8.79	9.08	9.31	3.5
Jet Fuel	4.20	4.19	3.81	3.71	3.76	3.96	4.15	4.47	4.80	5.12	5.49	5.83	6.14	6.37	6.56	4.6
Motor Gasoline	7.30	7.46	6.98	6.59	6.91	7.18	7.43	7.86	8.31	8.74	9.17	9.62	10.04	10.31	10.55	3.5
Residual Fuel	2.06	2.55	2.26	1.99	2.00	2.16	2.30	2.54	2.78	3.01	3.33	3.57	3.79	3.94	4.04	5.0
Other Petroleum [3]	19.87	20.19	19.70	19.58	19.42	19.58	19.70	19.99	20.29	20.57	20.82	21.10	21.36	21.46	21.53	.7
Electricity	20.83	20.09	19.86	20.06	20.13	20.00	19.90	19.62	19.63	19.62	19.72	19.89	20.09	20.26	20.26	.2
Total Energy																
Primary Energy - Four Sectors	5.28	5.22	4.88	4.74	4.89	5.07	5.27	5.56	5.87	6.15	6.53	6.82	7.09	7.34	7.52	3.7
Electricity	20.05	19.15	19.04	19.07	19.22	19.15	19.04	18.74	18.68	18.61	18.60	18.67	18.82	18.93	19.06	.0
Electric Utilities																
Fossil Fuel Average	**1.87**	**1.78**	**1.66**	**1.63**	**1.72**	**1.75**	**1.81**	**1.88**	**1.96**	**2.03**	**2.17**	**2.26**	**2.33**	**2.41**	**2.47**	**3.4**
Petroleum Products	2.63	3.15	2.51	2.47	2.62	2.79	2.95	3.22	3.48	3.70	4.03	4.31	4.55	4.72	4.84	5.6
Distillate Fuel	4.20	4.12	3.96	3.75	4.16	4.36	4.59	4.87	5.16	5.46	5.88	6.20	6.49	6.78	7.01	4.9
Residual Fuel	2.53	3.07	2.38	2.36	2.56	2.72	2.87	3.11	3.35	3.58	3.90	4.15	4.37	4.53	4.64	5.7
Natural Gas	2.44	2.32	2.18	2.21	2.25	2.28	2.49	2.72	2.89	3.10	3.42	3.64	3.81	4.02	4.16	5.5
Steam Coal	1.69	1.56	1.50	1.46	1.54	1.55	1.56	1.58	1.60	1.61	1.62	1.64	1.65	1.67	1.68	1.0
Hydroelectric Power	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.0
Nuclear Power	.80	.80	.78	.76	.73	.70	.67	.65	.63	.62	.60	.59	.59	.58	.57	-2.5
Average Price to All Users																
Petroleum Products	5.77	5.95	5.48	5.27	5.44	5.65	5.85	6.20	6.56	6.90	7.26	7.62	7.98	8.21	8.40	3.6
Distillate Fuel	5.58	5.72	5.46	5.27	5.75	5.96	6.19	6.46	6.75	7.03	7.45	7.75	8.06	8.34	8.57	3.8
Jet Fuel	4.20	4.19	3.81	3.71	3.76	3.96	4.15	4.47	4.80	5.12	5.49	5.83	6.14	6.37	6.56	4.6
Liquefied Petroleum Gas	6.92	6.22	4.87	4.99	4.96	5.30	5.68	6.16	6.62	7.10	7.65	8.08	8.56	8.96	9.22	5.5
Motor Gasoline	7.30	7.45	6.98	6.59	6.90	7.18	7.42	7.86	8.30	8.73	9.17	9.61	10.03	10.30	10.55	3.5
Residual Fuel	2.35	2.84	2.32	2.20	2.31	2.49	2.64	2.89	3.13	3.37	3.70	3.95	4.16	4.32	4.43	5.6
Other Petroleum Products	4.33	4.70	4.32	4.24	3.91	4.08	4.22	4.52	4.84	5.13	5.39	5.68	5.94	6.05	6.13	3.0
Natural Gas	4.17	3.75	3.65	3.66	3.74	3.83	4.02	4.20	4.37	4.51	4.86	5.00	5.12	5.37	5.48	3.5
Coal [4]	1.72	1.58	1.52	1.49	1.56	1.57	1.58	1.60	1.61	1.63	1.64	1.66	1.67	1.68	1.69	.9
Electricity	20.05	19.15	19.04	19.07	19.22	19.15	19.04	18.74	18.68	18.61	18.60	18.67	18.82	18.93	19.06	.0

[1] Includes liquefied petroleum gas and motor gasoline.
[2] Includes petrochemical feedstocks, still gas, lubricants, waxes, asphalt, special naphthas, and petroleum coke.
[3] Includes liquefied petroleum gas, lubricants, and waxes.
[4] Includes steam coal and metallurgical coal.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A4. Supply and Disposition of Electricity
(Quadrillion Btu)

Fuel Consumption and Disposition	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electric Utilities																
Fuel Inputs																
Oil																
Distillate	0.08	0.09	0.11	0.09	0.05	0.06	0.09	0.11	0.13	0.12	0.16	0.19	0.20	0.21	0.22	5.9
Residual	1.37	1.17	1.21	1.07	1.27	1.46	1.67	1.76	1.76	1.84	2.19	2.22	2.16	2.27	2.32	5.6
Natural Gas	2.69	2.92	2.92	2.92	2.96	3.00	3.04	3.31	3.71	4.01	4.39	4.80	5.12	5.34	5.66	5.7
Steam Coal	14.45	15.19	15.84	16.06	16.23	16.39	16.89	17.31	17.68	18.11	18.16	18.47	18.84	19.23	19.55	1.8
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [1]	3.23	2.81	2.59	3.10	3.26	3.29	3.30	3.31	3.34	3.35	3.36	3.37	3.38	3.38	3.38	2.3
Total Fuel Inputs	**26.30**	**27.09**	**28.31**	**28.87**	**29.55**	**30.19**	**30.97**	**31.85**	**32.68**	**33.51**	**34.35**	**35.16**	**35.89**	**36.65**	**37.35**	**2.3**
Net Imports (fuel input equiv.)	.37	.48	.42	.43	.45	.51	.53	.55	.57	.59	.64	.66	.69	.72	.75	5.1
Total Electricity Inputs	**26.67**	**27.57**	**28.72**	**29.30**	**30.00**	**30.70**	**31.51**	**32.40**	**33.25**	**34.10**	**34.99**	**35.83**	**36.58**	**37.37**	**38.10**	**2.4**
Disposition																
Total Electricity Inputs	26.67	27.57	28.72	29.30	30.00	30.70	31.51	32.40	33.25	34.10	34.99	35.83	36.58	37.37	38.10	2.4
Minus Conversion Losses	18.18	18.79	19.56	19.96	20.47	20.94	21.49	22.10	22.69	23.27	23.88	24.45	24.95	25.45	25.92	2.4
Generation	**8.49**	**8.78**	**9.16**	**9.34**	**9.53**	**9.76**	**10.01**	**10.30**	**10.56**	**10.83**	**11.11**	**11.38**	**11.64**	**11.91**	**12.18**	**2.4**
Plus Nonutility Purchases	.13	.16	.19	.23	.26	.27	.29	.30	.32	.33	.34	.36	.37	.39	.40	6.3
Plus Net Imports (electricity equiv.)	.12	.16	.14	.14	.15	.17	.18	.18	.19	.19	.21	.22	.23	.24	.25	5.1
Minus Trans. & Dist. Losses	.72	.72	.77	.78	.76	.78	.80	.83	.85	.87	.89	.92	.94	.96	.98	2.1
Electricity Sales	**8.02**	**8.38**	**8.72**	**8.94**	**9.17**	**9.42**	**9.67**	**9.95**	**10.22**	**10.48**	**10.77**	**11.04**	**11.30**	**11.58**	**11.85**	**2.6**
Electricity Sales by End-Use Sector																
Residential	2.79	2.90	3.01	3.03	3.10	3.17	3.24	3.31	3.38	3.45	3.51	3.58	3.63	3.69	3.74	1.8
Commercial/Other [2]	2.47	2.60	2.70	2.82	2.90	2.97	3.06	3.15	3.23	3.32	3.40	3.48	3.55	3.63	3.71	2.7
Industrial	2.76	2.88	3.00	3.09	3.17	3.28	3.38	3.49	3.60	3.72	3.85	3.99	4.12	4.26	4.40	3.2
Total Electricity Sales	**8.02**	**8.38**	**8.72**	**8.94**	**9.17**	**9.42**	**9.67**	**9.95**	**10.22**	**10.48**	**10.77**	**11.04**	**11.30**	**11.58**	**11.85**	**2.6**
Nonutilities																
Fuel Inputs for Generation [3]																
Oil	.01	.01	.01	.01	.01	.01	.02	.02	.02	.02	.02	.02	.02	.03	.03	8.2
Gas	.26	.30	.35	.39	.44	.46	.48	.51	.53	.56	.59	.61	.64	.67	.70	6.1
Coal	.15	.17	.19	.21	.23	.24	.26	.27	.29	.30	.32	.34	.36	.38	.40	6.4
Nonfossil [4]	.33	.35	.38	.40	.43	.44	.46	.48	.50	.52	.55	.57	.60	.62	.65	4.7
Disposition of Generated Electricity																
Sales to Utilities	.13	.16	.19	.23	.26	.27	.29	.30	.32	.33	.34	.36	.37	.39	.40	6.3
Own Use	.25	.27	.28	.29	.31	.33	.34	.36	.38	.39	.42	.44	.46	.49	.51	5.1

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Includes street lighting and sales to the transportation sector.
[3] Represents energy content of fuel required for generation.
[4] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 635; File Creation Date 12/20/88.

Table A5. Electric Utility Summer Capability and Generation
(Capability in Million Kilowatts)
(Generation in Billion Kilowatthours)

Capability and Generation	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Net Capability [1]																
Coal Steam	291.7	292.8	294.6	296.8	296.9	297.9	299.0	299.1	299.8	301.7	302.9	306.5	311.0	315.4	320.6	0.7
Other Fossil Steam	146.4	145.3	144.7	144.5	144.4	141.0	140.6	139.5	136.5	134.5	133.0	131.6	130.5	129.4	127.9	-1.0
Combined Cycle	5.1	5.1	5.1	5.2	5.3	5.3	6.0	6.8	6.9	7.0	12.8	19.9	26.2	34.0	45.0	19.8
Turbine/Diesel	44.3	44.3	45.0	45.6	45.4	48.5	49.6	50.8	52.0	53.3	54.7	56.5	58.8	60.8	63.3	2.9
Nuclear Power	85.4	93.6	95.1	98.7	99.8	103.0	103.0	103.0	103.0	103.0	103.0	103.0	104.1	104.1	104.0	.7
Hydropower/Other [2]	93.4	93.7	94.3	94.4	95.3	96.0	97.0	97.6	98.4	98.6	98.9	98.9	99.0	99.1	99.2	.4
Total Capability	**666.3**	**674.8**	**678.7**	**685.2**	**687.1**	**691.7**	**695.2**	**696.7**	**696.7**	**698.2**	**705.2**	**716.5**	**729.5**	**742.8**	**759.9**	**.9**
Generation by Plant Type																
Coal Steam	1,386	1,464	1,523	1,548	1,568	1,580	1,629	1,672	1,709	1,753	1,759	1,790	1,829	1,869	1,901	1.9
Other Fossil Steam	363	366	372	354	371	385	400	426	454	482	519	521	519	520	512	2.7
Combined Cycle	14	17	17	16	22	22	25	29	29	29	55	88	116	152	201	23.1
Turbine/Diesel	8	9	9	9	7	12	17	23	31	35	44	56	59	62	64	17.7
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [2]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,807**	**2,860**	**2,934**	**3,017**	**3,095**	**3,173**	**3,255**	**3,335**	**3,411**	**3,492**	**3,570**	**2.4**
Generation by Fuel Type																
Coal	1,386	1,464	1,523	1,548	1,568	1,580	1,629	1,672	1,709	1,753	1,759	1,790	1,829	1,869	1,901	1.9
Natural Gas	249	273	272	271	278	279	282	307	341	367	405	446	481	509	549	6.0
Oil	137	118	126	109	121	140	161	171	173	178	214	219	214	224	229	5.1
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [3]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,807**	**2,860**	**2,934**	**3,017**	**3,095**	**3,173**	**3,255**	**3,335**	**3,411**	**3,492**	**3,570**	**2.4**
Nonutilities																
Generation by Fuel Type [4]																
Residual Oil	1	1	2	2	2	2	2	3	3	3	3	3	4	4	4	8.2
Natural Gas	42	48	56	63	70	74	77	81	85	90	94	98	103	107	112	6.1
Steam Coal	21	24	27	30	33	34	36	39	41	43	45	48	51	53	56	6.4
Nonfossil [5]	48	51	55	59	62	65	68	71	74	77	80	84	88	91	96	4.7
Generation by Use																
Sales to Utilities	37	47	57	66	76	80	84	88	92	97	101	105	109	114	118	6.3
Own Use	75	78	82	86	91	95	100	105	110	116	122	128	135	142	150	5.1

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2] Includes other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[3] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[4] Individual fuel inputs converted to Kilowatthours based on average heat rate for each respective fuel.
[5] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	Base Case														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Additions															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	2,671	5,266	5,484	5,456	6,245	39,189
Combined Cycle [2]	0	14	20	153	0	681	767	164	102	5,771	7,104	6,264	7,868	10,932	39,840
Turbines [3]	263	709	589	58	3,165	1,196	1,254	1,263	1,381	1,474	1,876	2,245	2,052	2,548	19,812
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total New Capability	**10,930**	**5,504**	**6,817**	**2,960**	**10,120**	**4,058**	**3,030**	**3,735**	**4,996**	**10,150**	**14,288**	**15,196**	**15,478**	**19,828**	**116,162**
Announced/Planned Construction [4]															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	2,382	2,188	672	142	602	20,052
Combined Cycle [2]	0	14	20	153	0	681	767	164	102	288	28	102	0	0	2,319
Turbines [3]	263	709	589	58	153	58	66	90	64	225	286	434	278	77	3,087
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total Planned	**10,930**	**5,504**	**6,817**	**2,960**	**7,108**	**2,920**	**1,842**	**2,562**	**3,679**	**3,130**	**2,544**	**2,410**	**522**	**781**	**42,779**
Additional Needed Capability [5]															
Nuclear Power [1]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	289	3,078	4,812	5,314	5,643	19,137
Combined Cycle [2]	0	0	0	0	0	0	0	0	0	5,483	7,076	6,162	7,868	10,932	37,521
Turbines [3]	0	0	0	0	3,012	1,138	1,188	1,173	1,317	1,249	1,590	1,811	1,774	2,471	16,725
Total Additional Needed	**0**	**0**	**0**	**0**	**3,012**	**1,138**	**1,188**	**1,173**	**1,317**	**7,020**	**11,744**	**12,786**	**14,956**	**19,047**	**73,383**

[1] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes all new capability announced by the electric utility industry.
[5] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A7. Electric Utility Sales, Prices, and Price Components
(Billion Kilowatthours)
(1988 Dollars per Thousand Kilowatthours)

Sales, Prices, and Price Component	Base Case														Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electricity Sales by End-Use Sector																
Residential	818	850	884	889	909	928	948	971	991	1,011	1,030	1,048	1,063	1,081	1,097	1.8
Commercial/Other [1]	725	761	792	826	849	872	896	923	947	972	996	1,020	1,042	1,065	1,088	2.7
Industrial	808	845	881	904	930	960	991	1,023	1,056	1,089	1,129	1,169	1,208	1,247	1,289	3.2
Total Electricity Sales	**2,351**	**2,456**	**2,556**	**2,619**	**2,689**	**2,760**	**2,835**	**2,917**	**2,994**	**3,072**	**3,156**	**3,236**	**3,313**	**3,394**	**3,473**	**2.6**
Prices [2]																
Residential	78.53	76.45	75.80	74.23	76.39	76.21	75.86	74.87	74.72	74.52	74.61	74.91	75.54	75.94	76.54	.1
Commercial/Other [1]	75.54	71.84	71.56	72.55	72.23	72.05	71.72	70.75	70.62	70.43	70.53	70.86	71.48	71.92	72.45	.1
Industrial	51.83	48.31	48.13	49.19	48.90	48.76	48.41	47.42	47.26	47.04	47.06	47.36	47.97	48.53	48.96	.1
All Sectors	**68.43**	**65.33**	**64.95**	**65.05**	**65.57**	**65.35**	**64.96**	**63.94**	**63.74**	**63.49**	**63.46**	**63.69**	**64.21**	**64.61**	**65.03**	**.0**
Price Components																
Capital Component [3]	32.48	30.92	30.20	31.54	31.17	30.87	30.10	28.62	27.91	27.07	26.00	25.45	25.42	25.22	25.14	-1.5
Fuel Component [4]	16.98	16.68	15.88	15.46	15.54	15.75	16.26	16.91	17.55	18.22	19.42	20.27	20.87	21.53	22.07	2.8
O&M Component [5]	18.97	19.08	18.86	18.92	18.86	18.73	18.60	18.42	18.29	18.19	18.04	17.97	17.92	17.86	17.82	-.5
Total Price [2]	**68.43**	**66.68**	**64.94**	**65.92**	**65.57**	**65.35**	**64.96**	**63.95**	**63.75**	**63.49**	**63.47**	**63.69**	**64.21**	**64.61**	**65.03**	**.0**

[1] Includes consumption for street and highway lighting, other public authorities, and railways.
[2] Prices for 1988 to 2000 are estimated from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry.
[3] Represents the cost to the utility of capital assets needed to promote reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[4] Includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[5] 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.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 635; File Creation Date 12/20/88.

