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Supply 77
EPRI Annual Energy Supply Forecasts

EA-634-SR

Special Report, May 1978

Prepared by

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ABSTRACT

Domestic energy production and prices by fuel type, as well as imports, are projected for the 1975-2000 period. Natural gas production is expected to increase gradually to 1990 and then decline. Output of domestic petroleum liquids, including shale oil, peaks in the 1990-1995 period and then declines. Shale oil output reaches one million barrels a day by the end of the century. Coal production capability increases throughout the period, reaching 2.6 billion tons per year by the year 2000, providing markets develop for this output level. Nuclear power growth is expected to accelerate above present trends later in the century, reaching 380 gigawatts in the year 2000. At this level, nuclear power would produce as much electricity as the burning of an additional 1.3 billion tons of coal.

A reference electric power case and two other levels of output are presented. These levels of output are analyzed in connection with reference levels of fuel and construction costs, as well as variations on these reference levels. Measured in constant 1976 dollars, average revenue requirements per kilowatthour for electric power output range from a likely low of 3.52 cents per kilowatthour to a likely high of 3.99 cents per kilowatthour, with a reference case figure of 3.71 cents. The comparable figure for 1976 was 2.89 cents.

FOREWORD

This report provides estimates of domestic energy production and imports through the year 2000, given certain assumptions about federal energy policy. These assumptions were embodied in the calculations made for this report in the fall of 1977. At present (May 1978), many of the policy-related assumptions are still unsettled. It now appears that natural gas prices will be lower initially than assumed, but they will rise over time instead of being constant at the higher level. Current indications are that natural gas prices will be deregulated in 1985 instead of being regulated through the year 2000. The petroleum calculations were made on an assumption that the administration's proposed crude oil equalization tax (COET) would be enacted. This is now in doubt. However, if COET is not enacted by Congress, alternative measures, such as petroleum import fees or possible increases in the allowed wellhead price of domestic crude oil, may be taken. These might result in petroleum product prices similar to those projected here. Certainly, the administration believes that higher petroleum product prices are necessary in order to help restrict the growth of petroleum demand.

Conceptually, the report pulls together the results of research under EPRI contract, other relevant research, and the experience and knowledge of the Supply Program staff. Since this forecast is a first effort and much of the fundamental contract research has not yet been finished, the pulling together is far from complete. Future editions of this report are planned.

A companion report, Demand 77, was published in March 1978. (Demand 77 and other EPRI reports referenced herein may be obtained from the Research Reports Center, P.O. Box 10090, Palo Alto, California 94303. For a complete listing of EPRI reports, request the EPRI publications list.)

Supply 77 places on record the basic forecasts of energy supply to the year 2000 that were provided to EPRI's Planning Staff for their use in preparing the Institute's research plan. It also makes these forecasts available to electric utilities and others, for both their use and their criticism. This exchange can help produce more accurate and more usable forecasts in the coming year. In addition, the report provides documentation and some explanation of the rationale of the forecasts.

Although the basic thrust of the analysis and the level and direction of the projections are believed to be correct, a number of improvements should be made in future versions: The time horizon should be extended to 2030 to meet the needs of the EPRI R&D Planning Staff. At the same time, the near-term (15-year) analysis should be strengthened to meet more immediate utility needs. Measures of uncertainty and perhaps alternative forecasts based on different assumptions should be made. However, the work must clearly indicate the Supply Program's expectations as to the future course of energy supply. It should not be simply a recitation of alternative cases.

The supply analysis should also provide expanded geographic coverage. On the one hand, regional detail and forecasts should be included. On the other, increased emphasis must be placed on world supply prospects because--directly and indirectly--world supply considerations will continue to affect the U.S. economy. Supply from undeveloped resource types (e.g., oil shale) and from new technologies (e.g., solar) must receive increased attention. In this report, which extends only to the year 2000, these resources and technologies were largely ignored in the belief that their contribution to energy supply before 2000 would be quite limited. In the year 2030, however, energy from new technologies may well be the major if not the dominant source of energy supply.