Table A8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1] (1988 dollars per barrel)	**14.92**	**18.70**	**14.70**	**14.40**	**15.00**	**15.50**	**15.90**	**17.10**	**18.90**	**20.60**	**22.50**	**24.30**	**26.00**	**27.10**	**28.00**	**5.5**
Production																
Crude Oil [2]	8.68	8.35	8.18	7.97	7.64	7.25	6.87	6.59	6.37	6.17	6.05	6.00	5.94	5.90	5.89	-2.7
Alaska	1.87	1.96	2.03	2.01	1.96	1.80	1.62	1.51	1.41	1.29	1.21	1.16	1.06	.98	.91	-6.5
Lower 48	6.81	6.39	6.15	5.95	5.68	5.45	5.25	5.08	4.96	4.88	4.84	4.84	4.87	4.92	4.98	-1.7
Natural Gas Liquids	1.55	1.60	1.61	1.62	1.67	1.72	1.71	1.73	1.75	1.77	1.78	1.82	1.84	1.84	1.87	1.2
Other Domestic	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.6
Processing Gain [3]	.62	.64	.66	.66	.66	.65	.64	.64	.63	.62	.62	.62	.62	.62	.63	-.5
Total Production	**10.90**	**10.65**	**10.51**	**10.31**	**10.03**	**9.69**	**9.29**	**9.02**	**8.82**	**8.63**	**8.52**	**8.50**	**8.46**	**8.43**	**8.45**	**-1.8**
Imports (Including SPR [4])																
Crude Oil	4.18	4.67	5.12	5.54	6.16	6.55	7.06	7.31	7.50	7.71	7.97	7.99	8.09	8.33	8.49	4.3
Refined Products	2.05	2.00	1.96	2.09	2.16	2.23	2.30	2.34	2.37	2.40	2.46	2.47	2.48	2.51	2.54	2.2
Total Imports	**6.22**	**6.67**	**7.08**	**7.63**	**8.31**	**8.78**	**9.36**	**9.65**	**9.86**	**10.11**	**10.43**	**10.46**	**10.57**	**10.84**	**11.03**	**3.8**
Exports																
Crude Oil	.15	.15	.17	.17	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	1.3
Refined Products	.63	.61	.64	.62	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.0
Total Exports	**.78**	**.76**	**.80**	**.79**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.2**
Net Imports	**5.44**	**5.91**	**6.28**	**6.84**	**7.49**	**7.96**	**8.53**	**8.83**	**9.04**	**9.28**	**9.60**	**9.64**	**9.75**	**10.02**	**10.20**	**4.1**
Primary Stock Changes [5]																
Net Withdrawals	-.15	.04	.04	.01	-.04	.00	-.03	.00	.00	-.01	-.04	-.01	-.01	-.04	-.04	
SPR [4] Fill Rate (-)	-.05	-.08	-.05	-.05	-.08	-.08	-.08	-.08	-.08	-.08	-.03	.00	.00	.00	.00	
Total Primary Supply [6]	**16.14**	**16.52**	**16.78**	**17.11**	**17.40**	**17.57**	**17.72**	**17.77**	**17.78**	**17.83**	**18.06**	**18.13**	**18.19**	**18.41**	**18.61**	**.9**
Refined Petroleum Products																
Motor Gasoline	7.03	7.21	7.34	7.44	7.46	7.38	7.33	7.27	7.23	7.20	7.19	7.17	7.18	7.21	7.26	-.1
Jet Fuel [7]	1.31	1.37	1.44	1.49	1.52	1.54	1.56	1.58	1.59	1.61	1.62	1.63	1.65	1.67	1.70	1.4
Distillate Fuel [8]	3.01	3.07	3.22	3.32	3.33	3.39	3.44	3.47	3.49	3.51	3.54	3.58	3.61	3.65	3.69	1.1
Residual Fuel	1.42	1.26	1.25	1.20	1.30	1.38	1.47	1.50	1.49	1.51	1.66	1.67	1.63	1.68	1.70	2.6
Other Petroleum Products [9]	3.52	3.76	3.76	3.75	3.83	3.87	3.91	3.94	3.96	3.99	4.04	4.07	4.12	4.19	4.26	1.1
Total Product Supplied	**16.29**	**16.67**	**17.01**	**17.20**	**17.44**	**17.57**	**17.72**	**17.76**	**17.78**	**17.82**	**18.05**	**18.12**	**18.19**	**18.40**	**18.61**	**.8**
Refined Petroleum Products Supplied by Sector																
Residential/Commercial	1.35	1.37	1.41	1.43	1.43	1.42	1.41	1.39	1.37	1.36	1.34	1.32	1.31	1.30	1.30	-.7
Industrial	4.09	4.30	4.30	4.33	4.40	4.45	4.49	4.51	4.53	4.56	4.60	4.64	4.68	4.76	4.84	1.0
Transportation	10.22	10.46	10.73	10.94	11.03	11.04	11.05	11.04	11.04	11.05	11.09	11.11	11.16	11.26	11.37	.5
Electric Utilities	.63	.55	.58	.51	.57	.67	.77	.82	.83	.86	1.03	1.05	1.03	1.08	1.11	5.6
Total Consumption	**16.29**	**16.67**	**17.01**	**17.20**	**17.44**	**17.57**	**17.72**	**17.76**	**17.78**	**17.82**	**18.05**	**18.12**	**18.19**	**18.40**	**18.61**	**.8**
Discrepancy [10]	**-.15**	**-.15**	**-.23**	**-.10**	**-.04**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.01**	**.00**	**.01**	**.01**	
Net Disposition [11]	**16.14**	**16.52**	**16.78**	**17.11**	**17.40**	**17.57**	**17.72**	**17.77**	**17.78**	**17.83**	**18.06**	**18.13**	**18.19**	**18.41**	**18.61**	**.9**

[1] Represents the cost of imported crude oil to U.S. refiners.
[2] Includes lease condensate.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] SPR is the Strategic Petroleum Reserve.
[5] A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[6] Equals total production plus net imports plus net stock withdrawals minus SPR fill rate.
[7] Includes naphtha and kerosene type.
[8] Includes kerosene.
[9] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, plant condensate, pentanes plus, asphalt and road oil, still gas, special naphthas, petroleum coke, unfinished oils, and miscellaneous petroleum products.
[10] Represents the difference between total primary supply and total consumption.
[11] Represents the sum of total consumption and discrepancy.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A9. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet)
(1988 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Dry Gas Production	15.99	16.54	16.71	16.71	16.94	17.01	16.93	17.09	17.35	17.54	17.67	17.98	18.20	18.25	18.49	0.9
Supplemental Gas [1]	.11	.10	.17	.18	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	-4.3
Net Imports	**.69**	**.94**	**1.15**	**1.32**	**1.44**	**1.52**	**1.61**	**1.70**	**1.79**	**1.87**	**1.98**	**2.06**	**2.15**	**2.23**	**2.31**	**6.0**
Net Storage Withdrawals [2]	**-.15**	**.00**	**.04**	**.05**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	
Total Supply [3]	**16.65**	**17.57**	**18.07**	**18.26**	**18.48**	**18.63**	**18.64**	**18.89**	**19.24**	**19.51**	**19.75**	**20.14**	**20.45**	**20.58**	**20.90**	**1.2**
Consumption by Sector																
Residential	4.30	4.32	4.59	4.66	4.62	4.62	4.59	4.56	4.52	4.49	4.42	4.39	4.37	4.32	4.31	-.5
Commercial [4]	2.31	2.41	2.61	2.65	2.65	2.68	2.68	2.68	2.67	2.68	2.65	2.66	2.68	2.67	2.69	.3
Industrial	5.60	5.89	6.15	6.24	6.29	6.36	6.37	6.36	6.34	6.31	6.27	6.24	6.21	6.16	6.14	.0
Lease & Plant Fuel [5]	.92	1.15	1.01	1.03	1.01	1.01	1.01	1.02	1.03	1.04	1.05	1.06	1.08	1.09	1.10	.7
Transportation [6]	.48	.52	.55	.54	.49	.50	.50	.51	.51	.52	.53	.54	.54	.55	.56	.1
Electric Utilities	2.61	2.84	2.83	2.83	2.88	2.91	2.95	3.22	3.61	3.89	4.26	4.66	4.97	5.18	5.50	5.7
Total Consumption	**16.23**	**17.13**	**17.75**	**17.95**	**17.94**	**18.08**	**18.10**	**18.34**	**18.68**	**18.94**	**19.17**	**19.55**	**19.86**	**19.98**	**20.29**	**1.1**
Unaccounted for [7]	**.41**	**.45**	**.32**	**.31**	**.54**	**.54**	**.54**	**.55**	**.56**	**.57**	**.58**	**.59**	**.60**	**.60**	**.61**	
Average Wellhead Price	**2.06**	**1.72**	**1.62**	**1.64**	**1.75**	**1.86**	**2.14**	**2.40**	**2.61**	**2.80**	**3.22**	**3.36**	**3.55**	**3.76**	**3.91**	**7.6**
Average Price by Sector																
Residential	6.21	5.74	5.50	5.48	5.61	5.73	5.94	6.15	6.38	6.54	6.95	7.12	7.26	7.56	7.70	2.8
Commercial [4]	5.43	4.93	4.75	4.73	4.84	4.94	5.14	5.35	5.57	5.73	6.14	6.30	6.44	6.74	6.87	3.1
Industrial	3.35	2.93	2.87	2.90	3.00	3.09	3.29	3.49	3.71	3.87	4.28	4.44	4.57	4.87	4.99	4.7
Electric Utilities	2.52	2.39	2.25	2.27	2.32	2.35	2.57	2.80	2.98	3.19	3.53	3.75	3.92	4.14	4.28	5.5
Average to All Sectors [8]	**4.36**	**3.93**	**3.81**	**3.82**	**3.91**	**4.00**	**4.19**	**4.37**	**4.55**	**4.70**	**5.05**	**5.19**	**5.31**	**5.57**	**5.68**	**3.4**

[1] Includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane-air mixtures.
[2] Includes net withdrawals of dry natural gas from underground storage and liquefied natural gas. A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[3] Total supply represents the sum of dry gas production, supplemental gas, net imports, and net storage withdrawals.
[4] Includes deliveries to municipalities and other public authorities for use in schools and other institutions.
[5] Represents natural gas used in gathering systems and processing plants.
[6] Represents natural gas used to fuel compressors in pipeline pumping stations.
[7] Represents the difference between total supply and total consumption.
[8] Weighted average price. The weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding. Commercial and industrial natural gas prices for 1989, reflect base case values from PC-AEO Model run 635.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A10. Coal Supply, Disposition, and Prices
(Million Short Tons)
(1988 Dollars per Short Ton)

Supply, Disposition, and Prices	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Production [1]	890	919	941	946	977	990	1,018	1,039	1,058	1,082	1,084	1,107	1,130	1,152	1,171	1.8
Imports	2	2	2	2	3	4	4	4	5	5	5	5	6	6	7	10.1
Exports [2]	86	80	86	82	85	87	89	91	93	95	98	102	105	108	112	2.2
Net Imports	-83	-78	-84	-80	-82	-83	-85	-87	-88	-90	-93	-97	-99	-102	-105	1.9
Net Storage Withdrawals [3]	-4	-6	17	17	-2	-5	-7	-6	-5	-6	-1	-4	-5	-5	-4	
Total Supply [4]	803	834	875	882	894	903	927	947	965	987	990	1,006	1,026	1,045	1,062	1.6
Consumption by Sector																
Residential/Commercial	8	7	7	7	7	7	7	7	7	7	7	7	7	7	6	-.9
Industrial	76	75	75	75	75	76	76	76	77	77	78	79	80	81	83	.8
Coking Plants	36	37	39	39	39	39	38	38	37	37	37	36	36	36	36	-.8
Electric Utilities	685	718	750	760	773	782	806	826	844	866	869	884	903	921	937	1.9
Total Consumption	804	837	872	882	894	903	927	947	965	987	990	1,006	1,026	1,045	1,062	1.7
Discrepancy [5]	-1	-3	3	0	0	0	0	0	0	0	0	0	0	0	0	
Average Minemouth Price [6]	25.36	23.79	23.61	23.49	24.00	24.09	24.28	24.49	24.72	24.95	25.03	25.26	25.50	25.73	25.87	.8
Delivered Price by Sector																
Residential/Commercial	52.08	48.19	46.32	46.33	46.78	46.86	47.16	47.56	48.06	48.59	48.92	49.41	49.94	50.45	50.81	.8
Industrial	38.20	34.76	34.92	34.87	35.18	35.14	35.39	35.70	35.92	36.32	36.55	36.92	37.14	37.44	37.54	.6
Coking Plants	54.18	48.01	47.15	47.12	47.60	47.76	48.12	48.56	49.09	49.65	50.02	50.55	51.06	51.50	51.89	.8
Electric Utilities	35.49	32.95	31.74	31.01	32.43	32.51	32.77	33.09	33.40	33.76	33.93	34.24	34.53	34.80	35.02	.8
Average to All Sectors [7]	36.74	33.91	32.82	32.17	33.43	33.49	33.73	34.02	34.31	34.66	34.83	35.14	35.42	35.68	35.88	.9

[1] Includes anthracite, bituminous coal, and lignite.
[2] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces.
[3] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. A negative (-) result represents an increase to inventories. A positive result represents a withdrawal from inventories.
[4] Represents the sum of production, net imports, and net storage withdrawals.
[5] Represents the difference between total supply and total consumption.
[6] Free on board (F.O.B.) mines.
[7] Weighted average prices. The weights used are consumption values by sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); *Quarterly Coal Report*, DOE/EIA-0121(88/2Q); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Table A11. National Macroeconomic Indicators

Macroeconomic Indicators	Base Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1]																
1988 dollars per barrel	14.92	18.70	14.70	14.40	15.00	15.50	15.90	17.10	18.90	20.60	22.50	24.30	26.00	27.10	28.00	5.5
Nominal dollars per barrel	14.00	18.13	14.70	14.93	16.33	17.75	19.15	21.68	25.21	28.91	33.29	37.81	42.47	46.36	49.98	10.7
1982 dollars per barrel	12.29	15.40	12.11	11.86	12.36	12.77	13.10	14.09	15.57	16.97	18.53	20.02	21.42	22.32	23.06	5.5
Economic Variables																
Real GNP (billion 1982 dollars)	3,722	3,847	4,001	4,116	4,217	4,326	4,434	4,540	4,648	4,757	4,875	4,976	5,095	5,230	5,368	2.5
Real Disposable Income (billion 1982 dollars)	2,641	2,687	2,787	2,860	2,923	2,987	3,051	3,114	3,178	3,241	3,310	3,373	3,444	3,521	3,600	2.2
Real Disposable Income per Capita (thousand 1982 dollars)	10.9	11.0	11.3	11.5	11.7	11.8	12.0	12.2	12.3	12.5	12.6	12.8	13.0	13.2	13.4	1.4
GNP Implicit Price Deflator (1982=1.00)	1.139	1.177	1.214	1.259	1.322	1.390	1.462	1.539	1.619	1.704	1.796	1.889	1.983	2.077	2.167	4.9
Unemployment Rate (percent)	7.0	6.2	5.4	5.2	5.3	5.5	5.6	5.9	6.1	6.4	6.5	6.7	7.0	7.1	7.2	
Population, Noninstitutional (million persons)	241.3	243.5	245.6	247.8	250.0	252.1	254.2	256.2	258.1	259.9	261.7	263.5	264.6	266.8	268.4	.7
New AA Bond Rate (percent per annum)	8.94	9.50	10.26	11.19	10.54	10.58	10.39	9.98	10.05	10.08	10.17	10.17	10.11	9.98	9.77	
Energy Usage Indicators																
Gross Energy Use (quadrillion Btu)	74.3	76.8	79.4	80.6	81.6	82.5	83.3	84.2	84.9	85.8	86.6	87.5	88.5	89.5	90.6	1.1
Gross Energy Use per Capita (million Btu per person)	307.8	315.5	323.4	325.3	326.3	327.1	327.9	328.5	329.1	330.0	331.0	332.2	334.3	335.4	337.5	.4
Gross Energy Use per Dollar of GNP (thousand Btu per 1982 dollar)	20.0	20.0	19.9	19.6	19.3	19.1	18.8	18.5	18.3	18.0	17.8	17.6	17.4	17.1	16.9	-1.3
Gross Petroleum and Natural Gas Use per Dollar of GNP (thousand Btu per 1982 dollar)	13.2	13.1	12.9	12.7	12.5	12.3	12.1	11.9	11.7	11.5	11.4	11.2	11.1	10.9	10.7	-1.6
Energy/GNP Rate of Change (percent)																
1985-1990	-1.1															
1985-1995	-1.3															
1985-2000	-1.3															
1990-1995	-1.4															
1995-2000	-1.3															
1988-2000	-1.3															

[1] Represents the cost of imported crude oil to U.S. refiners.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Data Resources, Inc., USMODEL database (October 1988); Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 635; File Creation Date 12/20/88.

Appendix B

Low World Oil Price Forecasts

Appendix B

Low World Oil Price Case Forecasts

Table B1. Yearly Supply and Disposition Summary of Total Energy (Quadrillion Btu)

Supply and Disposition	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Crude Oil	18.4	17.7	17.3	16.5	16.0	15.0	14.1	13.4	12.8	12.3	11.8	11.5	11.2	11.0	10.9	-3.8
Natural Gas Plant Liquids	2.1	2.2	2.2	2.2	2.3	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	2.6	2.6	1.4
Natural Gas [1]	16.5	17.0	17.2	17.2	17.7	17.7	17.7	17.9	18.1	18.2	18.5	18.7	18.9	19.1	19.4	1.0
Coal	19.5	20.2	20.7	20.8	21.4	21.7	22.3	22.7	23.1	23.6	23.9	24.4	24.8	25.2	25.6	1.8
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [2]	3.3	2.8	2.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	2.2
Total Production	**64.3**	**64.9**	**65.7**	**65.5**	**66.4**	**66.1**	**65.8**	**65.9**	**65.9**	**66.0**	**66.2**	**66.7**	**67.1**	**67.5**	**68.1**	**.3**
Imports																
Crude Oil [3]	9.0	10.1	11.0	12.6	14.0	15.1	16.4	17.0	17.8	18.4	19.3	19.8	20.4	20.9	21.2	5.6
Petroleum Products	4.4	4.3	4.2	4.5	4.8	5.0	5.2	5.3	5.4	5.5	5.7	5.8	5.8	5.9	6.0	2.9
Natural Gas [4]	.7	.9	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.1	2.2	2.3	5.8
Other Imports [5]	.4	.5	.5	.5	.5	.6	.6	.7	.7	.7	.8	.8	.8	.9	.9	5.1
Total Imports	**14.5**	**15.8**	**16.9**	**19.0**	**20.8**	**22.2**	**23.8**	**24.6**	**25.6**	**26.5**	**27.6**	**28.4**	**29.2**	**29.9**	**30.4**	**5.0**
Exports																
Coal	2.2	2.1	2.3	2.2	2.2	2.3	2.3	2.4	2.4	2.5	2.6	2.7	2.8	2.9	3.0	2.3
Petroleum	1.7	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	.2
Total Exports	**3.9**	**3.7**	**4.0**	**3.8**	**4.0**	**4.0**	**4.1**	**4.1**	**4.2**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.7**	**1.5**
Adjustments [6]	**-.6**	**-.2**	**.8**	**.4**	**-.8**	**-.8**	**-1.0**	**-.9**	**-1.0**	**-1.0**	**-.9**	**-.9**	**-.9**	**-1.0**	**-1.0**	
Consumption																
Petroleum Products [7]	32.2	32.9	33.7	34.3	35.1	35.6	36.0	36.1	36.3	36.6	37.2	37.6	38.0	38.5	38.7	1.2
Natural Gas	16.7	17.6	18.3	18.5	18.7	18.8	18.9	19.2	19.4	19.6	20.0	20.3	20.5	20.8	21.2	1.2
Coal	17.3	18.0	18.8	19.0	19.1	19.3	19.8	20.2	20.6	21.0	21.2	21.6	21.9	22.3	22.5	1.5
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [8]	3.6	3.3	3.1	3.6	3.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	2.6
Total Consumption	**74.3**	**76.8**	**79.4**	**81.0**	**82.5**	**83.5**	**84.6**	**85.5**	**86.4**	**87.3**	**88.6**	**89.7**	**90.9**	**91.9**	**92.9**	**1.3**
Net Imports - Petroleum	**11.7**	**12.8**	**13.6**	**15.5**	**17.0**	**18.4**	**19.8**	**20.5**	**21.4**	**22.2**	**23.2**	**23.8**	**24.5**	**25.1**	**25.4**	**5.4**
Prices (1988 dollars per unit)																
World Oil Price ($ per barrel)[9]	$14.92	$18.70	$14.70	$12.40	$12.89	$13.40	$13.80	$14.80	$15.80	$16.70	$17.70	$18.70	$19.50	$20.40	$21.70	3.3
Avg. Wellhead Price ($ per Mcf)	2.06	1.72	1.62	1.64	1.69	1.73	1.99	2.23	2.40	2.49	2.79	2.90	3.14	3.34	3.52	6.7
Avg. Coal Minemouth Price ($ per ton)	25.36	23.79	23.61	23.26	23.76	23.86	24.07	24.28	24.45	24.61	24.72	24.93	25.08	25.24	25.42	.6
Real GNP (billion 1982 dollars)	**3,722**	**3,847**	**4,001**	**4,116**	**4,221**	**4,344**	**4,463**	**4,571**	**4,677**	**4,779**	**4,905**	**5,015**	**5,140**	**5,276**	**5,410**	**2.5**

[1] Dry natural gas.
[2] Includes hydropower, geothermal power, wood, and waste.
[3] Includes imports of crude oil for the Strategic Petroleum Reserve.
[4] Represents net imports.
[5] Includes coal, net coal coke imports, and net electricity imports.
[6] Balancing item. Includes stock changes, unaccounted for supply, losses, and gains.
[7] Includes natural gas plant liquids and crude oil consumed as fuels.
[8] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, and solar thermal sources connected to electric utility distribution systems. Also includes net coal coke imports.
[9] Represents the cost of imported crude oil to U.S. refiners.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecast: Based on Run 636; File Creation Date 12/20/88.

Table B2. Consumption of Energy by Source and End-Use Sector
(Quadrillion Btu)

Sector and Fuel	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential																
Distillate [1]	1.10	1.10	1.16	1.22	1.16	1.13	1.10	1.08	1.05	1.03	1.01	0.99	0.97	0.95	0.93	-1.8
Liquefied Petroleum Gas	.41	.44	.45	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	-.1
Natural Gas	4.43	4.45	4.73	4.80	4.78	4.80	4.77	4.74	4.71	4.70	4.65	4.63	4.59	4.54	4.52	-.4
Coal	.07	.06	.07	.07	.06	.06	.06	.06	.06	.06	.06	.06	.06	.05	.05	-1.9
Electricity	2.79	2.90	3.01	3.04	3.11	3.17	3.24	3.33	3.40	3.47	3.54	3.60	3.66	3.73	3.79	1.9
Total	**8.80**	**8.96**	**9.41**	**9.56**	**9.55**	**9.61**	**9.62**	**9.65**	**9.66**	**9.71**	**9.70**	**9.72**	**9.72**	**9.72**	**9.74**	**.3**
Commercial																
Distillate [1]	.64	.64	.67	.71	.72	.73	.73	.73	.73	.74	.74	.74	.75	.76	.76	1.1
Motor Gasoline	.11	.11	.11	.11	.12	.12	.12	.13	.13	.13	.14	.14	.15	.15	.15	2.7
Residual Fuel	.25	.23	.22	.23	.25	.25	.25	.24	.23	.22	.21	.20	.19	.18	.17	-1.9
Natural Gas	2.38	2.48	2.69	2.73	2.75	2.79	2.80	2.80	2.80	2.83	2.82	2.83	2.84	2.83	2.85	.5
Other Commercial [2]	.17	.18	.18	.18	.18	.18	.18	.18	.18	.18	.17	.17	.17	.17	.17	-.2
Electricity	2.46	2.58	2.69	2.81	2.89	2.96	3.05	3.14	3.23	3.31	3.40	3.48	3.56	3.65	3.72	2.8
Total	**6.01**	**6.22**	**6.55**	**6.78**	**6.90**	**7.04**	**7.12**	**7.22**	**7.30**	**7.41**	**7.48**	**7.57**	**7.66**	**7.74**	**7.83**	**1.5**
Industrial																
Distillate [1]	1.28	1.32	1.38	1.44	1.43	1.46	1.48	1.50	1.52	1.54	1.56	1.59	1.61	1.64	1.66	1.5
Liquefied Petroleum Gas	1.48	1.58	1.60	1.59	1.63	1.67	1.71	1.75	1.79	1.83	1.88	1.92	1.97	2.01	2.06	2.1
Motor Gasoline	.21	.21	.22	.22	.22	.23	.23	.24	.24	.24	.25	.25	.26	.26	.27	1.8
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	.83	.76	.74	.83	.79	.77	.76	.73	.71	.68	.67	.66	.64	.63	.61	-1.5
Natural Gas [3]	6.72	7.25	7.38	7.49	7.71	7.74	7.79	7.81	7.80	7.80	7.84	7.86	7.86	7.83	7.81	.5
Metallurgical Coal	.96	.99	1.08	1.04	1.04	1.05	1.05	1.05	1.03	1.01	1.01	1.01	1.00	1.00	.98	-.8
Steam Coal	1.67	1.69	1.69	1.70	1.72	1.73	1.74	1.74	1.74	1.74	1.76	1.78	1.80	1.81	1.83	.7
Other Industrial [4]	3.18	3.57	3.72	3.68	3.85	3.84	3.84	3.80	3.77	3.77	3.79	3.79	3.83	3.86	3.88	.4
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.3
Electricity	2.76	2.88	3.00	3.08	3.19	3.31	3.43	3.53	3.64	3.74	3.91	4.06	4.20	4.33	4.46	3.3
Total	**20.06**	**21.19**	**21.66**	**21.96**	**22.48**	**22.73**	**22.99**	**23.11**	**23.24**	**23.37**	**23.72**	**23.99**	**24.27**	**24.51**	**24.72**	**1.1**
Transportation																
Distillate [1]	3.30	3.37	3.52	3.64	3.77	3.88	3.98	4.03	4.07	4.11	4.18	4.24	4.30	4.36	4.42	1.9
Jet Fuel	2.68	2.82	2.96	3.09	3.14	3.21	3.26	3.30	3.34	3.37	3.42	3.46	3.51	3.56	3.61	1.7
Motor Gasoline	13.17	13.50	13.75	14.05	14.17	14.06	13.99	13.90	13.87	13.84	13.89	13.92	14.00	14.09	14.14	.2
Residual Fuel	.82	.74	.71	.73	.74	.76	.78	.80	.81	.83	.85	.87	.89	.91	.92	2.2
Natural Gas	.50	.53	.57	.56	.52	.52	.53	.54	.54	.55	.56	.57	.58	.59	.60	.4
Other Transportation [5]	.27	.28	.30	.30	.31	.32	.32	.33	.33	.34	.35	.35	.36	.37	.37	1.7
Total	**20.75**	**21.24**	**21.82**	**22.37**	**22.66**	**22.75**	**22.86**	**22.89**	**22.98**	**23.05**	**23.25**	**23.42**	**23.64**	**23.88**	**24.07**	**.8**
Electric Utilities																
Distillate	.08	.09	.1	.09	.05	.06	.09	.11	.13	.12	.15	.18	.20	.21	.22	5.9
Residual Fuel	1.37	1.17	1.21	1.07	1.40	1.73	1.94	2.02	2.15	2.32	2.66	2.80	2.89	2.95	2.93	7.7
Natural Gas	2.69	2.92	2.92	2.92	2.95	2.96	3.03	3.29	3.55	3.76	4.12	4.41	4.67	5.03	5.41	5.3
Steam Coal	14.45	15.19	15.84	16.06	16.19	16.33	16.85	17.29	17.67	18.08	18.29	18.66	18.98	19.29	19.58	1.8
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [6]	3.60	3.29	3.00	3.53	3.71	3.80	3.83	3.87	3.91	3.94	4.00	4.03	4.07	4.10	4.13	2.7
Total	**26.67**	**27.57**	**28.72**	**29.30**	**30.08**	**30.87**	**31.73**	**32.62**	**33.47**	**34.30**	**35.32**	**36.21**	**37.01**	**37.80**	**38.49**	**2.5**
Primary Energy Consumption																
Distillate [1]	6.40	6.52	6.84	7.10	7.13	7.26	7.38	7.45	7.51	7.54	7.64	7.75	7.84	7.92	7.99	1.3
Jet Fuel	2.68	2.82	2.96	3.09	3.14	3.21	3.26	3.30	3.34	3.37	3.42	3.46	3.51	3.56	3.61	1.7
Liquefied Petroleum Gas	2.01	2.15	2.18	2.16	2.20	2.25	2.29	2.33	2.37	2.41	2.45	2.50	2.55	2.60	2.64	1.6
Motor Gasoline	13.49	13.82	14.08	14.39	14.51	14.41	14.34	14.26	14.24	14.21	14.27	14.32	14.40	14.50	14.56	.3
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	3.26	2.89	2.87	2.85	3.19	3.52	3.73	3.79	3.91	4.06	4.39	4.53	4.61	4.67	4.64	4.1
Natural Gas	16.72	17.64	18.28	18.49	18.71	18.81	18.91	19.17	19.40	19.64	19.99	20.31	20.55	20.82	21.18	1.2
Metallurgical Coal	.96	.99	1.08	1.04	1.04	1.05	1.05	1.05	1.03	1.01	1.01	1.01	1.00	1.00	.98	-.8
Steam Coal	16.30	17.04	17.70	17.93	18.07	18.22	18.75	19.18	19.57	19.98	20.20	20.60	20.93	21.26	21.56	1.7
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Net Coal Coke Imports	-.02	.01	.05	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	-4.8
Hydropower/Misc. [7]	7.02	7.11	7.00	7.49	7.83	7.92	7.96	7.96	7.97	8.01	8.09	8.14	8.21	8.28	8.34	1.5
Total Consumption	**74.27**	**76.81**	**79.45**	**81.02**	**82.48**	**83.53**	**84.59**	**85.47**	**86.36**	**87.30**	**88.59**	**89.75**	**90.85**	**91.91**	**92.85**	**1.3**
Electricity (all sectors)	**8.02**	**8.38**	**8.72**	**8.94**	**9.19**	**9.46**	**9.74**	**10.02**	**10.28**	**10.54**	**10.87**	**11.16**	**11.44**	**11.73**	**11.99**	**2.7**

[1] Includes kerosene.
[2] Includes liquefied petroleum gas and coal.
[3] Includes lease and plant fuel.
[4] Includes still gas, lubricants, waxes, asphalt, special naphthas, petroleum coke, and net coal coke imports.
[5] Includes electricity, liquefied petroleum gas, lubricants, and waxes.
[6] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports.
[7] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports and minor petroleum products.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B3. Price of Energy by Source and End-Use Sector
(1988 Dollars per Million Btu)

Sector and Fuel	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential	**11.57**	**11.17**	**10.83**	**10.22**	**10.92**	**11.09**	**11.30**	**11.45**	**11.65**	**11.76**	**12.03**	**12.24**	**12.48**	**12.78**	**13.03**	**1.6**
Primary Energy	6.27	5.80	5.47	5.17	5.42	5.60	5.80	6.01	6.21	6.31	6.59	6.75	6.95	7.22	7.41	2.6
Petroleum Products	7.10	6.59	5.96	5.37	5.93	6.21	6.49	6.80	7.05	7.26	7.56	7.82	8.06	8.33	8.63	3.1
Distillate Fuel	6.40	5.97	5.80	5.20	5.76	6.01	6.26	6.52	6.72	6.89	7.20	7.44	7.66	7.89	8.16	2.9
Liquefied Petroleum Gas	8.94	8.13	6.38	5.85	6.36	6.71	7.07	7.50	7.81	8.10	8.39	8.66	8.95	9.25	9.62	3.5
Natural Gas	6.03	5.57	5.34	5.14	5.29	5.44	5.61	5.79	5.99	6.05	6.32	6.47	6.65	6.93	7.09	2.4
Steam Coal	3.07	2.81	2.73	2.71	2.74	2.75	2.78	2.81	2.84	2.87	2.89	2.92	2.95	2.97	3.01	.8
Electricity	23.01	22.40	22.21	21.05	22.32	22.22	22.10	21.79	21.70	21.55	21.50	21.55	21.66	21.70	21.86	-.1
Commercial	**11.96**	**11.47**	**11.28**	**11.33**	**11.38**	**11.45**	**11.61**	**11.72**	**11.90**	**11.97**	**12.21**	**12.40**	**12.63**	**12.89**	**13.12**	**1.3**
Primary Energy	4.91	4.66	4.53	4.36	4.39	4.49	4.68	4.88	5.08	5.18	5.45	5.62	5.81	6.07	6.26	2.7
Petroleum Products	4.42	4.64	4.61	4.06	4.07	4.31	4.54	4.83	5.06	5.26	5.56	5.81	6.04	6.29	6.58	3.0
Distillate Fuel	4.13	4.31	4.72	4.18	4.10	4.34	4.59	4.84	5.04	5.21	5.51	5.74	5.95	6.19	6.45	2.6
Residual Fuel	2.72	3.20	2.44	2.14	2.32	2.49	2.63	2.84	2.97	3.10	3.27	3.41	3.51	3.63	3.79	3.8
Other Petroleum [1]	7.82	7.49	6.65	5.97	6.17	6.47	6.76	7.16	7.45	7.73	7.99	8.26	8.51	8.77	9.11	2.7
Natural Gas	5.27	4.79	4.61	4.59	4.63	4.67	4.85	5.02	5.21	5.27	5.54	5.68	5.86	6.13	6.29	2.6
Steam Coal	1.76	1.60	1.56	1.55	1.57	1.58	1.59	1.61	1.62	1.64	1.65	1.67	1.69	1.70	1.72	.8
Electricity	22.15	21.06	20.98	21.18	21.10	21.01	20.89	20.59	20.50	20.36	20.31	20.36	20.47	20.54	20.68	-.1
Industrial	**5.02**	**4.79**	**4.55**	**4.44**	**4.40**	**4.53**	**4.69**	**4.86**	**5.02**	**5.13**	**5.32**	**5.49**	**5.67**	**5.88**	**6.08**	**2.4**
Primary Energy	3.40	3.31	3.01	2.83	2.77	2.88	3.04	3.25	3.42	3.53	3.72	3.86	4.00	4.19	4.37	3.1
Petroleum Products	4.02	4.22	3.62	3.19	3.03	3.24	3.44	3.74	3.93	4.11	4.29	4.47	4.62	4.78	5.02	2.8
Distillate Fuel	4.11	4.41	3.91	3.40	4.20	4.45	4.69	4.95	5.15	5.32	5.62	5.86	6.08	6.31	6.57	4.4
Liquefied Petroleum Gas	6.21	5.55	4.35	4.11	3.75	4.09	4.45	4.87	5.17	5.45	5.73	6.00	6.28	6.57	6.93	4.0
Motor Gasoline	7.24	7.20	6.98	6.19	6.21	6.48	6.72	7.11	7.39	7.66	7.92	8.19	8.42	8.66	9.00	2.1
Residual Fuel	2.22	2.65	2.24	1.80	1.83	2.00	2.14	2.35	2.49	2.61	2.78	2.92	3.02	3.13	3.29	3.3
Other Petroleum [2]	3.41	3.81	3.34	2.92	2.48	2.62	2.73	2.98	3.11	3.23	3.30	3.41	3.47	3.55	3.72	.9
Natural Gas	3.25	2.84	2.79	2.81	2.85	2.87	3.04	3.22	3.41	3.46	3.73	3.86	4.04	4.32	4.47	4.0
Metallurgical Coal	2.02	1.80	1.76	1.74	1.76	1.77	1.78	1.80	1.81	1.83	1.84	1.86	1.87	1.89	1.91	.7
Steam Coal	1.74	1.57	1.54	1.53	1.54	1.55	1.56	1.58	1.59	1.60	1.61	1.63	1.64	1.65	1.66	.6
Hydroelectric Power	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	.0
Electricity	15.19	14.16	14.11	14.34	14.26	14.18	14.07	13.76	13.66	13.52	13.46	13.51	13.62	13.73	13.84	-.2
Transportation	**6.66**	**6.85**	**6.42**	**5.73**	**6.01**	**6.25**	**6.47**	**6.81**	**7.05**	**7.27**	**7.52**	**7.77**	**7.97**	**8.19**	**8.48**	**2.4**
Primary Energy	6.65	6.84	6.41	5.72	6.00	6.24	6.47	6.80	7.04	7.27	7.51	7.76	7.96	8.18	8.48	2.4
Petroleum Products	6.65	6.84	6.41	5.72	6.00	6.24	6.47	6.80	7.04	7.27	7.51	7.76	7.96	8.18	8.48	2.4
Distillate Fuel	6.18	6.47	6.13	5.65	6.25	6.50	6.74	6.99	7.19	7.36	7.66	7.89	8.11	8.34	8.60	2.9
Jet Fuel	4.20	4.19	3.81	3.35	3.40	3.61	3.81	4.09	4.29	4.47	4.69	4.89	5.06	5.25	5.51	3.1
Motor Gasoline	7.30	7.46	6.98	6.20	6.46	6.73	6.97	7.37	7.64	7.91	8.17	8.44	8.67	8.91	9.25	2.4
Residual Fuel	2.06	2.55	2.26	1.68	1.72	1.89	2.03	2.24	2.37	2.50	2.67	2.81	2.91	3.02	3.18	2.9
Other Petroleum [3]	19.87	20.19	19.70	19.23	18.95	19.09	19.19	19.44	19.57	19.69	19.75	19.85	19.90	19.97	20.13	.2
Electricity	20.83	20.09	19.86	19.90	19.98	19.83	19.72	19.42	19.34	19.23	19.23	19.30	19.45	19.64	19.68	-.1
Total Energy																
Primary Energy - Four Sectors	5.28	5.22	4.88	4.48	4.60	4.77	4.96	5.23	5.43	5.59	5.82	6.01	6.19	6.41	6.64	2.6
Electricity	20.05	19.15	19.04	18.78	19.14	19.03	18.89	18.58	18.47	18.32	18.23	18.25	18.33	18.39	18.50	-.2
Electric Utilities																
Fossil Fuel Average	**1.87**	**1.78**	**1.66**	**1.52**	**1.66**	**1.71**	**1.76**	**1.83**	**1.89**	**1.94**	**2.03**	**2.10**	**2.16**	**2.22**	**2.29**	**2.7**
Petroleum Products	2.63	3.15	2.51	2.07	2.33	2.52	2.67	2.91	3.06	3.17	3.35	3.51	3.64	3.78	3.96	3.9
Distillate Fuel	4.20	4.12	3.96	3.43	3.94	4.18	4.42	4.67	4.88	5.07	5.36	5.60	5.81	6.04	6.31	4.0
Residual Fuel	2.53	3.07	2.38	1.96	2.27	2.46	2.60	2.81	2.95	3.07	3.24	3.38	3.49	3.62	3.79	4.0
Natural Gas	2.44	2.32	2.18	1.97	2.07	2.15	2.34	2.54	2.69	2.80	3.00	3.19	3.34	3.48	3.64	4.3
Steam Coal	1.69	1.56	1.50	1.40	1.53	1.54	1.55	1.57	1.58	1.59	1.60	1.62	1.63	1.64	1.65	.8
Hydroelectric Power	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.0
Nuclear Power	.80	.80	.78	.76	.73	.70	.67	.65	.63	.62	.60	.59	.59	.58	.57	-2.5
Average Price to All Users																
Petroleum Products	5.77	5.95	5.48	4.90	5.04	5.25	5.44	5.75	5.96	6.15	6.35	6.56	6.73	6.93	7.20	2.3
Distillate Fuel	5.58	5.72	5.46	4.94	5.53	5.78	6.02	6.27	6.47	6.63	6.93	7.16	7.37	7.60	7.86	3.1
Jet Fuel	4.20	4.19	3.81	3.35	3.40	3.61	3.81	4.09	4.29	4.47	4.69	4.89	5.06	5.25	5.51	3.1
Liquefied Petroleum Gas	6.92	6.22	4.87	4.56	4.41	4.75	5.09	5.50	5.80	6.07	6.34	6.60	6.87	7.16	7.51	3.7
Motor Gasoline	7.30	7.45	6.98	6.20	6.46	6.73	6.97	7.36	7.64	7.91	8.16	8.44	8.66	8.90	9.24	2.4
Residual Fuel	2.35	2.84	2.32	1.86	2.03	2.24	2.39	2.60	2.74	2.88	3.06	3.20	3.32	3.44	3.60	3.7
Other Petroleum Products	4.33	4.70	4.32	3.88	3.43	3.58	3.70	3.97	4.12	4.25	4.32	4.44	4.51	4.59	4.76	.8
Natural Gas	4.17	3.75	3.65	3.57	3.63	3.70	3.87	4.02	4.18	4.24	4.46	4.58	4.74	4.95	5.08	2.8
Coal [4]	1.72	1.58	1.52	1.44	1.55	1.55	1.57	1.58	1.59	1.61	1.62	1.63	1.64	1.65	1.67	.8
Electricity	20.05	19.15	19.04	18.78	19.14	19.03	18.89	18.58	18.47	18.32	18.23	18.25	18.33	18.39	18.50	-.2