Future forecasts should also incorporate more of the contract research work and efforts by others. Time did not permit the full incorporation of much of the available research. Further, because the volume of available research is growing rapidly, these efforts will become increasingly important in the years ahead.

Making projections of energy supply from technologies sponsored by EPRI will require closer coordination between the Supply Program and the "hardware" divisions of EPRI to ensure consistency between our projections and their technological evaluations. In addition, more effort on the policy and intangible aspects of energy supply will be required in future forecasts since these factors are more determinative, at least in the next few decades, of price and output than such factors as resource endowments and resource depletion.

Future forecasts should be made available on a more timely basis. There is currently too long a period (about six months) between the time the basic work on the forecasts is completed and their publication. For Planning Staff use of the forecasts, this is not a serious problem because the forecasts are to some extent developed and provided in an interactive mode with the Planning Staff. However, for utility and public use, delay reduces the value of the forecasts.

Milton F. Searl, Manager
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SUMMARY

Energy supply has been responding to the economic incentives that came into being in the wake of the Arab oil embargo of 1973-1974. The precursors of new production are reflecting the expectation of higher prices. Drilling for oil and gas ended a 16-year decline in 1974 and has been on the increase ever since; exploratory and development drilling for uranium has shown remarkable strength in spite of uncertainties about the future of nuclear power; and there has been much activity directed at developing new coal reserves, particularly in the West.

Concern has been expressed in some quarters because energy production, particularly crude oil and natural gas production, did not increase immediately in response to higher prices. However, since existing production capacity normally declines at roughly 10% per year, and since it takes time to get new drilling programs under way, an immediate increase in production was not to be expected. It now appears that the production of crude oil (even excluding Alaskan) and natural gas, which had been declining, has now leveled off and may increase during 1978.

For crude oil, natural gas, uranium, and perhaps to some extent for coal, it is necessary to distinguish between intermediate-term production (or production capability) response and long-term response. Much of the new production capability developed in the past few years has been at what economists call the intensive rather than the extensive margin. That is, we have been drilling new oil and gas wells in areas where resources known to exist were uneconomic to recover at lower prices, and we have also been drilling more wells in existing fields to increase the extraction rate. For uranium, we have been developing lower-grade, higher-cost deposits which were not economic at older, lower uranium prices.

If economic theory holds in the present situation, which seems probable, then as effort is focused more on the extensive margin--as well-conceived new exploration and development programs begin to show results--resources somewhat more prolific than those brought into production in the past few years should be developed.

Expansion of domestic energy production to date has been hampered by uncertainty about federal energy policy. Of particular concern is the prospect that federal policy, when it is made, will place greater emphasis on conservation than on increasing energy supply. A strong conservation policy is necessary for the near term. However, without an equally strong policy favoring expanded domestic output, the nation runs a grave risk of serious energy shortages and continued dependence on imported oil in the long run.

The projections contained in this report assume that crude oil and natural gas prices will be close to those proposed by President Carter. It should be noted that the Congress may produce a substantially modified policy. Basically, the assumptions are of continued price controls on crude oil and natural gas. The proportion of production from new wells which meets the "new oil" definition is assumed to be at the 1977 price of imported oil (about $13.50 in real 1976 dollars) in 1980, and constant thereafter, except for some adjustment allowed for inflation. Natural gas which meets "new gas" criteria is assumed to be priced at $2.00 per thousand cubic feet. It appears that Congress will propose such a price, as compared with the $1.75 price recommended by President Carter. These constant dollar prices, which are not tied to future world oil prices in the president's plan, are assumed to prevail for the remainder of the century. If these assumptions are correct, our analysis indicates that oil and natural gas drilling will peak in the next few years and then decline through the remainder of the century.

Our analysis indicates that primary energy production will not be limited by resource shortages between now and the year 2000. However, the timely development of production from these resources is subject to many uncertainties. Depending on the resolution of these uncertainties, production could be well below or above the projected level. Even if the projected levels are achieved, the amount of imports will continue to increase, possibly with detrimental economic effects. These projections indicate about 50% of oil consumption and about 25% of natural gas consumption in the nation will be met by imports in the year 2000. Output levels, particularly for crude oil and natural gas, are forecast to be well below what might be achieved with higher prices. For the word <u>prices</u>, we might more correctly substitute <u>maintenance of profit levels</u>, since much of the revenue produced by high prices already goes to governments and others in the form of lease bonuses, royalties, and taxes. The basic results are given below.

Our reference case for electric power generation by electric utilities envisages production of 6.25 trillion kilowatthours (kWh) in the year 2000 versus 2.04 trillion in 1976. Results reported in the base case of a companion EPRI study--Demand 77 (EA-621-SR)--indicate that production of about 7.5 trillion kilowatt-hours is to be expected by the end of the century. We also provide figures on average revenue requirements per kilowatthour, generating capacity, and fuel consumption for such output levels, as well as for lower levels.

Table S-1 shows expected electricity prices (average revenue requirements per kilowatthour) for various expansion cases. Capacity mix and fuel consumption projections are summarized in Tables S-2 and S-3, respectively. Figure S-1 presents average revenue requirements in constant 1976 dollars; Figure S-2 shows some of the same data in current dollars, assuming 5% per year inflation. It is important to note that, in all cases, real prices throughout the period are rising less rapidly than in the past few years, and that the rate of increase is declining through the period. Furthermore, the bulk of the 1975-2000 real price increase occurs before 1985. These forecast prices are actually calculated as utility costs, including a normal rate of return. It is assumed that regulation allows these costs to be passed on in prices. As with all supply projections, there exists considerable uncertainty about costs of fuel, plant, and operation and maintenance.

Tables S-4 and S-5 summarize the projections of primary energy production under the assumptions of this report. Our estimates tend to be somewhat more optimistic than most forecasts for domestic oil and natural gas production. Also, the world oil picture is improving, and substantial quantities of foreign crude oil are expected to be available at only moderate increases in real prices.

Constant dollar projected prices for fossil fuels are summarized in Table S-6. All prices except for coal FOB the mine are forecast to increase throughout the period. As indicated in the report, prices for most coals will increase, but an increasing proportion of western coal in the national mix will stabilize and in some cases decrease national average prices. Delivered natural gas prices are predicted to more than double. Petroleum prices will increase by about 50% from 1976, except for residual fuel oil prices, which were depressed in 1976 and thus will show a greater percentage increase.

Table S-1

SELECTED PROJECTIONS: AVERAGE REVENUE PER KILOWATTHOUR
(cents/kWh)

	1975	1985	2000
Constant 1976 dollars			
Lowest likely	2.86	3.29	3.52
Reference	2.86	3.39	3.71
Highest likely	2.86	3.45	3.99
Current dollars, 5%/yr inflation			
Lowest likely	2.70	5.36	11.92
Reference	2.70	5.52	12.56
Highest likely	2.70	5.62	13.51

Table S-2

YEAR-END REFERENCE CASE CAPACITY MIX
(GW)

	1976	2000
Steam		
Coal	(215)	560
Oil	(130)	196
Natural gas	(70)	5
Conventional steam subtotal	415	761
Nuclear power	43	380
Hydropower	68	72
Other*	5	51
Total	531	1264

Source: Edison Electrical Institute, Statistical Yearbook, 1976, except figures in parentheses. EEI does not provide these figures. The figures in parentheses are National Electric Reliability Council figures adjusted to EEI conventional steam totals. EEI uses maximum nameplate ratings, whereas NERC uses actual ratings, and EEI apparently puts some combustion turbine capacity in the conventional steam category.

*Includes internal combustion, solar, geothermal, and so on.

Table S-3

REFERENCE CASE
FOSSIL FUEL CONSUMPTION BY ELECTRIC UTILITIES

	1975	2000
Coal (million tons)	406	1490
Oil (million barrels)	507	1080
Gas (trillion cubic feet)	3.2	1.6

Note: This table assumes 6.25 trillion kilowatthours of generation and 380,000 MW (e) of nuclear power in the year 2000.