[1] Includes liquefied petroleum gas and motor gasoline.
[2] Includes petrochemical feedstocks, still gas, lubricants, waxes, asphalt, special naphthas, and petroleum coke.
[3] Includes liquefied petroleum gas, lubricants, and waxes.
[4] Includes steam coal and metallurgical coal.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B4. Supply and Disposition of Electricity
(Quadrillion Btu)

Fuel Consumption and Disposition	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electric Utilities																
Fuel Inputs																
Oil																
Distillate	0.08	0.09	0.11	0.09	0.05	0.06	0.09	0.11	0.13	0.12	0.15	0.18	0.20	0.21	0.22	5.9
Residual	1.37	1.17	1.21	1.07	1.40	1.73	1.94	2.02	2.15	2.32	2.66	2.80	2.89	2.95	2.93	7.7
Natural Gas	2.69	2.92	2.92	2.92	2.95	2.96	3.03	3.29	3.55	3.76	4.12	4.41	4.67	5.03	5.41	5.3
Steam Coal	14.45	15.19	15.84	16.06	16.19	16.33	16.85	17.29	17.67	18.08	18.29	18.66	18.98	19.29	19.58	1.8
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [1]	3.23	2.81	2.59	3.10	3.26	3.29	3.30	3.31	3.34	3.35	3.36	3.37	3.38	3.38	3.38	2.3
Total Fuel Inputs	**26.30**	**27.09**	**28.31**	**28.87**	**29.63**	**30.35**	**31.20**	**32.07**	**32.90**	**33.71**	**34.68**	**35.54**	**36.32**	**37.08**	**37.74**	**2.4**
Net Imports (fuel input equiv.)	.37	.48	.42	.43	.45	.51	.53	.55	.57	.59	.64	.66	.69	.72	.75	5.1
Total Electricity Inputs	**26.67**	**27.57**	**28.72**	**29.30**	**30.08**	**30.87**	**31.73**	**32.62**	**33.47**	**34.30**	**35.32**	**36.21**	**37.01**	**37.80**	**38.49**	**2.5**
Disposition																
Total Electricity Inputs	26.67	27.57	28.72	29.30	30.08	30.87	31.73	32.62	33.47	34.30	35.32	36.21	37.01	37.80	38.49	2.5
Minus Conversion Losses	18.18	18.79	19.56	19.96	20.53	21.06	21.65	22.26	22.84	23.41	24.10	24.70	25.22	25.72	26.16	2.5
Generation	**8.49**	**8.78**	**9.16**	**9.34**	**9.55**	**9.81**	**10.08**	**10.36**	**10.63**	**10.89**	**11.21**	**11.51**	**11.79**	**12.07**	**12.33**	**2.5**
Plus Nonutility Purchases	.13	.16	.19	.25	.29	.31	.32	.34	.36	.38	.40	.41	.43	.45	.47	7.7
Plus Net Imports (electricity equiv.)	.12	.16	.14	.14	.15	.17	.18	.18	.19	.19	.21	.22	.23	.24	.25	5.1
Minus Trans. & Dist. Losses	.72	.72	.77	.80	.79	.82	.84	.87	.90	.92	.95	.98	1.01	1.03	1.06	2.8
Electricity Sales	**8.02**	**8.38**	**8.72**	**8.94**	**9.19**	**9.46**	**9.74**	**10.02**	**10.28**	**10.54**	**10.87**	**11.16**	**11.44**	**11.73**	**11.99**	**2.7**
Electricity Sales by End-Use Sector																
Residential	2.79	2.90	3.01	3.04	3.11	3.17	3.24	3.33	3.40	3.47	3.54	3.60	3.66	3.73	3.79	1.9
Commercial/Other [2]	2.47	2.60	2.70	2.82	2.90	2.98	3.06	3.16	3.24	3.33	3.42	3.50	3.58	3.66	3.74	2.7
Industrial	2.76	2.88	3.00	3.08	3.19	3.31	3.43	3.53	3.64	3.74	3.91	4.06	4.20	4.33	4.46	3.3
Total Electricity Sales	**8.02**	**8.38**	**8.72**	**8.94**	**9.19**	**9.46**	**9.74**	**10.02**	**10.28**	**10.54**	**10.87**	**11.16**	**11.44**	**11.73**	**11.99**	**2.7**
Nonutilities																
Fuel Inputs for Generation [3]																
Oil	.01	.01	.01	.01	.02	.02	.02	.02	.02	.02	.03	.03	.03	.03	.03	9.7
Gas	.26	.30	.35	.42	.48	.51	.54	.57	.60	.63	.66	.69	.73	.77	.81	7.3
Coal	.15	.17	.19	.22	.25	.26	.28	.30	.31	.33	.35	.37	.39	.42	.44	7.3
Nonfossil [4]	.33	.35	.38	.41	.44	.46	.49	.51	.53	.56	.58	.61	.64	.67	.70	5.4
Disposition of Generated Electricity																
Sales to Utilities	.13	.16	.19	.25	.29	.31	.32	.34	.36	.38	.40	.41	.43	.45	.47	7.7
Own Use	.25	.27	.28	.30	.32	.34	.36	.38	.40	.42	.44	.46	.49	.52	.55	5.8

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Includes street lighting and sales to the transportation sector.
[3] Represents energy content of fuel required for generation.
[4] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 636; File Creation Date 12/20/88.

Table B5. Electric Utility Summer Capability and Generation
(Capability in Million Kilowatts)
(Generation in Billion Kilowatthours)

Capability and Generation	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Net Capability [1]																
Coal Steam	291.7	292.8	294.6	296.8	296.9	297.9	299.0	299.1	299.8	301.7	305.5	310.1	313.6	317.6	322.4	0.8
Other Fossil Steam	146.4	145.3	144.7	144.5	144.4	141.0	140.6	139.5	136.5	134.5	133.0	131.6	130.5	129.4	127.9	-1.0
Combined Cycle	5.1	5.1	5.1	5.2	5.3	5.3	6.0	6.8	6.9	7.3	13.7	22.2	30.3	40.6	51.4	21.2
Turbine/Diesel	44.3	44.3	45.0	45.6	45.4	48.6	49.8	51.0	52.1	53.4	54.9	57.2	59.6	61.7	64.1	3.0
Nuclear Power	85.4	93.6	95.1	98.7	99.8	103.0	103.0	103.0	103.0	103.0	103.0	103.0	104.1	104.1	104.0	.7
Hydropower/Other [2]	93.4	93.7	94.3	94.4	95.3	96.0	97.0	97.6	98.4	98.6	98.9	98.9	99.0	99.1	99.2	.4
Total Capability	**666.3**	**674.8**	**678.7**	**685.2**	**687.1**	**691.8**	**695.3**	**696.9**	**696.8**	**698.6**	**708.9**	**723.0**	**737.1**	**752.4**	**768.9**	**1.0**
Generation by Plant Type																
Coal Steam	1,386	1,464	1,523	1,548	1,566	1,573	1,626	1,670	1,709	1,750	1,771	1,809	1,842	1,875	1,905	1.9
Other Fossil Steam	363	366	372	354	382	406	424	448	474	501	534	528	528	527	520	2.8
Combined Cycle	14	17	17	16	22	22	25	29	29	31	60	99	136	183	233	24.6
Turbine/Diesel	8	9	9	9	7	12	17	23	31	35	44	57	60	63	66	17.9
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [2]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,816**	**2,875**	**2,954**	**3,037**	**3,115**	**3,192**	**3,287**	**3,374**	**3,456**	**3,539**	**3,614**	**2.5**
Generation by Fuel Type																
Coal	1,386	1,464	1,523	1,548	1,566	1,573	1,626	1,670	1,709	1,750	1,771	1,809	1,842	1,875	1,905	1.9
Natural Gas	249	273	272	271	277	275	281	304	326	343	381	413	444	486	532	5.7
Oil	137	118	126	109	134	165	186	195	208	223	257	272	281	287	286	7.1
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [3]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,816**	**2,875**	**2,954**	**3,037**	**3,115**	**3,192**	**3,287**	**3,374**	**3,456**	**3,539**	**3,614**	**2.5**
Nonutilities																
Generation by Fuel Type [4]																
Residual Oil	1	1	2	2	2	3	3	3	3	4	4	4	4	5	5	9.7
Natural Gas	42	48	56	68	77	81	86	90	95	101	106	111	117	123	129	7.3
Steam Coal	21	24	27	32	35	37	40	42	44	47	50	53	56	59	62	7.3
Nonfossil [5]	48	51	55	61	65	68	71	74	78	82	85	89	94	98	103	5.4
Generation by Use																
Sales to Utilities	37	47	57	73	85	90	94	100	105	111	116	121	126	132	138	7.7
Own Use	75	78	82	89	95	100	105	110	116	122	129	136	144	152	161	5.8

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2] Includes other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[3] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[4] Individual fuel inputs converted to Kilowatthours based on average heat rate for each respective fuel.
[5] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	Low World Oil Price Case														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Additions															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	5,281	6,240	4,538	5,062	5,770	40,957
Combined Cycle [2]	0	14	20	153	0	681	767	164	408	6,336	8,483	8,168	10,264	10,783	46,242
Turbines [3]	263	709	589	58	3,263	1,238	1,252	1,262	1,362	1,558	2,377	2,359	2,091	2,512	20,632
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total New Capability	**10,930**	**5,504**	**6,817**	**2,960**	**10,218**	**4,100**	**3,028**	**3,734**	**5,283**	**13,410**	**17,142**	**16,267**	**17,519**	**19,168**	**125,151**
Announced/Planned Construction [4]															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	2,382	2,188	672	142	602	20,052
Combined Cycle [2]	0	14	20	153	0	681	767	164	102	288	28	102	0	0	2,319
Turbines [3]	263	709	589	58	153	58	66	90	64	225	286	434	278	77	3,087
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total Planned	**10,930**	**5,504**	**6,817**	**2,960**	**7,108**	**2,920**	**1,842**	**2,562**	**3,679**	**3,130**	**2,544**	**2,410**	**522**	**781**	**42,779**
Additional Needed Capability [5]															
Nuclear Power [1]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	2,899	4,052	3,866	4,920	5,168	20,905
Combined Cycle [2]	0	0	0	0	0	0	0	0	306	6,048	8,455	8,066	10,264	10,783	43,923
Turbines [3]	0	0	0	0	3,110	1,180	1,186	1,172	1,298	1,333	2,091	1,925	1,813	2,435	17,545
Total Additional Needed	**0**	**0**	**0**	**0**	**3,110**	**1,180**	**1,186**	**1,172**	**1,604**	**10,280**	**14,598**	**13,857**	**16,997**	**18,387**	**82,372**

[1] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes all new capability announced by the electric utility industry.
[5] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B7. Electric Utility Sales, Prices, and Price Components
(Billion Kilowatthours)
(1988 Dollars per Thousand Kilowatthours)

Sales, Prices, and Price Component	Low World Oil Price Case														Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electricity Sales by End-Use Sector																
Residential	818	850	884	890	910	930	951	975	995	1,017	1,037	1,056	1,073	1,093	1,109	1.9
Commercial/Other [1]	725	761	792	827	850	873	898	925	950	976	1,002	1,026	1,049	1,074	1,097	2.7
Industrial	808	845	881	903	934	971	1,005	1,036	1,067	1,097	1,146	1,190	1,232	1,270	1,307	3.3
Total Electricity Sales	**2,351**	**2,456**	**2,556**	**2,620**	**2,694**	**2,774**	**2,853**	**2,935**	**3,012**	**3,090**	**3,185**	**3,272**	**3,354**	**3,437**	**3,514**	**2.7**
Prices [2]																
Residential	78.53	76.45	75.80	71.84	76.14	75.83	75.41	74.36	74.04	73.54	73.36	73.51	73.89	74.06	74.57	-.1
Commercial/Other [1]	75.54	71.84	71.56	72.25	71.97	71.66	71.27	70.23	69.93	69.45	69.28	69.44	69.83	70.07	70.54	-.1
Industrial	51.83	48.31	48.13	48.92	48.66	48.40	47.99	46.94	46.62	46.13	45.93	46.08	46.47	46.83	47.21	-.2
All Sectors	**68.43**	**65.33**	**64.95**	**64.07**	**65.30**	**64.92**	**64.45**	**63.38**	**63.03**	**62.52**	**62.21**	**62.26**	**62.55**	**62.75**	**63.13**	**-.2**
Price Components																
Capital Component [3]	32.48	30.92	30.20	31.52	31.18	30.76	29.95	28.47	27.74	26.88	25.91	25.37	25.25	24.99	24.84	-1.6
Fuel Component [4]	16.98	16.68	15.88	15.23	15.28	15.47	15.96	16.55	17.06	17.51	18.32	18.98	19.48	20.01	20.60	2.2
O&M Component [5]	18.97	19.08	18.86	18.89	18.84	18.68	18.54	18.36	18.23	18.13	17.99	17.91	17.83	17.75	17.70	-.5
Total Price [2]	**68.43**	**66.68**	**64.94**	**65.65**	**65.30**	**64.92**	**64.45**	**63.38**	**63.03**	**62.52**	**62.21**	**62.26**	**62.55**	**62.75**	**63.14**	**-.2**

[1] Includes consumption for street and highway lighting, other public authorities, and railways.
[2] Prices for 1988 to 2000 are estimated from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry.
[3] Represents the cost to the utility of capital assets needed to promote reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[4] Includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[5] 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.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 636; File Creation Date 12/20/88.

Table B8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1] (1988 dollars per barrel)	14.92	18.70	14.70	12.40	12.89	13.40	13.80	14.80	15.80	16.70	17.70	18.70	19.50	20.40	21.70	3.3
Production																
Crude Oil [2]	8.68	8.35	8.18	7.80	7.54	7.08	6.64	6.32	6.05	5.79	5.60	5.43	5.31	5.21	5.15	-3.8
Alaska	1.87	1.96	2.03	2.00	1.93	1.74	1.54	1.41	1.31	1.18	1.09	.99	.92	.86	.81	-7.4
Lower 48	6.81	6.39	6.15	5.80	5.61	5.34	5.11	4.91	4.74	4.61	4.51	4.44	4.38	4.35	4.35	-2.9
Natural Gas Liquids	1.55	1.60	1.61	1.62	1.68	1.74	1.74	1.76	1.77	1.79	1.81	1.84	1.85	1.87	1.90	1.4
Other Domestic	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.6
Processing Gain [3]	.62	.64	.66	.66	.67	.66	.66	.65	.65	.64	.64	.64	.65	.65	.65	-.1
Total Production	10.90	10.65	10.51	10.14	9.95	9.55	9.10	8.79	8.53	8.29	8.12	7.97	7.87	7.80	7.77	-2.5
Imports (Including SPR [4])																
Crude Oil	4.18	4.67	5.12	5.85	6.52	7.03	7.61	7.91	8.25	8.56	8.95	9.19	9.47	9.72	9.86	5.6
Refined Products	2.05	2.00	1.96	2.11	2.21	2.31	2.39	2.44	2.49	2.54	2.62	2.67	2.71	2.75	2.76	2.9
Total Imports	6.22	6.67	7.08	7.96	8.73	9.34	10.00	10.35	10.74	11.11	11.57	11.87	12.19	12.47	12.62	4.9
Exports																
Crude Oil	.15	.15	.17	.17	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	1.3
Refined Products	.63	.61	.64	.62	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.0
Total Exports	.78	.76	.80	.79	.83	.83	.83	.83	.83	.83	.83	.83	.83	.83	.83	.2
Net Imports	5.44	5.91	6.28	7.17	7.90	8.51	9.17	9.52	9.92	10.28	10.75	11.04	11.36	11.65	11.79	5.4
Primary Stock Changes [5]																
Net Withdrawals	-.15	.04	.04	.01	-.07	.00	-.03	-.01	-.02	-.02	-.05	-.03	-.04	-.04	-.02	
SPR [4] Fill Rate (-)	-.05	-.08	-.05	-.05	-.08	-.08	-.08	-.08	-.08	-.08	-.03	.00	.00	.00	.00	
Total Primary Supply [6]	16.14	16.52	16.78	17.27	17.71	17.99	18.17	18.23	18.35	18.48	18.78	18.98	19.19	19.40	19.54	1.3
Refined Petroleum Products																
Motor Gasoline	7.03	7.21	7.34	7.50	7.57	7.52	7.48	7.44	7.43	7.41	7.44	7.47	7.51	7.56	7.59	.3
Jet Fuel [7]	1.31	1.37	1.44	1.50	1.53	1.56	1.59	1.61	1.63	1.64	1.67	1.69	1.71	1.74	1.76	1.7
Distillate Fuel [8]	3.01	3.07	3.22	3.34	3.36	3.42	3.48	3.51	3.54	3.55	3.60	3.65	3.69	3.73	3.76	1.3
Residual Fuel	1.42	1.26	1.25	1.24	1.38	1.53	1.62	1.65	1.70	1.76	1.91	1.97	2.00	2.03	2.01	4.1
Other Petroleum Products [9]	3.52	3.76	3.76	3.80	3.92	3.96	4.00	4.03	4.06	4.10	4.16	4.21	4.27	4.34	4.40	1.3
Total Product Supplied	16.29	16.67	17.01	17.39	17.76	17.98	18.17	18.23	18.35	18.47	18.78	18.98	19.19	19.40	19.53	1.2
Refined Petroleum Products Supplied by Sector																
Residential/Commercial	1.35	1.37	1.41	1.46	1.44	1.44	1.43	1.41	1.40	1.39	1.38	1.36	1.36	1.35	1.34	-.4
Industrial	4.09	4.30	4.30	4.42	4.51	4.56	4.61	4.62	4.66	4.70	4.76	4.82	4.89	4.96	5.02	1.3
Transportation	10.22	10.46	10.73	11.01	11.17	11.21	11.25	11.26	11.29	11.32	11.41	11.49	11.59	11.71	11.80	.8
Electric Utilities	.63	.55	.58	.51	.63	.78	.88	.93	1.00	1.07	1.23	1.30	1.35	1.38	1.37	7.5
Total Consumption	16.29	16.67	17.01	17.39	17.76	17.98	18.17	18.23	18.35	18.47	18.78	18.98	19.19	19.40	19.53	1.2
Discrepancy [10]	-.15	-.15	-.23	-.12	-.05	.00	.00	.00	.01	.01	.01	.01	.01	.01	.01	
Net Disposition [11]	16.14	16.52	16.78	17.27	17.71	17.99	18.17	18.23	18.35	18.48	18.78	18.98	19.19	19.40	19.54	1.3