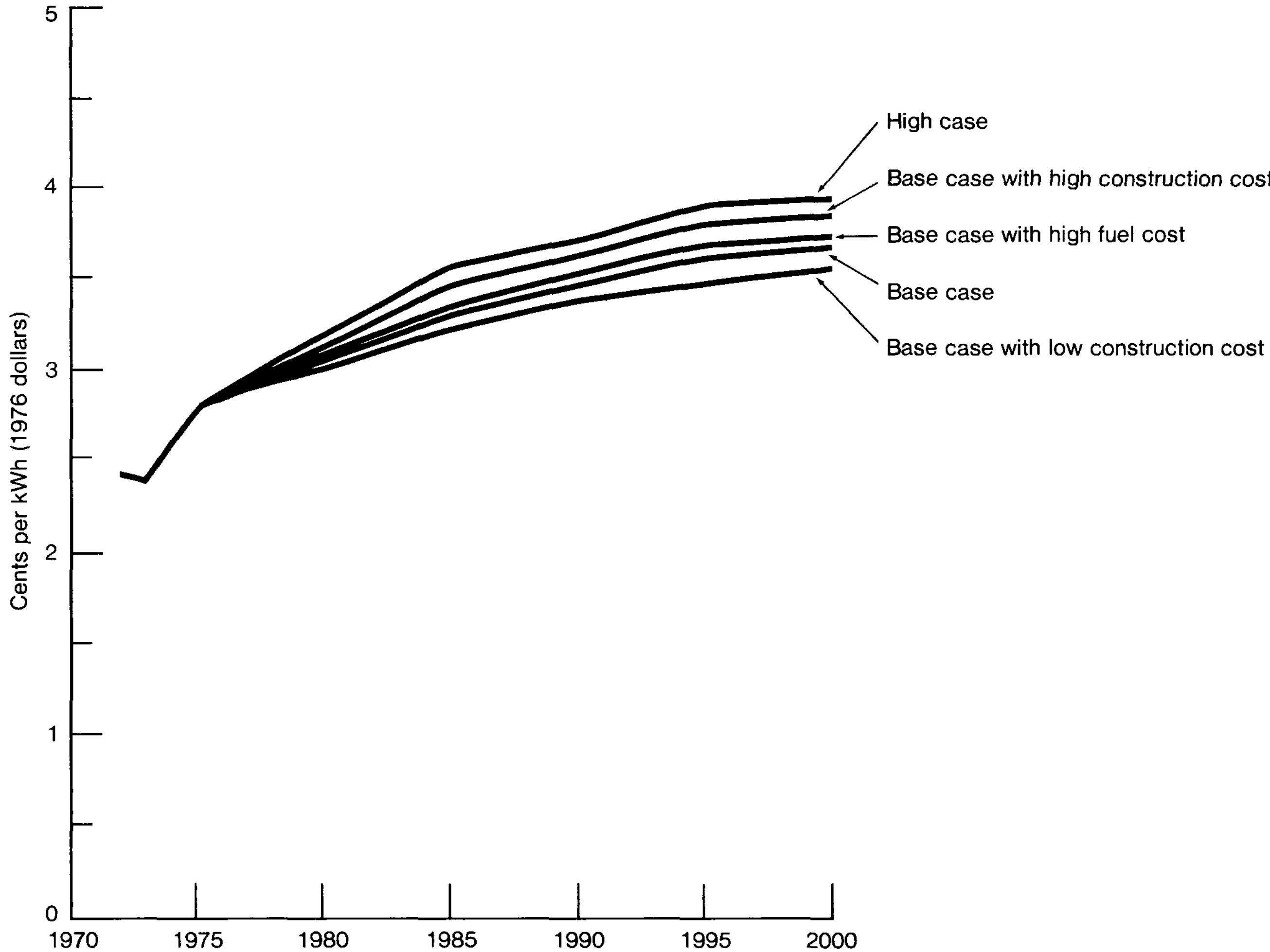


Figure S-1. Average Revenue per Kilowatthour (in constant 1976 dollars)

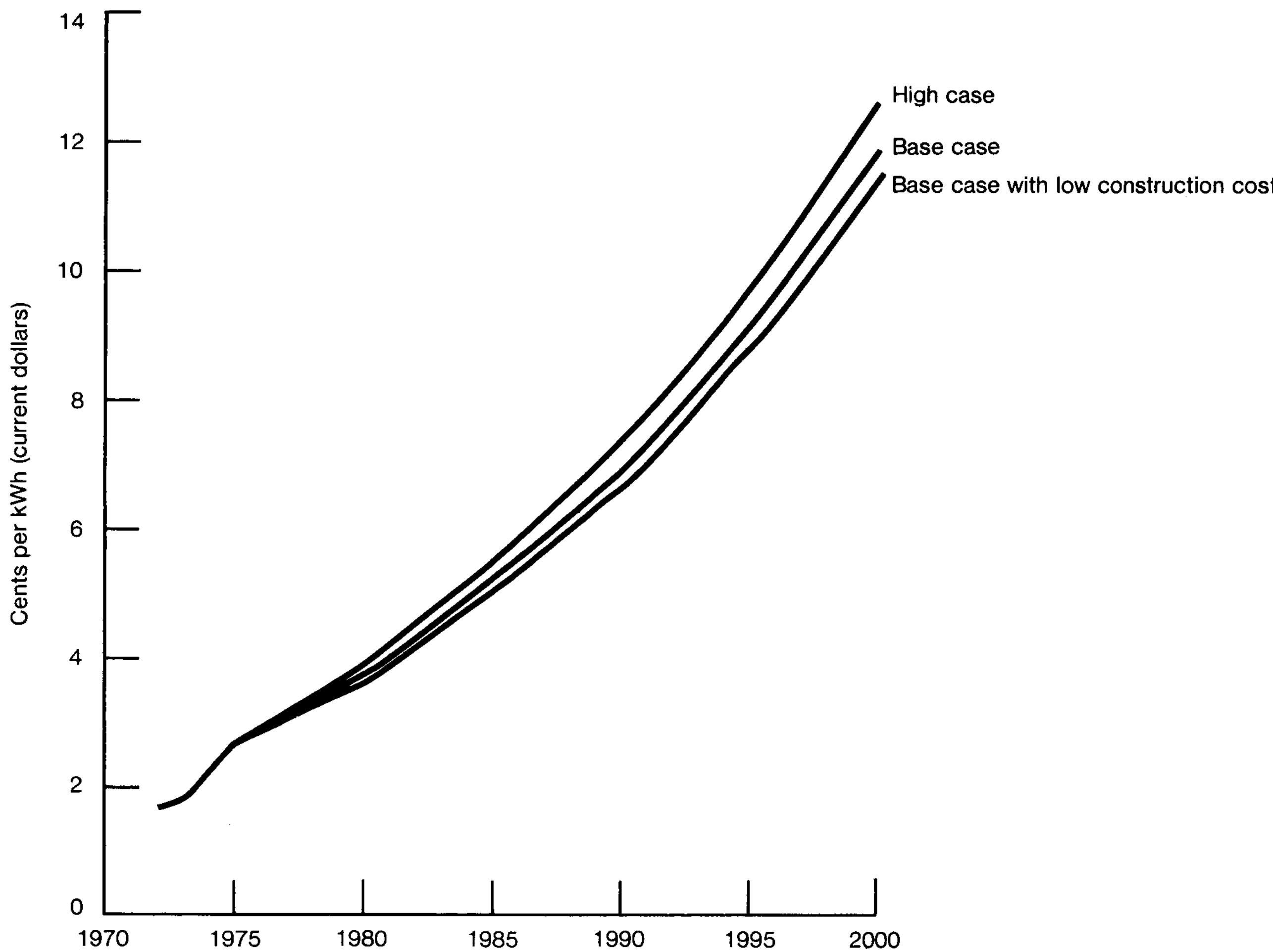


Figure S-2. Average Revenue per Kilowatthour (in current dollars at 5%/yr inflation)

Table S-4

DOMESTIC ENERGY PRODUCTION: MAJOR SOURCES
(natural units)

	1975	1980	1985	1990	1995	2000
Gas (trillion cubic feet)[a]	19.2	20.2	22.4	23.2	21.9	18.9
Petroleum liquids[b] (million barrels per day)	10.4	11.0	11.3	13.0	13.0	11.9
Coal (million tons)	655	800	1000	1320[d]	1910[d]	2600[d]
Nuclear power (coal equivalent)[c] (million tons)	76	162	355	611[d]	922[d]	1266[d]
Hydropower (coal equivalent)[c] (million tons)	132	156	157	170	175	187

[a]Dry gas basis.