[1] Represents the cost of imported crude oil to U.S. refiners.
[2] Includes lease condensate.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] SPR is the Strategic Petroleum Reserve.
[5] A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[6] Equals total production plus net imports plus net stock withdrawals minus SPR fill rate.
[7] Includes naphtha and kerosene type.
[8] Includes kerosene.
[9] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, plant condensate, pentanes plus, asphalt and road oil, still gas, special naphthas, petroleum coke, unfinished oils, and miscellaneous petroleum products.
[10] Represents the difference between total primary supply and total consumption.
[11] Represents the sum of total consumption and discrepancy.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B9. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet)
(1988 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Dry Gas Production	15.99	16.54	16.71	16.71	17.17	17.21	17.22	17.40	17.53	17.70	17.96	18.20	18.35	18.54	18.82	1.0
Supplemental Gas [1]	.11	.10	.17	.18	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	-4.3
Net Imports	**.69**	**.94**	**1.15**	**1.32**	**1.44**	**1.50**	**1.59**	**1.68**	**1.77**	**1.84**	**1.93**	**2.00**	**2.10**	**2.18**	**2.27**	**5.8**
Net Storage Withdrawals [2]	**-.15**	**.00**	**.04**	**.05**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	
Total Supply [3]	**16.65**	**17.57**	**18.07**	**18.26**	**18.71**	**18.81**	**18.91**	**19.17**	**19.40**	**19.64**	**19.99**	**20.30**	**20.55**	**20.82**	**21.18**	**1.3**
Consumption by Sector																
Residential	4.30	4.32	4.59	4.66	4.64	4.66	4.63	4.60	4.57	4.57	4.51	4.49	4.46	4.41	4.39	-.4
Commercial [4]	2.31	2.41	2.61	2.65	2.67	2.71	2.71	2.72	2.72	2.75	2.74	2.75	2.76	2.75	2.76	.5
Industrial	5.60	5.89	6.15	6.24	6.45	6.49	6.54	6.54	6.52	6.51	6.54	6.54	6.53	6.49	6.46	.4
Lease & Plant Fuel [5]	.92	1.15	1.01	1.03	1.04	1.02	1.03	1.04	1.05	1.06	1.07	1.09	1.10	1.11	1.12	.9
Transportation [6]	.48	.52	.55	.54	.51	.50	.51	.52	.53	.54	.55	.56	.56	.57	.58	.4
Electric Utilities	2.61	2.84	2.83	2.83	2.86	2.87	2.94	3.19	3.44	3.65	4.00	4.28	4.53	4.88	5.25	5.3
Total Consumption	**16.23**	**17.13**	**17.75**	**17.95**	**18.16**	**18.26**	**18.36**	**18.61**	**18.84**	**19.07**	**19.41**	**19.71**	**19.95**	**20.21**	**20.57**	**1.2**
Unaccounted for [7]	**.41**	**.45**	**.32**	**.31**	**.54**	**.55**	**.55**	**.56**	**.57**	**.57**	**.58**	**.59**	**.60**	**.61**	**.62**	
Average Wellhead Price	**2.06**	**1.72**	**1.62**	**1.64**	**1.69**	**1.73**	**1.99**	**2.23**	**2.40**	**2.49**	**2.79**	**2.90**	**3.14**	**3.34**	**3.52**	**6.7**
Average Price by Sector																
Residential	6.21	5.74	5.50	5.29	5.45	5.60	5.78	5.97	6.17	6.24	6.51	6.66	6.85	7.14	7.31	2.4
Commercial [4]	5.43	4.93	4.75	4.73	4.77	4.81	4.99	5.17	5.37	5.43	5.70	5.85	6.03	6.32	6.47	2.6
Industrial	3.35	2.93	2.87	2.90	2.93	2.96	3.14	3.31	3.51	3.57	3.84	3.98	4.16	4.45	4.60	4.0
Electric Utilities	2.52	2.39	2.25	2.03	2.13	2.22	2.41	2.62	2.77	2.89	3.09	3.29	3.44	3.59	3.75	4.3
Average to All Sectors [8]	**4.36**	**3.93**	**3.81**	**3.72**	**3.79**	**3.87**	**4.04**	**4.19**	**4.36**	**4.42**	**4.64**	**4.77**	**4.92**	**5.14**	**5.27**	**2.7**

[1] Includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane-air mixtures.
[2] Includes net withdrawals of dry natural gas from underground storage and liquefied natural gas. A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[3] Total supply represents the sum of dry gas production, supplemental gas, net imports, and net storage withdrawals.
[4] Includes deliveries to municipalities and other public authorities for use in schools and other institutions.
[5] Represents natural gas used in gathering systems and processing plants.
[6] Represents natural gas used to fuel compressors in pipeline pumping stations.
[7] Represents the difference between total supply and total consumption.
[8] Weighted average price. The weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding. Commercial and industrial natural gas prices for 1989, reflect base case values from PC-AEO Model run 635.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B10. Coal Supply, Disposition, and Prices
(Million Short Tons)
(1988 Dollars per Short Ton)

Supply, Disposition, and Prices	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Production [1]	890	919	941	946	976	990	1,019	1,041	1,060	1,082	1,094	1,119	1,138	1,157	1,175	1.9
Imports	2	2	2	2	3	4	4	4	5	5	5	5	6	6	7	10.1
Exports [2]	86	80	86	82	85	87	89	91	93	95	98	102	105	109	112	2.3
Net Imports	-83	-78	-84	-80	-82	-83	-85	-87	-88	-90	-93	-97	-99	-103	-105	1.9
Net Storage Withdrawals [3]	-4	-6	17	17	-2	-5	-7	-6	-5	-6	-3	-5	-4	-4	-4	
Total Supply [4]	803	834	875	882	893	902	928	948	967	987	998	1,017	1,035	1,050	1,065	1.7
Consumption by Sector																
Residential/Commercial	8	7	7	7	7	7	7	7	7	7	7	7	7	7	7	-.9
Industrial	76	75	75	75	76	77	77	77	78	78	79	80	81	81	82	.7
Coking Plants	36	37	39	39	39	39	39	39	38	38	38	38	37	37	37	-.5
Electric Utilities	685	718	750	760	771	779	804	825	844	865	875	894	910	925	940	1.9
Total Consumption	804	837	872	882	893	902	928	948	967	987	998	1,017	1,035	1,050	1,065	1.7
Discrepancy [5]	-1	-3	3	0	0	0	0	0	0	0	0	0	0	0	0	
Average Minemouth Price [6]	25.36	23.79	23.61	23.26	23.76	23.86	24.07	24.28	24.45	24.61	24.72	24.93	25.08	25.24	25.42	.6
Delivered Price by Sector																
Residential/Commercial	52.08	48.19	46.32	45.91	46.36	46.45	46.78	47.17	47.55	47.95	48.25	48.66	49.00	49.39	49.80	.6
Industrial	38.20	34.76	34.92	34.55	34.86	34.83	35.11	35.42	35.55	35.85	36.08	36.40	36.51	36.78	36.93	.5
Coking Plants	54.18	48.01	47.15	46.69	47.17	47.34	47.73	48.16	48.57	49.00	49.36	49.83	50.21	50.62	51.10	.7
Electric Utilities	35.49	32.95	31.74	29.79	32.12	32.20	32.49	32.80	33.04	33.30	33.48	33.75	33.92	34.13	34.40	.7
Average to All Sectors [7]	36.74	33.91	32.82	31.07	33.12	33.20	33.47	33.75	33.96	34.20	34.38	34.65	34.81	35.01	35.27	.7

[1] Includes anthracite, bituminous coal, and lignite.
[2] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces.
[3] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. A negative (-) result represents an increase to inventories. A positive result represents a withdrawal from inventories.
[4] Represents the sum of production, net imports, and net storage withdrawals.
[5] Represents the difference between total supply and total consumption.
[6] Free on board (F.O.B.) mines.
[7] Weighted average prices. The weights used are consumption values by sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); *Quarterly Coal Report*, DOE/EIA-0121(88/2Q); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Table B11. National Macroeconomic Indicators

Macroeconomic Indicators	Low World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1]																
1988 dollars per barrel	14.92	18.70	14.70	12.40	12.89	13.40	13.80	14.80	15.80	16.70	17.70	18.70	19.50	20.40	21.70	3.3
Nominal dollars per barrel	14.00	18.13	14.70	12.86	13.98	15.25	16.51	18.62	20.91	23.25	25.92	28.76	31.43	34.45	38.27	8.3
1982 dollars per barrel	12.29	15.40	12.11	10.21	10.62	11.04	11.37	12.19	13.01	13.76	14.58	15.40	16.06	16.80	17.87	3.3
Economic Variables																
Real GNP (billion 1982 dollars)	3,722	3,847	4,001	4,116	4,221	4,344	4,463	4,571	4,677	4,779	4,905	5,015	5,140	5,276	5,410	2.5
Real Disposable Income (billion 1982 dollars)	2,641	2,687	2,787	2,860	2,929	2,999	3,068	3,133	3,198	3,258	3,331	3,400	3,474	3,552	3,628	2.2
Real Disposable Income per Capita (thousand 1982 dollars)	10.9	11.0	11.3	11.5	11.7	11.9	12.1	12.2	12.4	12.5	12.7	12.9	13.1	13.3	13.5	1.5
GNP Implicit Price Deflator (1982=1.00)	1.139	1.177	1.214	1.259	1.317	1.382	1.452	1.527	1.607	1.690	1.778	1.867	1.957	2.050	2.141	4.8
Unemployment Rate (percent)	7.0	6.2	5.4	5.2	5.3	5.3	5.5	5.7	6.0	6.3	6.4	6.6	6.8	6.9	7.1	
Population, Noninstitutional (million persons)	241.3	243.5	245.6	247.8	250.0	252.1	254.2	256.2	258.1	259.9	261.7	263.5	264.6	266.8	268.4	.7
New AA Bond Rate (percent per annum)	8.94	9.50	10.26	11.19	10.36	10.35	10.16	9.78	9.83	9.80	9.83	9.80	9.72	9.61	9.45	
Energy Usage Indicators																
Gross Energy Use (quadrillion Btu)	74.3	76.8	79.4	81.0	82.5	83.5	84.6	85.5	86.4	87.3	88.6	89.7	90.9	91.9	92.9	1.3
Gross Energy Use per Capita (million Btu per person)	307.8	315.5	323.4	326.9	329.9	331.3	332.8	333.6	334.6	335.8	338.5	340.6	343.4	344.5	346.0	.6
Gross Energy Use per Dollar of GNP (thousand Btu per 1982 dollar)	20.0	20.0	19.9	19.7	19.5	19.2	19.0	18.7	18.5	18.3	18.1	17.9	17.7	17.4	17.2	-1.2
Gross Petroleum and Natural Gas Use per Dollar of GNP (thousand Btu per 1982 dollar)	13.3	13.1	12.9	12.8	12.7	12.5	12.3	12.1	11.9	11.8	11.7	11.5	11.4	11.2	11.1	-1.3
Energy/GNP Rate of Change (percent)																
1985-1990	-.9															
1985-1995	-1.1															
1985-2000	-1.2															
1990-1995	-1.3															
1995-2000	-1.2															
1988-2000	-1.2															

[1] Represents the cost of imported crude oil to U.S. refiners.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Data Resources, Inc., USMODEL database (October 1988); Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 636; File Creation Date 12/20/88.

Appendix C

High World Oil Price Forecasts

Appendix C

High World Oil Price Case Forecasts

Table C1. Yearly Supply and Disposition Summary of Total Energy (Quadrillion Btu)

Supply and Disposition	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Crude Oil	18.4	17.7	17.3	17.1	16.4	15.8	15.4	15.0	14.6	14.4	14.2	14.2	14.2	14.2	14.3	-1.6
Natural Gas Plant Liquids	2.1	2.2	2.2	2.2	2.3	2.3	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.6	1.2
Natural Gas [1]	16.5	17.0	17.2	17.2	17.4	17.2	17.4	17.5	17.6	17.8	18.1	18.3	18.6	18.7	18.9	.8
Coal	19.5	20.2	20.7	20.7	21.5	21.8	22.2	22.7	23.2	23.9	23.9	24.4	24.7	25.0	25.3	1.7
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [2]	3.3	2.8	2.6	3.1	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.4	3.4	3.4	3.4	2.2
Total Production	**64.3**	**64.9**	**65.7**	**66.0**	**66.6**	**66.5**	**66.6**	**67.0**	**67.3**	**67.9**	**68.1**	**68.8**	**69.5**	**70.1**	**70.7**	**.6**
Imports																
Crude Oil [3]	9.0	10.1	11.0	11.4	12.3	12.8	13.0	13.4	14.0	14.5	14.9	14.9	15.0	15.2	15.2	2.7
Petroleum Products	4.4	4.3	4.2	4.4	4.5	4.6	4.6	4.7	4.8	4.9	5.0	5.0	5.0	5.0	5.0	1.4
Natural Gas [4]	.7	.9	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	2.0	2.1	2.2	2.3	2.3	6.2
Other Imports [5]	.4	.5	.5	.5	.5	.6	.6	.7	.7	.7	.8	.8	.8	.9	.9	5.1
Total Imports	**14.5**	**15.8**	**16.9**	**17.7**	**18.8**	**19.5**	**19.9**	**20.4**	**21.3**	**22.0**	**22.6**	**22.8**	**23.0**	**23.3**	**23.5**	**2.8**
Exports																
Coal	2.2	2.1	2.3	2.2	2.3	2.4	2.5	2.6	2.7	2.8	2.8	2.9	2.9	2.9	2.9	2.2
Petroleum	1.7	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	.2
Total Exports	**3.9**	**3.7**	**4.0**	**3.8**	**4.0**	**4.1**	**4.2**	**4.3**	**4.4**	**4.5**	**4.6**	**4.6**	**4.6**	**4.6**	**4.7**	**1.4**
Adjustments [6]	**-.6**	**-.2**	**.8**	**.2**	**-.7**	**-.9**	**-.8**	**-.9**	**-1.0**	**-1.1**	**-.9**	**-.8**	**-.8**	**-.9**	**-.9**	
Consumption																
Petroleum Products [7]	32.2	32.9	33.7	33.5	33.6	33.5	33.4	33.4	33.7	34.0	34.5	34.7	34.7	34.9	35.1	.3
Natural Gas	16.7	17.6	18.3	18.5	18.4	18.3	18.6	18.8	19.0	19.2	19.7	19.9	20.3	20.5	20.8	1.1
Coal	17.3	18.0	18.8	18.9	19.1	19.3	19.6	20.0	20.4	20.9	21.1	21.4	21.7	22.0	22.3	1.4
Nuclear Power	4.5	4.9	5.6	5.6	5.8	6.0	6.0	6.0	6.1	6.1	6.1	6.1	6.2	6.2	6.2	.8
Hydropower/Other [8]	3.6	3.3	3.1	3.6	3.8	3.9	3.9	3.9	4.0	4.0	4.1	4.1	4.1	4.2	4.2	2.6
Total Consumption	**74.3**	**76.8**	**79.4**	**80.2**	**80.7**	**80.9**	**81.4**	**82.2**	**83.1**	**84.3**	**85.4**	**86.2**	**87.1**	**87.9**	**88.6**	**.9**
Net Imports - Petroleum	**11.7**	**12.8**	**13.6**	**14.2**	**15.0**	**15.6**	**15.9**	**16.3**	**17.0**	**17.6**	**18.1**	**18.2**	**18.2**	**18.4**	**18.4**	**2.6**
Prices (1988 dollars per unit)																
World Oil Price ($ per barrel)[9]	$14.92	$18.70	$14.70	$17.10	$18.00	$19.10	$20.20	$21.20	$22.80	$24.40	$26.50	$28.60	$30.80	$32.90	$35.00	7.5
Avg. Wellhead Price ($ per Mcf)	2.06	1.72	1.62	1.64	1.85	2.07	2.24	2.52	2.81	3.09	3.46	3.67	3.85	4.10	4.32	8.5
Avg. Coal Minemouth Price ($ per ton)	25.36	23.79	23.61	23.77	24.34	24.51	24.68	24.89	25.14	25.41	25.48	25.68	25.84	26.00	26.14	.9
Real GNP (billion 1982 dollars)	**3,722**	**3,847**	**4,001**	**4,116**	**4,211**	**4,300**	**4,387**	**4,483**	**4,597**	**4,730**	**4,859**	**4,963**	**5,078**	**5,207**	**5,335**	**2.4**

[1] Dry natural gas.
[2] Includes hydropower, geothermal power, wood, and waste.
[3] Includes imports of crude oil for the Strategic Petroleum Reserve.
[4] Represents net imports.
[5] Includes coal, net coal coke imports, and net electricity imports.
[6] Balancing item. Includes stock changes, unaccounted for supply, losses, and gains.
[7] Includes natural gas plant liquids and crude oil consumed as fuels.
[8] Includes industrial generation of hydroelectric power, net electricity imports, and electricity produced from geothermal, wood, waste, wind, photovoltaic, and solar thermal sources connected to electric utility distribution systems. Also includes net coal coke imports.
[9] Represents the cost of imported crude oil to U.S. refiners.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecast: Based on Run 637; File Creation Date 12/20/88.