[b]Includes natural gas liquids and refinery processing gain (net).

[c]The average Btu content of coal production expected in the year and a heat rate of 10,000 Btu per kilowatthour are used for the equivalency calculations.

[d]Contingent upon realization of power generation of 7.0 trillion kilowatthours in year 2000, which is the baseline case without natural gas supply restrictions in Demand 77 (EA-621-SR) and is close to the high demand case in this study, not to the reference case.

Table S-5

DOMESTIC ENERGY PRODUCTION: MAJOR SOURCES
(quadrillion Btu)

	1975	1980	1985	1990	1995	2000
Gas[a]	22.0	23.1	25.7	26.5	25.0	21.5
Petroleum liquids	17.7	18.8	19.4	23.2	24.1	23.3
Coal	15.4	16.4	21.6	27.9[d]	40.3[d]	54.1[d]
Hydropower[b]	3.2	3.2	3.4	3.6	3.7	3.9
Nuclear power[b]	1.8	3.5	7.3	13.2[d]	19.5[d]	26.3[d]
Total[c]	60.1	65.0	77.4	94.4	112.6	129.1
Consumption	70.6	82.2	97.1	113.5	133.3	157.8
Net imports	10.5	17.2	19.7	19.1	20.7	28.7

[a] Wet gas basis.

[b] At 10,000 Btu/kWh.

[c] Other sources not included. They are unlikely to be more than a small percentage of the total by the year 2000.

[d] Contingent upon realization of power generation of 7.0 trillion kilowatthours in year 2000, which is the baseline case without natural gas supply restrictions in Demand 77 (EA-621-SR) and corresponds to the high demand case in this study, not to the reference case.

Table S-6

PROJECTED FOSSIL FUEL PRICES
(1976 dollars)

	1976	1980	1985	1990	1995	2000
Domestic natural gas (delivered, $/thousand cubic feet)	1.29	2.13	2.83	3.06	3.22	3.35
Motor gasoline (pump price, ¢/gal)	59	67	68	70	72	75
Distillate fuel oil (residential, delivered, ¢/gal)	16.86	20.20	20.90	21.60	22.80	24.00
Residual fuel oil (retail, including utility, $/bbl)	11.77	16.05	16.60	17.15	18.20	19.25
Coal* (FOB mine, $/ton)	18.93	18.50	17.50	18.50	18.00	17.55

*National coal figures tend to be misleading due to a shifting mix of lower price and quality western coal and coal from the interior and Appalachian fields. Indeed, all coal prices can be rising, and the national average declining.

Section 1

GAS SUPPLY

NATURAL GAS

Natural gas consists of the hydrocarbon methane (CH_4). Commercially, small amounts of somewhat heavier hydrocarbons may be included, as well as trace amounts of other gases. The basic unit of measurement in the United States is a cubic foot at standard temperature and pressure. The heating value of a cubic foot is about 1032 Btu.

Conventional Sources

Natural gas is currently produced from naturally occurring underground reservoirs which are primarily the result of the decomposition of minute marine organisms deposited many millions of years ago. In order to have a natural gas field or reservoir, there must have been at one time a source bed in which the organic remains were deposited. The gas may still be in place where the organisms were deposited, or it may have migrated long distances through the rocks, ultimately to be trapped in reservoir rock with an impermeable rock cap that prevented further migration. The porosity and permeability of the reservoir rock are key factors governing the quantity and production rates of gas deposited in the reservoir (1).

Oil is produced from the same marine organisms as gas. Most natural gas today is the end product of the long decomposition of the organic remains under temperature and pressure, producing a sequence of ever-lighter hydrocarbons, until eventually methane is reached. As a consequence of this evolutionary procedure, oil and natural gas may be found in the same reservoir in any combination. Sometimes large amounts of gas are dissolved in the oil; at other times, the gas is at the top of the reservoir, essentially as a cap on the oil. In still other cases, the gas may exist independently of oil; similarly, some reservoirs are essentially all oil, with very little gas.

As a result of the varying combinations of oil and gas in reservoirs, wells may produce almost any combination of oil and natural gas. However, it is normally possible for a well to be completed and operated in a manner that will selectively favor either oil or gas production. Historically, in oil fields with associated or dissolved gas, the rate of gas production has been limited in order to maintain pressure in the reservoir. This pressure assists in bringing the oil to the surface with a minimum expenditure of outside energy.

There has been, in the past, some controversy about the ability of petroleum companies to selectively drill oil or natural gas wells. This selectivity has been referred to as directionality. In areas that have very little exploration history, there will be considerable uncertainty as to whether an exploratory well, if a producer at all, will yield primarily oil or primarily gas. However, in producing provinces that are more or less established, there is normally considerable information available that enables the operator to predict with some confidence the relative probabilities of oil and gas production. In particular, in fields which are already producing, the type of output to be expected from additional wells in the field can be predicted with high accuracy. Consequently, companies can, with considerable success, direct exploration and development to the production of either crude oil or natural gas.

About 80% of the nation's current natural gas reserves are in nonassociated reservoirs--that is, reservoirs from which oil is not simultaneously produced. About 20% of the reserves are either associated with or dissolved in the crude oil in oil fields. Production of associated and dissolved gas is a function of crude oil production. Nonassociated natural gas production is a product in its own right and responsive to separate supply and demand forces. Table 1-1 shows proven reserves of natural gas by categories for the postwar period, as well as production and certain other information.

Estimates of the amount of natural gas remaining to be discovered and produced vary widely. Some of the current estimates are shown in Table 1-2. There is a basic uncertainty about the amount of natural gas still undiscovered. Some estimates can be made on a geologic basis. However, even with the geologically based estimates, it is necessary to remember that they are largely a function of historical discovery and production figures that were produced in a past economic environment. In an economic environment where gas prices are much higher, it may well be that estimates of remaining gas resources based on historical data will prove to be biased on the low side. The Supply Program is studying the resources

Table 1-1

NATURAL GAS SUPPLY AND PRODUCTION: U.S. TOTAL FOR 1945-1976
(trillion cubic feet at 60°F and 14.73 psia)

	Annual Gross Additions to Proved Reserves	Cumulative Discoveries	Preliminary Annual Net Production	Cumulative Net Production	Proved Reserves	Gas in Underground Storage	Proved Reserves: Annual Production Ratio
1945	--	233.18	--	86.35	146.99	0.15	--
1946	17.63	250.18	4.92	91.26	159.70	0.15	32.46
1947	10.92	261.74	5.60	96.36	165.03	0.15	29.47
1948	13.82	275.56	5.98	102.84	172.93	0.20	28.92
1949	12.61	288.16	6.21	109.05	179.40	0.29	28.89
1950	11.99	300.15	6.86	115.91	184.58	0.34	26.91
1951	15.97	316.12	7.92	123.83	192.76	0.47	24.34
1952	14.27	330.38	8.59	132.42	198.63	0.67	23.12
1953	20.34	350.73	9.19	141.61	210.30	1.18	22.88
1954	9.55	360.27	9.38	150.99	210.56	1.27	22.45
1955	21.90	382.17	10.06	161.05	222.48	1.36	22.12
1956	24.72	406.89	10.85	171.90	236.48	1.49	21.80
1957	20.01	426.89	11.44	183.34	245.23	1.67	21.44
1958	18.90	445.79	11.42	194.76	252.76	1.73	22.13
1959	20.62	466.41	12.37	207.13	261.17	1.89	21.11
1960	13.89	480.31	13.02	220.15	262.33	2.17	20.15
1961	17.17	497.47	13.38	233.53	266.27	2.33	19.90
1962	19.48	516.96	13.64	247.17	272.28	2.49	19.96
1963	18.16	535.12	14.55	261.71	276.15	2.74	18.98
1964	20.25	555.37	15.35	277.06	281.25	2.94	18.32
1965	21.32	576.69	15.25	293.31	286.47	3.09	17.63
1966	20.22	596.91	17.49	310.81	289.33	3.22	16.54
1967	21.80	618.72	18.38	329.19	292.91	3.38	15.94
1968	13.70	632.41	19.37	348.56	287.35	3.49	14.83
1969	8.38	640.79	20.72	369.28	275.11	3.60	13.28
1970	37.20	677.99	21.96	391.24	290.75	4.00	13.24
1971	9.83	687.81	22.08	413.32	278.81	4.31	12.63
1972	9.63	697.45	22.51	435.83	266.08	4.47	11.82
1973	6.83	704.27	22.61	458.44	249.94	4.12	11.05
1974	8.68	712.95	21.32	479.76	237.13	3.94	11.12
1975	10.48	723.43	19.72	499.47	228.20	4.24*	11.57
1976	7.56	--	19.80	--	215.96	--	--