Table C2. Consumption of Energy by Source and End-Use Sector
(Quadrillion Btu)

Sector and Fuel	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential																
Distillate [1]	1.10	1.10	1.16	1.17	1.13	1.11	1.08	1.05	1.03	1.00	0.98	0.95	0.93	0.91	0.89	-2.2
Liquefied Petroleum Gas	.41	.44	.45	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	.44	-.1
Natural Gas	4.43	4.45	4.73	4.80	4.75	4.71	4.70	4.66	4.61	4.56	4.50	4.46	4.44	4.39	4.36	-.7
Coal	.07	.06	.07	.07	.06	.06	.06	.06	.06	.06	.06	.06	.06	.05	.05	-1.9
Electricity	2.79	2.90	3.01	3.03	3.10	3.16	3.22	3.30	3.37	3.43	3.49	3.55	3.60	3.66	3.71	1.8
Total	**8.80**	**8.96**	**9.41**	**9.50**	**9.50**	**9.48**	**9.51**	**9.53**	**9.50**	**9.50**	**9.47**	**9.46**	**9.47**	**9.46**	**9.46**	**.0**
Commercial																
Distillate [1]	.64	.64	.67	.67	.70	.70	.70	.70	.70	.70	.70	.70	.71	.71	.71	.5
Motor Gasoline	.11	.11	.11	.11	.11	.12	.12	.12	.12	.13	.13	.13	.14	.14	.14	2.2
Residual Fuel	.25	.23	.22	.21	.21	.20	.19	.18	.17	.16	.15	.13	.12	.12	.11	-5.7
Natural Gas	2.38	2.48	2.69	2.73	2.72	2.71	2.74	2.73	2.71	2.70	2.68	2.68	2.71	2.69	2.70	.1
Other Commercial [2]	.17	.18	.18	.18	.18	.17	.17	.17	.17	.17	.17	.17	.17	.17	.17	-.4
Electricity	2.46	2.58	2.69	2.80	2.88	2.95	3.03	3.13	3.21	3.29	3.37	3.44	3.52	3.60	3.67	2.6
Total	**6.01**	**6.22**	**6.55**	**6.70**	**6.80**	**6.85**	**6.95**	**7.03**	**7.08**	**7.15**	**7.20**	**7.27**	**7.36**	**7.43**	**7.51**	**1.1**
Industrial																
Distillate [1]	1.28	1.32	1.38	1.41	1.40	1.42	1.43	1.44	1.46	1.49	1.51	1.53	1.55	1.57	1.59	1.1
Liquefied Petroleum Gas	1.48	1.58	1.60	1.59	1.63	1.67	1.70	1.74	1.78	1.83	1.87	1.92	1.96	2.01	2.05	2.1
Motor Gasoline	.21	.21	.22	.22	.22	.22	.22	.23	.23	.24	.24	.24	.25	.25	.25	1.4
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	.83	.76	.74	.68	.70	.68	.65	.63	.62	.60	.58	.56	.54	.52	.51	-3.1
Natural Gas [3]	6.72	7.25	7.38	7.49	7.45	7.42	7.38	7.36	7.35	7.37	7.35	7.31	7.28	7.22	7.16	-.2
Metallurgical Coal	.96	.99	1.08	1.04	1.03	1.01	.98	.97	.96	.97	.97	.96	.95	.94	.93	-1.3
Steam Coal	1.67	1.69	1.69	1.67	1.67	1.65	1.65	1.66	1.67	1.70	1.73	1.76	1.78	1.80	1.83	.7
Other Industrial [4]	3.18	3.57	3.72	3.45	3.43	3.41	3.36	3.34	3.33	3.35	3.35	3.34	3.34	3.35	3.36	-.8
Hydropower	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.3
Electricity	2.76	2.88	3.00	3.09	3.16	3.22	3.29	3.40	3.53	3.69	3.85	3.98	4.11	4.23	4.35	3.1
Total	**20.06**	**21.19**	**21.66**	**21.53**	**21.60**	**21.62**	**21.63**	**21.74**	**21.94**	**22.25**	**22.51**	**22.69**	**22.86**	**23.02**	**23.18**	**.6**
Transportation																
Distillate [1]	3.30	3.37	3.52	3.64	3.74	3.80	3.87	3.90	3.96	4.03	4.09	4.15	4.20	4.25	4.30	1.7
Jet Fuel	2.68	2.82	2.96	3.03	3.07	3.09	3.11	3.13	3.17	3.22	3.27	3.28	3.30	3.34	3.37	1.1
Motor Gasoline	13.17	13.50	13.75	13.83	13.69	13.44	13.22	13.09	13.02	13.01	13.00	12.95	12.93	12.93	12.33	-.5
Residual Fuel	.82	.74	.71	.73	.74	.75	.76	.78	.80	.81	.83	.85	.87	.89	.90	2.0
Natural Gas	.50	.53	.57	.56	.52	.50	.50	.51	.52	.52	.53	.54	.55	.55	.56	-.1
Other Transportation [5]	.27	.28	.30	.30	.31	.31	.32	.32	.33	.33	.34	.35	.35	.36	.36	1.5
Total	**20.75**	**21.24**	**21.82**	**22.08**	**22.06**	**21.90**	**21.78**	**21.74**	**21.79**	**21.93**	**22.06**	**22.12**	**22.19**	**22.31**	**22.42**	**.2**
Electric Utilities																
Distillate	.08	.09	.11	.09	.05	.06	.08	.11	.13	.12	.16	.19	.19	.20	.21	5.4
Residual Fuel	1.37	1.17	1.21	1.07	1.11	1.15	1.16	1.25	1.37	1.55	1.78	1.86	1.77	1.82	1.81	3.4
Natural Gas	2.69	2.92	2.92	2.92	2.95	2.97	3.28	3.54	3.82	4.09	4.61	4.95	5.36	5.68	6.02	6.2
Steam Coal	14.45	15.19	15.84	16.06	16.26	16.46	16.79	17.21	17.63	18.12	18.22	18.54	18.82	19.14	19.40	1.7
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [6]	3.60	3.29	3.00	3.53	3.71	3.80	3.83	3.87	3.91	3.94	4.00	4.03	4.07	4.10	4.13	2.7
Total	**26.67**	**27.57**	**28.72**	**29.30**	**29.86**	**30.42**	**31.13**	**32.01**	**32.91**	**33.90**	**34.87**	**35.69**	**36.42**	**37.15**	**37.79**	**2.3**
Primary Energy Consumption																
Distillate [1]	6.40	6.52	6.84	6.97	7.02	7.09	7.16	7.21	7.28	7.35	7.44	7.52	7.58	7.63	7.69	1.0
Jet Fuel	2.68	2.82	2.96	3.03	3.07	3.09	3.11	3.13	3.17	3.22	3.27	3.28	3.30	3.34	3.37	1.1
Liquefied Petroleum Gas	2.01	2.15	2.18	2.16	2.20	2.24	2.27	2.31	2.36	2.40	2.45	2.49	2.54	2.58	2.63	1.6
Motor Gasoline	13.49	13.82	14.08	14.16	14.02	13.78	13.56	13.44	13.38	13.37	13.37	13.33	13.31	13.32	13.33	-.5
Petrochemical Feedstocks	.95	.90	.81	.85	.88	.90	.92	.94	.97	.99	1.01	1.04	1.06	1.09	1.12	2.7
Residual Fuel	3.26	2.89	2.87	2.68	2.75	2.78	2.76	2.84	2.96	3.13	3.35	3.41	3.31	3.34	3.33	1.2
Natural Gas	16.72	17.64	18.28	18.49	18.38	18.31	18.60	18.80	19.00	19.24	19.67	19.94	20.33	20.53	20.81	1.1
Metallurgical Coal	.96	.99	1.08	1.04	1.03	1.01	.98	.97	.96	.97	.97	.96	.95	.94	.93	-1.3
Steam Coal	16.30	17.04	17.70	17.90	18.10	18.27	18.60	19.02	19.46	19.98	20.11	20.45	20.76	21.09	21.37	1.6
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Net Coal Coke Imports	-.02	.01	.05	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	.03	-4.8
Hydropower/Misc. [7]	7.02	7.11	7.00	7.25	7.41	7.49	7.47	7.49	7.53	7.58	7.65	7.68	7.71	7.76	7.81	.9
Total Consumption	**74.27**	**76.81**	**79.45**	**80.18**	**80.65**	**80.94**	**81.43**	**82.20**	**83.11**	**84.31**	**85.37**	**86.23**	**87.05**	**87.85**	**88.61**	**.9**
Electricity (all sectors)	**8.02**	**8.38**	**8.72**	**8.93**	**9.15**	**9.34**	**9.56**	**9.84**	**10.12**	**10.43**	**10.72**	**10.99**	**11.25**	**11.51**	**11.75**	**2.5**

[1] Includes kerosene.
[2] Includes liquefied petroleum gas and coal.
[3] Includes lease and plant fuel.
[4] Includes still gas, lubricants, waxes, asphalt, special naphthas, petroleum coke, and net coal coke imports.
[5] Includes electricity, liquefied petroleum gas, lubricants, and waxes.
[6] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports.
[7] Includes hydropower and electricity that is produced by renewable sources such as geothermal power, wood, waste, solar power, and wind power. Also includes net electricity imports and minor petroleum products.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C3. Price of Energy by Source and End-Use Sector
(1988 Dollars per Million Btu)

Sector and Fuel	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Residential	**11.57**	**11.17**	**10.83**	**11.01**	**11.26**	**11.54**	**11.69**	**11.88**	**12.20**	**12.50**	**12.86**	**13.19**	**13.45**	**13.83**	**14.15**	**2.3**
Primary Energy	6.27	5.80	5.47	5.64	5.86	6.05	6.20	6.44	6.76	7.05	7.42	7.71	7.90	8.27	8.53	3.8
Petroleum Products	7.10	6.59	5.96	6.23	6.68	7.05	7.36	7.70	8.09	8.50	8.99	9.46	9.91	10.42	10.90	5.2
Distillate Fuel	6.40	5.97	5.80	5.98	6.31	6.56	6.80	7.07	7.39	7.74	8.18	8.57	8.94	9.35	9.74	4.4
Liquefied Petroleum Gas	8.94	8.13	6.38	6.90	7.63	8.26	8.71	9.19	9.71	10.20	10.76	11.35	11.95	12.61	13.23	6.3
Natural Gas	6.03	5.57	5.34	5.48	5.62	5.77	5.86	6.08	6.39	6.64	6.99	7.22	7.34	7.67	7.87	3.3
Steam Coal	3.07	2.81	2.73	2.76	2.80	2.82	2.84	2.87	2.90	2.94	2.97	3.00	3.03	3.07	3.10	1.1
Electricity	23.01	22.40	22.21	22.49	22.41	22.53	22.39	22.12	22.11	22.13	22.16	22.31	22.48	22.62	22.85	.2
Commercial	**11.96**	**11.47**	**11.28**	**11.61**	**11.71**	**12.00**	**12.12**	**12.26**	**12.55**	**12.82**	**13.15**	**13.46**	**13.71**	**14.06**	**14.36**	**2.0**
Primary Energy	4.91	4.66	4.53	4.60	4.72	4.94	5.09	5.33	5.63	5.91	6.27	6.56	6.75	7.10	7.35	4.1
Petroleum Products	4.42	4.64	4.61	4.90	4.81	5.10	5.39	5.70	6.05	6.42	6.89	7.33	7.75	8.20	8.64	5.4
Distillate Fuel	4.13	4.31	4.72	4.95	4.64	4.89	5.12	5.39	5.70	6.04	6.48	6.87	7.23	7.64	8.02	4.5
Residual Fuel	2.72	3.20	2.44	2.87	3.04	3.26	3.47	3.68	3.92	4.17	4.50	4.80	5.09	5.39	5.68	7.3
Other Petroleum [1]	7.82	7.49	6.65	6.94	7.32	7.82	8.25	8.67	9.10	9.52	10.02	10.54	11.08	11.62	12.14	5.1
Natural Gas	5.27	4.79	4.61	4.59	4.79	5.00	5.09	5.31	5.61	5.85	6.19	6.43	6.54	6.87	7.06	3.6
Steam Coal	1.76	1.60	1.56	1.58	1.60	1.61	1.62	1.64	1.66	1.68	1.70	1.72	1.74	1.76	1.77	1.1
Electricity	22.15	21.06	20.98	21.38	21.21	21.32	21.19	20.92	20.92	20.94	20.98	21.13	21.30	21.46	21.68	.3
Industrial	**5.02**	**4.79**	**4.55**	**4.84**	**4.92**	**5.18**	**5.35**	**5.55**	**5.83**	**6.08**	**6.39**	**6.69**	**6.96**	**7.31**	**7.60**	**4.4**
Primary Energy	3.40	3.31	3.01	3.21	3.30	3.55	3.74	3.97	4.25	4.49	4.81	5.09	5.34	5.67	5.94	5.8
Petroleum Products	4.02	4.22	3.62	4.07	4.06	4.43	4.76	5.07	5.40	5.71	6.10	6.52	6.94	7.36	7.78	6.6
Distillate Fuel	4.11	4.41	3.91	4.18	4.75	4.99	5.23	5.50	5.82	6.16	6.61	6.99	7.36	7.77	8.15	6.3
Liquefied Petroleum Gas	6.21	5.55	4.35	5.16	5.02	5.65	6.09	6.56	7.07	7.56	8.10	8.69	9.28	9.93	10.54	7.7
Motor Gasoline	7.24	7.20	6.98	7.11	7.28	7.69	8.11	8.50	8.89	9.27	9.75	10.24	10.77	11.25	11.74	4.4
Residual Fuel	2.22	2.65	2.24	2.52	2.53	2.75	2.96	3.18	3.42	3.66	3.99	4.29	4.58	4.88	5.16	7.2
Other Petroleum [2]	3.41	3.81	3.34	3.72	3.55	3.87	4.17	4.41	4.65	4.86	5.15	5.47	5.82	6.13	6.45	5.6
Natural Gas	3.25	2.84	2.79	2.81	3.01	3.20	3.29	3.51	3.81	4.05	4.39	4.62	4.73	5.05	5.24	5.4
Metallurgical Coal	2.02	1.80	1.76	1.77	1.80	1.81	1.82	1.84	1.86	1.88	1.90	1.92	1.93	1.95	1.97	.9
Steam Coal	1.74	1.57	1.54	1.56	1.58	1.59	1.60	1.61	1.63	1.65	1.66	1.67	1.69	1.70	1.71	.9
Hydroelectric Power	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	12.31	.0
Electricity	15.19	14.16	14.11	14.52	14.36	14.47	14.34	14.06	14.05	14.06	14.07	14.21	14.38	14.58	14.76	.4
Transportation	**6.66**	**6.85**	**6.42**	**6.61**	**6.95**	**7.29**	**7.64**	**7.97**	**8.32**	**8.66**	**9.11**	**9.55**	**10.00**	**10.44**	**10.87**	**4.5**
Primary Energy	6.65	6.84	6.41	6.60	6.94	7.28	7.63	7.96	8.31	8.65	9.10	9.54	9.99	10.43	10.87	4.5
Petroleum Products	6.65	6.84	6.41	6.60	6.94	7.28	7.63	7.96	8.31	8.65	9.10	9.54	9.99	10.43	10.87	4.5
Distillate Fuel	6.18	6.47	6.13	6.43	6.80	7.04	7.28	7.55	7.86	8.20	8.64	9.03	9.39	9.80	10.18	4.3
Jet Fuel	4.20	4.19	3.81	4.19	4.26	4.56	4.85	5.14	5.44	5.75	6.16	6.55	6.95	7.35	7.74	6.1
Motor Gasoline	7.30	7.46	6.98	7.11	7.54	7.95	8.36	8.75	9.14	9.52	10.00	10.50	11.02	11.50	11.99	4.6
Residual Fuel	2.06	2.55	2.26	2.41	2.42	2.64	2.85	3.07	3.30	3.55	3.88	4.18	4.46	4.76	5.05	6.9
Other Petroleum [3]	19.87	20.19	19.70	20.06	20.07	20.39	20.70	20.95	21.19	21.41	21.69	22.03	22.39	22.70	23.03	1.3
Electricity	20.83	20.09	19.86	20.27	20.31	20.30	20.20	19.93	19.96	20.03	20.16	20.39	20.63	20.92	21.04	.5
Total Energy																
Primary Energy - Four Sectors	5.28	5.22	4.88	5.08	5.29	5.57	5.81	6.09	6.40	6.69	7.08	7.43	7.75	8.14	8.48	4.7
Electricity	20.05	19.15	19.04	19.38	19.25	19.37	19.24	18.95	18.92	18.90	18.89	19.00	19.15	19.30	19.49	.2
Electric Utilities																
Fossil Fuel Average	**1.87**	**1.78**	**1.66**	**1.73**	**1.79**	**1.81**	**1.85**	**1.93**	**2.02**	**2.12**	**2.25**	**2.37**	**2.44**	**2.55**	**2.64**	**3.9**
Petroleum Products	2.63	3.15	2.51	2.99	3.03	3.29	3.52	3.77	4.02	4.25	4.60	4.94	5.26	5.58	5.90	7.4
Distillate Fuel	4.20	4.12	3.96	4.20	4.49	4.72	4.96	5.22	5.54	5.91	6.35	6.74	7.09	7.50	7.88	5.9
Residual Fuel	2.53	3.07	2.38	2.89	2.97	3.21	3.42	3.64	3.88	4.12	4.45	4.75	5.06	5.37	5.67	7.5
Natural Gas	2.44	2.32	2.18	2.59	2.55	2.49	2.60	2.84	3.10	3.39	3.66	3.95	4.11	4.35	4.55	6.3
Steam Coal	1.69	1.56	1.50	1.49	1.56	1.57	1.59	1.60	1.62	1.64	1.65	1.66	1.68	1.69	1.70	1.1
Hydroelectric Power	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.00	.0
Nuclear Power	.80	.80	.78	.76	.73	.70	.67	.65	.63	.62	.60	.59	.59	.58	.57	-2.5
Average Price to All Users																
Petroleum Products	5.77	5.95	5.48	5.79	6.02	6.35	6.68	6.99	7.31	7.63	8.03	8.45	8.89	9.31	9.74	4.9
Distillate Fuel	5.58	5.72	5.46	5.73	6.08	6.32	6.56	6.82	7.13	7.48	7.92	8.30	8.66	9.07	9.45	4.7
Jet Fuel	4.20	4.19	3.81	4.19	4.26	4.56	4.85	5.14	5.44	5.75	6.16	6.55	6.95	7.35	7.74	6.1
Liquefied Petroleum Gas	6.92	6.22	4.87	5.61	5.68	6.30	6.74	7.20	7.70	8.18	8.71	9.29	9.87	10.51	11.12	7.1
Motor Gasoline	7.30	7.45	6.98	7.11	7.53	7.94	8.36	8.74	9.13	9.52	9.99	10.49	11.01	11.49	11.98	4.6
Residual Fuel	2.35	2.84	2.32	2.66	2.72	2.95	3.16	3.38	3.63	3.88	4.23	4.54	4.82	5.13	5.43	7.4
Other Petroleum Products	4.33	4.70	4.32	4.71	4.58	4.90	5.22	5.48	5.73	5.95	6.24	6.58	6.94	7.25	7.57	4.8
Natural Gas	4.17	3.75	3.65	3.76	3.90	4.04	4.11	4.30	4.57	4.80	5.08	5.30	5.40	5.67	5.84	4.0
Coal [4]	1.72	1.58	1.52	1.51	1.58	1.59	1.60	1.62	1.63	1.65	1.66	1.68	1.69	1.71	1.72	1.0
Electricity	20.05	19.15	19.04	19.38	19.25	19.37	19.24	18.95	18.92	18.90	18.89	19.00	19.15	19.30	19.49	.2

[1] Includes liquefied petroleum gas and motor gasoline.
[2] Includes petrochemical feedstocks, still gas, lubricants, waxes, asphalt, special naphthas, and petroleum coke.
[3] Includes liquefied petroleum gas, lubricants, and waxes.
[4] Includes steam coal and metallurgical coal.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C4. Supply and Disposition of Electricity
(Quadrillion Btu)

Fuel Consumption and Disposition	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electric Utilities																
Fuel Inputs																
Oil																
Distillate	0.08	0.09	0.11	0.09	0.05	0.06	0.08	0.11	0.13	0.12	0.16	0.19	0.19	0.20	0.21	5.4
Residual	1.37	1.17	1.21	1.07	1.11	1.15	1.16	1.25	1.37	1.55	1.78	1.86	1.77	1.82	1.81	3.4
Natural Gas	2.69	2.92	2.92	2.92	2.95	2.97	3.28	3.54	3.82	4.09	4.61	4.95	5.36	5.68	6.02	6.2
Steam Coal	14.45	15.19	15.84	16.06	16.26	16.46	16.79	17.21	17.63	18.12	18.22	18.54	18.82	19.14	19.40	1.7
Nuclear Power	4.47	4.92	5.64	5.63	5.78	5.98	5.99	6.04	6.06	6.08	6.10	6.12	6.20	6.22	6.22	.8
Hydropower/Other [1]	3.23	2.81	2.59	3.10	3.26	3.29	3.30	3.31	3.34	3.35	3.36	3.37	3.38	3.38	3.38	2.3
Total Fuel Inputs	**26.30**	**27.09**	**28.31**	**28.87**	**29.41**	**29.91**	**30.59**	**31.46**	**32.35**	**33.31**	**34.23**	**35.03**	**35.73**	**36.43**	**37.04**	**2.3**
Net Imports (fuel input equiv.)	.37	.48	.42	.43	.45	.51	.53	.55	.57	.59	.64	.66	.69	.72	.75	5.1
Total Electricity Inputs	**26.67**	**27.57**	**28.72**	**29.30**	**29.86**	**30.42**	**31.13**	**32.01**	**32.91**	**33.90**	**34.87**	**35.69**	**36.42**	**37.15**	**37.79**	**2.3**
Disposition																
Total Electricity Inputs	26.67	27.57	28.72	29.30	29.86	30.42	31.13	32.01	32.91	33.90	34.87	35.69	36.42	37.15	37.79	2.3
Minus Conversion Losses	18.18	18.79	19.56	19.96	20.35	20.75	21.24	21.84	22.46	23.14	23.81	24.36	24.84	25.31	25.72	2.3
Generation	**8.49**	**8.78**	**9.16**	**9.34**	**9.51**	**9.67**	**9.89**	**10.17**	**10.45**	**10.76**	**11.06**	**11.33**	**11.58**	**11.84**	**12.07**	**2.3**
Plus Nonutility Purchases	.13	.16	.19	.20	.23	.24	.25	.26	.27	.28	.29	.30	.31	.32	.33	4.5
Plus Net Imports (electricity equiv.)	.12	.16	.14	.14	.15	.17	.18	.18	.19	.19	.21	.22	.23	.24	.25	5.1
Minus Trans. & Dist. Losses	.72	.72	.77	.76	.73	.74	.75	.77	.79	.81	.83	.85	.87	.88	.90	1.4
Electricity Sales	**8.02**	**8.38**	**8.72**	**8.93**	**9.15**	**9.34**	**9.56**	**9.84**	**10.12**	**10.43**	**10.72**	**10.99**	**11.25**	**11.51**	**11.75**	**2.5**
Electricity Sales by End-Use Sector																
Residential	2.79	2.90	3.01	3.03	3.10	3.16	3.22	3.30	3.37	3.43	3.49	3.55	3.60	3.66	3.71	1.8
Commercial/Other [2]	2.47	2.60	2.70	2.81	2.90	2.97	3.05	3.14	3.22	3.30	3.38	3.46	3.54	3.61	3.69	2.6
Industrial	2.76	2.88	3.00	3.09	3.16	3.22	3.29	3.40	3.53	3.69	3.85	3.98	4.11	4.23	4.35	3.1
Total Electricity Sales	**8.02**	**8.38**	**8.72**	**8.93**	**9.15**	**9.34**	**9.56**	**9.84**	**10.12**	**10.43**	**10.72**	**10.99**	**11.25**	**11.51**	**11.75**	**2.5**
Nonutilities																
Fuel Inputs for Generation [3]																
Oil	.01	.01	.01	.01	.01	.01	.01	.01	.02	.02	.02	.02	.02	.02	.02	5.9
Gas	.26	.30	.35	.36	.40	.41	.43	.45	.47	.49	.50	.52	.54	.56	.58	4.4
Coal	.15	.17	.19	.20	.21	.22	.23	.24	.26	.27	.28	.30	.31	.33	.34	5.1
Nonfossil [4]	.33	.35	.38	.38	.40	.42	.43	.45	.47	.48	.50	.53	.55	.57	.59	3.9
Disposition of Generated Electricity																
Sales to Utilities	.13	.16	.19	.20	.23	.24	.25	.26	.27	.28	.29	.30	.31	.32	.33	4.5
Own Use	.25	.27	.28	.29	.30	.31	.33	.34	.35	.37	.38	.40	.42	.44	.46	4.2

[1] Includes renewable electric utility energy sources such as hydropower, geothermal power, wood, waste, solar power, and wind power.
[2] Includes street lighting and sales to the transportation sector.
[3] Represents energy content of fuel required for generation.
[4] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Data Report 1960-1986*, DOE/EIA-0214(86); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 637; File Creation Date 12/20/88.

Table C5. Electric Utility Summer Capability and Generation
(Capability in Million Kilowatts)
(Generation in Billion Kilowatthours)

Capability and Generation	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Net Capability [1]																
Coal Steam	291.7	292.8	294.6	296.8	296.9	297.9	299.0	299.1	299.8	301.7	304.0	307.8	310.8	313.7	318.2	0.6
Other Fossil Steam	146.4	145.3	144.7	144.5	144.4	141.0	140.6	139.5	136.5	134.5	133.0	131.6	130.5	129.4	127.9	-1.0
Combined Cycle	5.1	5.1	5.1	5.2	5.3	5.3	6.0	6.8	6.9	7.0	10.3	16.7	23.7	31.5	41.5	19.0
Turbine/Diesel	44.3	44.3	45.0	45.6	45.4	48.4	49.4	50.6	51.8	53.2	54.6	56.3	58.4	60.4	62.7	2.8
Nuclear Power	85.4	93.6	95.1	98.7	99.8	103.0	103.0	103.0	103.0	103.0	103.0	103.0	104.1	104.1	104.0	.7
Hydropower/Other [2]	93.4	93.7	94.3	94.4	95.3	96.0	97.0	97.6	98.4	98.6	98.9	98.9	99.0	99.1	99.2	.4
Total Capability	**666.3**	**674.8**	**678.7**	**685.2**	**687.1**	**691.5**	**694.9**	**696.5**	**696.4**	**698.0**	**703.8**	**714.2**	**726.6**	**738.3**	**753.5**	**.9**
Generation by Plant Type																
Coal Steam	1,386	1,464	1,523	1,548	1,565	1,586	1,620	1,662	1,704	1,754	1,765	1,798	1,828	1,860	1,888	1.8
Other Fossil Steam	363	366	372	354	354	353	374	400	428	463	511	514	515	519	512	2.7
Combined Cycle	14	17	17	16	22	22	25	29	29	29	43	72	104	139	184	22.2
Turbine/Diesel	8	9	9	9	7	12	17	23	31	35	44	56	59	61	64	17.6
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [2]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,788**	**2,835**	**2,899**	**2,981**	**3,064**	**3,155**	**3,241**	**3,320**	**3,394**	**3,470**	**3,538**	**2.3**
Generation by Fuel Type																
Coal	1,386	1,464	1,523	1,548	1,565	1,586	1,620	1,662	1,704	1,754	1,765	1,798	1,828	1,860	1,888	1.8
Natural Gas	249	273	272	271	275	276	304	327	351	374	422	456	501	537	578	6.5
Oil	137	118	126	109	108	111	113	124	137	153	176	186	178	182	182	3.1
Nuclear Power	414	455	522	522	535	553	555	559	560	562	564	566	573	575	576	.8
Hydropower/Other [3]	302	262	241	290	305	308	308	309	311	313	314	314	315	315	315	2.3
Total Generation	**2,487**	**2,572**	**2,684**	**2,739**	**2,788**	**2,835**	**2,899**	**2,981**	**3,064**	**3,155**	**3,241**	**3,320**	**3,394**	**3,470**	**3,538**	**2.3**
Nonutilities																
Generation by Fuel Type [4]																
Residual Oil	1	1	2	2	2	2	2	2	2	2	3	3	3	3	3	5.9
Natural Gas	42	48	56	58	64	66	69	72	75	78	81	84	87	90	93	4.4
Steam Coal	21	24	27	28	30	31	33	34	36	38	40	42	44	46	49	5.1
Nonfossil [5]	48	51	55	56	59	61	64	66	68	71	74	77	80	83	87	3.9
Generation by Use																
Sales to Utilities	37	47	57	59	66	69	72	75	78	82	84	87	90	93	97	4.5
Own Use	75	78	82	84	88	92	95	99	103	108	113	118	123	129	135	4.2

[1] Net summer capability is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2] Includes other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[3] Includes conventional and pumped storage hydropower and other renewable sources such as geothermal power, wood, waste, solar power, and wind power.
[4] Individual fuel inputs converted to Kilowatthours based on average heat rate for each respective fuel.
[5] Nonfossil includes biomass, wood, waste, hydroelectric, solar, geothermal, wind, and other.
Notes: Historical values are through 1987, except for nonutilities, which are estimates. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C6. Electric Utility Summer Capability Additions
(Thousand Kilowatts)

Additions	High World Oil Price Case														
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Additions															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	3,838	5,324	4,099	3,993	5,490	36,810
Combined Cycle [2]	0	14	20	153	0	681	767	164	102	3,243	6,395	7,060	7,819	9,924	36,343
Turbines [3]	263	709	589	58	2,999	1,105	1,241	1,311	1,501	1,507	1,684	2,191	1,949	2,374	19,219
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total New Capability	**930**	**5,504**	**6,817**	**2,960**	**9,954**	**3,967**	**3,017**	**3,783**	**5,116**	**8,823**	**13,446**	**14,552**	**13,864**	**17,891**	**109,693**
Announced/Planned Construction [4]															
Nuclear Power [1]	8,268	2,346	3,574	1,186	3,340	0	0	0	0	0	0	1,152	0	0	11,598
Coal Steam	2,125	1,798	2,340	612	2,894	1,213	401	1,489	3,319	2,382	2,188	672	142	602	20,052
Combined Cycle [2]	0	14	20	153	0	681	767	164	102	288	28	102	0	0	2,319
Turbines [3]	263	709	589	58	153	58	66	90	64	225	286	434	278	77	3,087
Hydropower/Other	274	637	294	951	721	968	608	819	194	235	42	50	102	102	5,723
Total Planned	**930**	**5,504**	**6,817**	**2,960**	**7,108**	**2,920**	**1,842**	**2,562**	**3,679**	**3,130**	**2,544**	**2,410**	**522**	**781**	**42,779**
Additional Needed Capability [5]															
Nuclear Power [1]	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Steam	0	0	0	0	0	0	0	0	0	1,456	3,136	3,427	3,851	4,888	16,758
Combined Cycle [2]	0	0	0	0	0	0	0	0	0	2,955	6,367	6,958	7,819	9,924	34,024
Turbines [3]	0	0	0	0	2,846	1,047	1,175	1,221	1,437	1,282	1,398	1,757	1,671	2,297	16,132
Total Additional Needed	**0**	**0**	**0**	**0**	**2,846**	**1,047**	**1,175**	**1,221**	**1,437**	**5,693**	**10,902**	**12,142**	**13,342**	**17,110**	**66,914**

[1] Nuclear capability is as of the date the unit first delivers power to the grid; all other capability is as of the date the unit begins commercial service.
[2] Includes natural gas, oil, and dual-fired oil/natural gas combined cycle capability.
[3] Includes all gas turbine and internal combustion capability.
[4] Includes all new capability announced by the electric utility industry.
[5] Includes additional new capability considered necessary by the Energy Information Administration to meet electricity demands.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C7. Electric Utility Sales, Prices, and Price Components
(Billion Kilowatthours)
(1988 Dollars per Thousand Kilowatthours)

Sales, Prices, and Price Component	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Electricity Sales by End-Use Sector																
Residential	818	850	884	888	909	925	945	968	987	1,005	1,024	1,041	1,056	1,074	1,089	1.8
Commercial/Other [1]	725	761	792	825	849	869	894	920	944	968	992	1,014	1,036	1,059	1,081	2.6
Industrial	808	845	881	905	925	943	963	995	1,035	1,083	1,128	1,167	1,204	1,240	1,274	3.1
Total Electricity Sales	**2,351**	**2,456**	**2,556**	**2,618**	**2,683**	**2,737**	**2,802**	**2,884**	**2,965**	**3,056**	**3,143**	**3,222**	**3,297**	**3,373**	**3,444**	**2.5**
Prices [2]																
Residential	78.53	76.45	75.80	76.73	76.47	76.86	76.40	75.46	75.44	75.52	75.63	76.12	76.69	77.17	77.97	.2
Commercial/Other [1]	75.54	71.84	71.56	72.92	72.35	72.72	72.28	71.36	71.36	71.45	71.57	72.09	72.66	73.21	73.96	.3
Industrial	51.83	48.31	48.13	49.53	49.01	49.38	48.94	47.99	47.95	47.98	48.02	48.50	49.07	49.74	50.38	.4
All Sectors	**68.43**	**65.33**	**64.95**	**66.12**	**65.70**	**66.08**	**65.65**	**64.67**	**64.55**	**64.47**	**64.44**	**64.84**	**65.33**	**65.84**	**66.50**	**.2**
Price Components																
Capital Component [3]	32.48	30.92	30.20	31.57	31.19	31.09	30.39	28.93	28.17	27.32	26.23	25.68	25.60	25.32	25.24	-1.5
Fuel Component [4]	16.98	16.68	15.88	15.75	15.64	16.18	16.58	17.24	18.01	18.91	20.10	21.12	21.76	22.61	23.38	3.3
O&M Component [5]	18.97	19.08	18.86	18.93	18.87	18.81	18.69	18.51	18.37	18.25	18.11	18.05	17.98	17.91	17.89	-.4
Total Price [2]	**68.43**	**66.68**	**64.94**	**66.25**	**65.70**	**66.08**	**65.65**	**64.67**	**64.55**	**64.47**	**64.45**	**64.85**	**65.34**	**65.85**	**66.50**	**.2**

[1] Includes consumption for street and highway lighting, other public authorities, and railways.
[2] Prices for 1988 to 2000 are estimated from model simulations and represent average revenues per kilowatthour of demand for the total electric utility industry.
[3] Represents the cost to the utility of capital assets needed to promote reliable service. It includes plant depreciation, taxes, and sufficient return on invested capital to cover interest obligations on outstanding debt and to compensate stockholders.
[4] Includes only the direct costs of fuel inputs used to generate electricity required to meet demand.
[5] 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.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Calculated from the Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); Office of Coal, Nuclear, Electric and Alternate Fuels; values for 1988 are estimates. Forecasts: Based on Forecast Run 637; File Creation Date 12/20/88.

Table C8. Petroleum Supply and Disposition Balance
(Million Barrels per Day)

Supply and Disposition	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1] (1988 dollars per barrel)	**14.92**	**18.70**	**14.70**	**17.10**	**18.00**	**19.10**	**20.20**	**21.20**	**22.80**	**24.40**	**26.50**	**28.60**	**30.80**	**32.90**	**35.00**	**7.5**
Production																
Crude Oil [2]	8.68	8.35	8.18	8.06	7.73	7.47	7.25	7.10	6.90	6.79	6.70	6.70	6.69	6.71	6.77	-1.6
Alaska	1.87	1.96	2.03	2.03	1.96	1.86	1.78	1.74	1.61	1.53	1.45	1.41	1.32	1.25	1.18	-4.4
Lower 48	6.81	6.39	6.15	6.04	5.78	5.61	5.47	5.37	5.29	5.26	5.26	5.29	5.36	5.46	5.59	-.8
Natural Gas Liquids	1.55	1.60	1.61	1.62	1.65	1.68	1.70	1.72	1.73	1.74	1.77	1.79	1.82	1.83	1.85	1.2
Other Domestic	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.06	.6
Processing Gain [3]	.62	.64	.66	.65	.65	.63	.62	.61	.61	.61	.61	.60	.60	.60	.60	-.8
Total Production	**10.90**	**10.65**	**10.51**	**10.40**	**10.10**	**9.85**	**9.64**	**9.50**	**9.30**	**9.20**	**9.14**	**9.17**	**9.17**	**9.21**	**9.29**	**-1.0**
Imports (Including SPR [4])																
Crude Oil	4.18	4.67	5.12	5.31	5.70	5.92	6.04	6.22	6.50	6.75	6.92	6.94	6.95	7.04	7.05	2.7
Refined Products	2.05	2.00	1.96	2.06	2.09	2.12	2.14	2.17	2.21	2.25	2.30	2.32	2.31	2.32	2.32	1.4
Total Imports	**6.22**	**6.67**	**7.08**	**7.37**	**7.79**	**8.04**	**8.18**	**8.38**	**8.71**	**9.00**	**9.22**	**9.25**	**9.26**	**9.36**	**9.37**	**2.4**
Exports																
Crude Oil	.15	.15	.17	.17	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	.19	1.3
Refined Products	.63	.61	.64	.62	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.63	.0
Total Exports	**.78**	**.76**	**.80**	**.79**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.83**	**.2**
Net Imports	**5.44**	**5.91**	**6.28**	**6.58**	**6.97**	**7.22**	**7.35**	**7.56**	**7.88**	**8.18**	**8.40**	**8.43**	**8.43**	**8.53**	**8.55**	**2.6**
Primary Stock Changes [5]																
Net Withdrawals	-.15	.04	.04	.01	.00	.01	.01	-.01	-.02	-.03	-.03	-.02	.00	-.02	-.02	
SPR [4] Fill Rate (-)	-.05	-.08	-.05	-.05	-.08	-.08	-.08	-.08	-.08	-.08	-.03	.00	.00	.00	.00	
Total Primary Supply [6]	**16.14**	**16.52**	**16.78**	**16.94**	**16.99**	**17.00**	**16.94**	**16.98**	**17.09**	**17.27**	**17.48**	**17.58**	**17.60**	**17.72**	**17.82**	**.5**
Refined Petroleum Products																
Motor Gasoline	7.03	7.21	7.34	7.39	7.31	7.19	7.07	7.01	6.98	6.97	6.97	6.95	6.94	6.95	6.95	-.5
Jet Fuel [7]	1.31	1.37	1.44	1.48	1.50	1.51	1.51	1.53	1.55	1.57	1.59	1.60	1.61	1.63	1.64	1.1
Distillate Fuel [8]	3.01	3.07	3.22	3.28	3.31	3.34	3.37	3.40	3.43	3.46	3.50	3.54	3.57	3.59	3.62	1.0
Residual Fuel	1.42	1.26	1.25	1.16	1.20	1.21	1.20	1.23	1.28	1.36	1.45	1.48	1.44	1.45	1.45	1.2
Other Petroleum Products [9]	3.52	3.76	3.76	3.69	3.73	3.76	3.78	3.81	3.85	3.90	3.95	4.00	4.04	4.10	4.16	.8
Total Product Supplied	**16.29**	**16.67**	**17.01**	**17.00**	**17.04**	**17.00**	**16.93**	**16.97**	**17.09**	**17.27**	**17.48**	**17.57**	**17.60**	**17.72**	**17.81**	**.4**
Refined Petroleum Products Supplied by Sector																
Residential/Commercial	1.35	1.37	1.41	1.41	1.40	1.39	1.37	1.36	1.34	1.33	1.31	1.29	1.28	1.27	1.26	-.9
Industrial	4.09	4.30	4.30	4.23	4.27	4.30	4.31	4.34	4.38	4.44	4.49	4.54	4.58	4.64	4.70	.7
Transportation	10.22	10.46	10.73	10.86	10.86	10.78	10.71	10.68	10.70	10.77	10.82	10.84	10.87	10.93	10.98	.2
Electric Utilities	.63	.55	.58	.51	.50	.53	.54	.60	.66	.73	.85	.90	.86	.88	.88	3.6
Total Consumption	**16.29**	**16.67**	**17.01**	**17.00**	**17.04**	**17.00**	**16.93**	**16.97**	**17.09**	**17.27**	**17.48**	**17.57**	**17.60**	**17.72**	**17.81**	**.4**
Discrepancy [10]	**-.15**	**-.15**	**-.23**	**-.06**	**-.05**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	
Net Disposition [11]	**16.14**	**16.52**	**16.78**	**16.94**	**16.99**	**17.00**	**16.94**	**16.98**	**17.09**	**17.27**	**17.48**	**17.58**	**17.60**	**17.72**	**17.82**	**.5**

[1] Represents the cost of imported crude oil to U.S. refiners.
[2] Includes lease condensate.
[3] Represents volumetric gain in refinery distillation and cracking processes.
[4] SPR is the Strategic Petroleum Reserve.
[5] A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[6] Equals total production plus net imports plus net stock withdrawals minus SPR fill rate.
[7] Includes naphtha and kerosene type.
[8] Includes kerosene.
[9] Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, plant condensate, pentanes plus, asphalt and road oil, still gas, special naphthas, petroleum coke, unfinished oils, and miscellaneous petroleum products.
[10] Represents the difference between total primary supply and total consumption.
[11] Represents the sum of total consumption and discrepancy.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C9. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet)
(1988 Dollars per Thousand Cubic Feet)

Supply, Disposition, and Prices	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Production																
Dry Gas Production	15.99	16.54	16.71	16.71	16.85	16.67	16.88	16.99	17.08	17.24	17.56	17.75	18.05	18.16	18.35	0.8
Supplemental Gas [1]	.11	.10	.17	.18	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	.10	-4.3
Net Imports	**.69**	**.94**	**1.15**	**1.32**	**1.44**	**1.54**	**1.62**	**1.71**	**1.81**	**1.91**	**2.01**	**2.09**	**2.18**	**2.27**	**2.36**	**6.2**
Net Storage Withdrawals [2]	**-.15**	**.00**	**.04**	**.05**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	**.00**	
Total Supply [3]	**16.65**	**17.57**	**18.07**	**18.26**	**18.38**	**18.31**	**18.60**	**18.80**	**19.00**	**19.24**	**19.67**	**19.94**	**20.33**	**20.53**	**20.81**	**1.2**
Consumption by Sector																
Residential	4.30	4.32	4.59	4.66	4.61	4.57	4.56	4.53	4.47	4.43	4.36	4.33	4.31	4.26	4.23	-.7
Commercial [4]	2.31	2.41	2.61	2.65	2.64	2.63	2.66	2.65	2.63	2.63	2.60	2.61	2.63	2.61	2.63	.1
Industrial	5.60	5.89	6.15	6.24	6.21	6.21	6.17	6.15	6.12	6.13	6.10	6.05	6.00	5.93	5.86	-.4
Lease & Plant Fuel [5]	.92	1.15	1.01	1.03	1.02	.99	1.00	1.00	1.01	1.02	1.04	1.05	1.07	1.08	1.09	.7
Transportation [6]	.48	.52	.55	.54	.50	.49	.49	.49	.50	.51	.52	.52	.53	.54	.54	-.1
Electric Utilities	2.61	2.84	2.83	2.83	2.86	2.88	3.18	3.43	3.71	3.97	4.47	4.80	5.20	5.51	5.85	6.2
Total Consumption	**16.23**	**17.13**	**17.75**	**17.95**	**17.85**	**17.77**	**18.06**	**18.26**	**18.45**	**18.68**	**19.09**	**19.36**	**19.74**	**19.93**	**20.20**	**1.1**
Unaccounted for [7]	**.41**	**.45**	**.32**	**.31**	**.54**	**.53**	**.54**	**.55**	**.55**	**.56**	**.57**	**.58**	**.59**	**.60**	**.61**	
Average Wellhead Price	**2.06**	**1.72**	**1.62**	**1.64**	**1.85**	**2.07**	**2.24**	**2.52**	**2.81**	**3.09**	**3.46**	**3.67**	**3.85**	**4.10**	**4.32**	**8.5**
Average Price by Sector																
Residential	6.21	5.74	5.50	5.65	5.79	5.94	6.04	6.27	6.58	6.84	7.20	7.44	7.56	7.90	8.11	3.3
Commercial [4]	5.43	4.93	4.75	4.73	4.94	5.15	5.25	5.47	5.78	6.03	6.38	6.62	6.74	7.07	7.27	3.6
Industrial	3.35	2.93	2.87	2.90	3.10	3.30	3.39	3.61	3.92	4.17	4.52	4.76	4.87	5.20	5.40	5.4
Electric Utilities	2.52	2.39	2.25	2.67	2.63	2.57	2.68	2.92	3.19	3.49	3.77	4.07	4.23	4.48	4.69	6.3
Average to All Sectors [8]	**4.36**	**3.93**	**3.81**	**3.93**	**4.08**	**4.21**	**4.28**	**4.48**	**4.75**	**4.99**	**5.27**	**5.50**	**5.60**	**5.88**	**6.06**	**3.9**

[1] Includes synthetic natural gas (results from the manufacture, conversion, or the reforming of petroleum hydrocarbons), and propane-air mixtures.
[2] Includes net withdrawals of dry natural gas from underground storage and liquefied natural gas. A negative (-) result represents an increase to inventories and a decrease to total supply. A positive result represents a withdrawal from inventories and an increase to total supply.
[3] Total supply represents the sum of dry gas production, supplemental gas, net imports, and net storage withdrawals.
[4] Includes deliveries to municipalities and other public authorities for use in schools and other institutions.
[5] Represents natural gas used in gathering systems and processing plants.
[6] Represents natural gas used to fuel compressors in pipeline pumping stations.
[7] Represents the difference between total supply and total consumption.
[8] Weighted average price. The weights used are the sectoral consumption values excluding lease and plant fuel and the transportation sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding. Commercial and industrial natural gas prices for 1989, reflect base case values from PC-AEO Model run 635.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C10. Coal Supply, Disposition, and Prices
(Million Short Tons)
(1988 Dollars per Short Ton)

Supply, Disposition, and Prices	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
Total Production [1]	890	919	941	946	980	998	1,013	1,038	1,063	1,093	1,096	1,117	1,132	1,149	1,162	1.8
Imports	2	2	2	2	3	4	4	4	5	5	5	5	6	6	7	10.1
Exports [2]	86	80	86	82	86	90	94	98	102	106	107	108	109	110	111	2.2
Net Imports	-83	-78	-84	-80	-83	-86	-90	-94	-97	-101	-102	-103	-103	-104	-104	1.9
Net Storage Withdrawals [3]	-4	-6	17	17	-3	-8	-4	-6	-6	-7	-1	-4	-4	-4	-4	
Total Supply [4]	803	834	875	882	894	903	918	938	959	985	992	1,009	1,025	1,040	1,054	1.6
Consumption by Sector																
Residential/Commercial	8	7	7	7	7	7	7	7	7	7	7	7	7	7	6	-1.0
Industrial	76	75	75	75	74	74	74	74	75	76	77	78	80	81	82	.7
Coking Plants	36	37	39	39	38	38	37	36	36	36	36	36	36	35	35	-1.0
Electric Utilities	685	718	750	760	774	785	801	821	842	866	872	888	902	918	931	1.8
Total Consumption	804	837	872	882	894	903	918	938	959	985	992	1,009	1,025	1,040	1,054	1.6
Discrepancy [5]	-1	-3	3	0	0	0	0	0	0	0	0	0	0	0	0	
Average Minemouth Price [6]	25.36	23.79	23.61	23.77	24.34	24.51	24.68	24.89	25.14	25.41	25.48	25.68	25.84	26.00	26.14	.9
Delivered Price by Sector																
Residential/Commercial	52.08	48.19	46.32	46.76	47.31	47.55	47.84	48.23	48.72	49.27	49.62	50.09	50.54	51.03	51.46	.9
Industrial	38.20	34.76	34.92	35.22	35.60	35.66	35.89	36.20	36.42	36.86	37.10	37.46	37.62	37.95	38.10	.7
Coking Plants	54.18	48.01	47.15	47.57	48.18	48.50	48.86	49.31	49.84	50.45	50.82	51.35	51.81	52.28	52.76	.9
Electric Utilities	35.49	32.95	31.74	31.62	32.83	33.01	33.24	33.55	33.86	34.24	34.42	34.75	34.99	35.24	35.52	.9
Average to All Sectors [7]	36.74	33.91	32.82	32.75	33.83	33.99	34.19	34.47	34.77	35.14	35.33	35.65	35.88	36.13	36.38	1.0

[1] Includes anthracite, bituminous coal, and lignite.
[2] Excludes small quantities of anthracite shipped overseas to U.S. Armed Forces.
[3] From all stocks held by industrial plants, coke plants, electric utilities, and producers/distributors. A negative (-) result represents an increase to inventories. A positive result represents a withdrawal from inventories.
[4] Represents the sum of production, net imports, and net storage withdrawals.
[5] Represents the difference between total supply and total consumption.
[6] Free on board (F.O.B.) mines.
[7] Weighted average prices. The weights used are consumption values by sector.
Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.
Sources: Historical data: Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); *State Energy Price and Expenditure Report 1986*, DOE/EIA-0376(86); *Quarterly Coal Report*, DOE/EIA-0121(88/2Q); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Table C11. National Macroeconomic Indicators

Macroeconomic Indicators	High World Oil Price Case															Annual Pct. Growth
	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	1988-2000
World Oil Price [1]																
1988 dollars per barrel	14.92	18.70	14.70	17.10	18.00	19.10	20.20	21.20	22.80	24.40	26.50	28.60	30.80	32.90	35.00	7.5
Nominal dollars per barrel	14.00	18.13	14.70	17.73	19.69	22.06	24.63	27.21	30.76	34.57	39.53	44.86	50.72	56.83	63.20	12.9
1982 dollars per barrel	12.29	15.40	12.11	14.09	14.83	15.73	16.64	17.46	18.78	20.10	21.83	23.56	25.37	27.10	28.83	7.5
Economic Variables																
Real GNP (billion 1982 dollars)	3,722	3,847	4,001	4,116	4,211	4,300	4,387	4,483	4,597	4,730	4,859	4,963	5,078	5,207	5,335	2.4
Real Disposable Income (billion 1982 dollars)	2,641	2,687	2,787	2,860	2,916	2,969	3,023	3,081	3,147	3,220	3,295	3,360	3,429	3,502	3,575	2.1
Real Disposable Income per Capita (thousand 1982 dollars)	10.9	11.0	11.3	11.5	11.7	11.8	11.9	12.0	12.2	12.4	12.6	12.8	13.0	13.1	13.3	1.3
GNP Implicit Price Deflator (1982=1.00)	1.139	1.177	1.214	1.259	1.328	1.402	1.480	1.558	1.638	1.720	1.811	1.904	1.999	2.097	2.192	5.0
Unemployment Rate (percent)	7.0	6.2	5.4	5.2	5.4	5.6	5.9	6.2	6.4	6.4	6.4	6.6	6.9	7.1	7.2	
Population, Noninstitutional (million persons)	241.3	243.5	245.6	247.8	250.0	252.1	254.2	256.2	258.1	259.9	261.7	263.5	264.6	266.8	268.4	.7
New AA Bond Rate (percent per annum)	8.94	9.50	10.26	11.19	10.77	10.95	10.82	10.34	10.32	10.32	10.40	10.42	10.36	10.29	10.14	
Energy Usage Indicators																
Gross Energy Use (quadrillion Btu)	74.3	76.8	79.4	80.2	80.7	80.9	81.4	82.2	83.1	84.3	85.4	86.2	87.1	87.9	88.6	.9
Gross Energy Use per Capita (million Btu per person)	307.8	315.5	323.4	323.5	322.6	321.0	320.4	320.9	322.0	324.3	326.2	327.3	329.0	329.3	330.2	.2
Gross Energy Use per Dollar of GNP (thousand Btu per 1982 dollar)	20.0	20.0	19.9	19.5	19.2	18.8	18.6	18.3	18.1	17.8	17.6	17.4	17.1	16.9	16.6	-1.5
Gross Petroleum and Natural Gas Use per Dollar of GNP (thousand Btu per 1982 dollar)	13.2	13.1	12.9	12.6	12.3	12.0	11.9	11.6	11.5	11.2	11.2	11.0	10.8	10.6	10.5	-1.7
Energy/GNP Rate of Change (percent)																
1985-1990	-1.3															
1985-1995	-1.4															
1985-2000	-1.4															
1990-1995	-1.4															
1995-2000	-1.4															
1988-2000	-1.5															

[1] Represents the cost of imported crude oil to U.S. refiners.

Notes: Historical values are through 1987. Totals may not equal sum of components due to independent rounding.

Sources: Historical data: Data Resources, Inc., USMODEL database (October 1988); Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035(88/07); values for 1988 are estimates. Forecasts: Based on Run 637; File Creation Date 12/20/88.

Appendix D

Data Sources

Data Sources for Figures

In general all historical data can be found in the *Annual Energy Review 1987*, DOE/EIA-0384(87) (Washington, DC, 1988). For specific figures, the following data sources were used:

Figure 1. World Oil Prices
History: *Annual Energy Review 1987.* Projections: Table A1.

Figure 2. Opec Oil Production and Free World Demand
History: *Annual Energy Review 1987.* Projections: *International Energy Outlook 1989*, DOE/EIA-0484(89).

Figure 3. World Oil Reserves
History: *Oil and Gas Journal*, December 28, 1987.

Figure 4. Energy Intensity in Selected Countries
History: *Annual Energy Review 1987.* Projections: *International Energy Outlook 1989.*

Figure 5. United States Economic Growth
History: U.S. Department of Commerce, Bureau of Economic Analysis, *Survey of Current Business.* Projections: Table A11.

Figure 6. U.S. Energy Intensity
History: *Annual Energy Review 1987.* Projections: Table A11.

Figure 7. Petroleum Supply and Consumption
History: *Annual Energy Review 1987.* Projections: Table A8.

Figure 8. New Car Fuel Efficiency
History: U.S. Department of Transportation, *Highway Statistics Summary to 1985.* Oak Ridge National Laboratory, 1988, ORNL-6496, *Light-Duty Vehicle MPG and Market Shares Report: First Six Months of Model Year 1988.* Projections: Internal forecast, Office of Energy Markets and End Use, EIA.

Figure 9. Ratio of Cash Flow to Fixed Assets
History and Projections: Table 2.

Figure 10. Natural Gas Consumption and Production
History: *Annual Energy Review 1987.* Projections: Tables A9, B9 and C9.

Figure 11. Natural Gas Consumption by End Use
History: *Annual Energy Review 1987.* Projections: Table A9, B9, and C9.

Figure 12. Delivered Prices for Oil Products and Natural Gas
History: *Annual Energy Review 1987.* Projections: Tables A3, B3, and C3.

Figure 13. Additions to Electric Utility Generating Capability
History: *Annual Energy Review 1987.* Projections: Table A6.

Figure 14. Growth Rates for Electricity Sales
History: *Annual Energy Review 1987.* Projections: Table A2.

Figure 15. Changes in Utility and Non-Utility Generation by Plant Type
Projections: Table A5.

Figure 16. Changes in Utility Generation of Electricity by Fuel
Projections: Table A5.

Figure 17. Components of Average Electricity Price
Projections: Table A7.

Figure 18. Domestic Coal Use
Projections: Table A10.

Figure 19. Change in Assumed Growth, Oil Price, and Energy Intensity
Projections: Table 3 and Table 4.

Figure 20. Change in Consumption of Major Fuels
Projections: Table 5.

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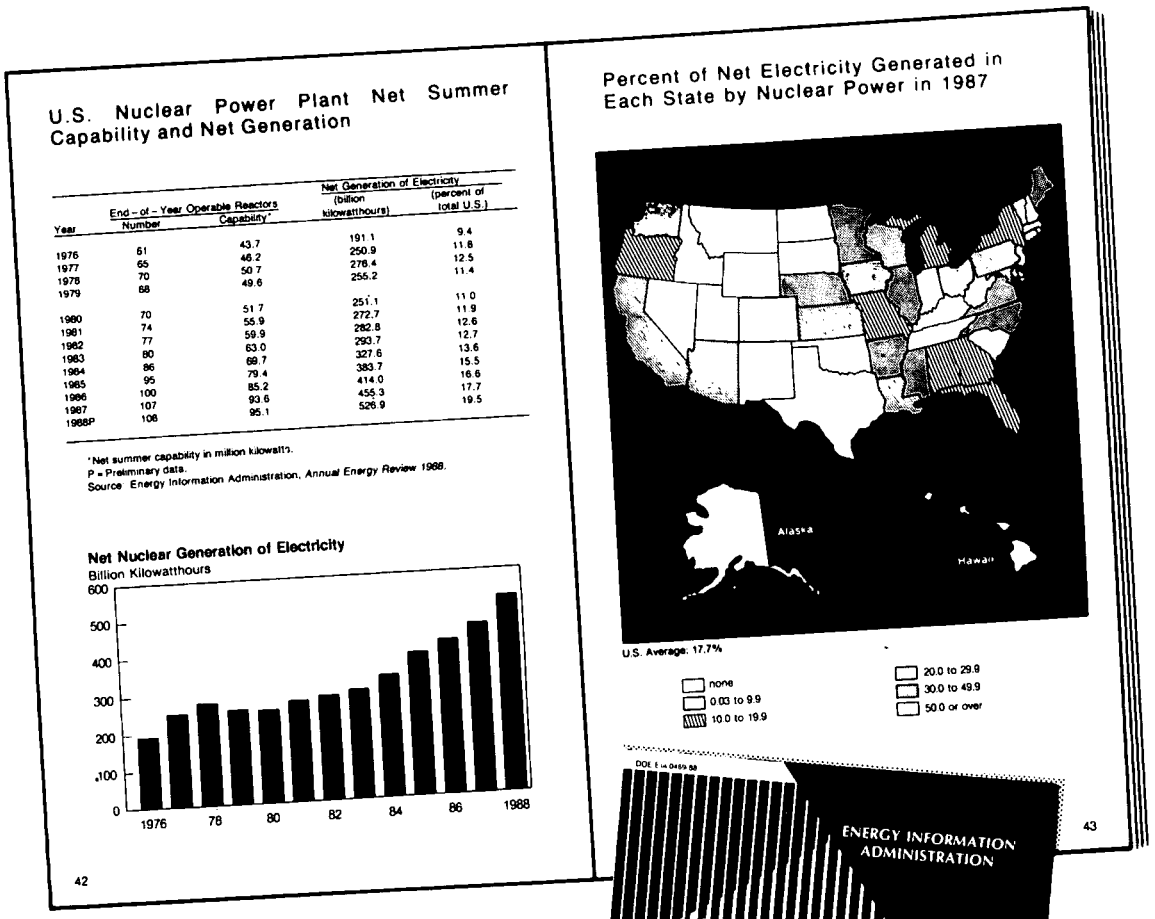

U.S. Nuclear Power Plant Net Summer Capability and Net Generation

Year	End-of-Year Operable Reactors Number	Capability*	Net Generation of Electricity (billion kilowatthours)	(percent of total U.S.)
1976	61	43.7	191.1	9.4
1977	65	46.2	250.9	11.8
1978	70	50.7	276.4	12.5
1979	68	49.6	255.2	11.4
1980	70	51.7	251.1	11.0
1981	74	55.9	272.7	11.9
1982	77	59.9	282.8	12.6
1983	80	63.0	293.7	12.7
1984	86	69.7	327.6	13.6
1985	95	79.4	383.7	15.5
1986	100	85.2	414.0	16.6
1987	107	93.6	455.3	17.7
1988P	108	95.1	526.9	19.5

*Net summer capability in million kilowatts.
P = Preliminary data.
Source: Energy Information Administration, *Annual Energy Review 1988*.

Net Nuclear Generation of Electricity
Billion Kilowatthours

42

Percent of Net Electricity Generated in Each State by Nuclear Power in 1987

43

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