Source: American Gas Association.

Note: The small inconsistencies between annual and cumulative production are caused by rounding of values.

*Proved recoverable gas contained in underground storage reservoirs (first reported on a recoverable basis in 1973).

Table 1-2

NATURAL GAS RESOURCE ESTIMATES--CONVENTIONAL SOURCES
(trillion cubic feet)

	USGS (1974)[a]			Exxon (1974) Base			Exxon (1974) Currently Attainable[b]			Potential Gas Committee (1976)
	Low	Expected	High	Low	Expected	High	Low	Expected	High	
Past production	--	477	--	--	477	--	--	477	--	516
Reserves	--	237	--	--	237	--	--	237	--	216
Inferred	--	202	--	56	111	321	56	111	321	215[c]
Subtotal	--	439	--	293	348	558	293	348	558	431
To be discovered	322	484	655	342	582	942	127	287	657	733
Remaining recoverable	761	923	1094	635	930	1500	420	635	1215	1164
Ultimate recoverable	1238	1400	1571	1112	1407	1977	897	1112	1692	1680

Note: Estimates generally assume that, on the average, 80-85% of the gas in a field is recoverable. These data exclude most gas from degasification of coal beds, Devonian shales, other tight (low-permeability) formations, geopressure zones, and gas hydrates (frozen methane). Small amounts from some of these sources may be included. The estimates also differ somewhat as to offshore depths included.

[a]Figures are based on " . . . a continuation of price-cost relationships and technological trends generally prevailing in the recent years prior to 1974. Price-cost relationships since 1974 were not taken into account because of the yet undetermined effect they may have on resource estimates." U.S. Geological Survey Circ. 725, p. 1.

[b]Assumes normal technological growth and no significant change in economic incentives.

[c]Potential Gas Committee "probable resources." The term may have a somewhat different meaning from "inferred."

of all of the energy forms and will subsequently publish estimates of its own for all energy resources, including natural gas. Such estimates may or may not differ from existing estimates.

It does not appear that natural gas production will be resource-limited through the year 2000 in the case considered here; however, cumulative production plus required reserves at the end of the period make up a sufficient fraction of some of the lower resource estimates to raise questions whether the gas will be available at projected prices. The geographic distribution of the gas resources estimated by the Potential Gas Committee (PGC) of the American Gas Association (AGA) is shown in Table 1-3. Most of the figures appear to assume only normal technological growth and limited economic incentives. These figures do not include unconventional sources.

Unconventional Sources

Estimates of natural gas to be found in so-called unconventional sources are very large. Devonian shales in the East, tight gas formations in the West, coal seams, geopressure zones, and gas hydrates are considered unconventional sources. Actually, there is no clear dividing line between the unconventional and the conventional sources of gas. To some extent, gas is already being produced from the first three sources listed above and has been produced experimentally from geopressure zones. The primary difference between conventional and unconventional sources is an economic one, and perhaps technological as well, in the sense that somewhat different technologies may be required for the widespread commercial development of these sources. Unlike oil, some gas is of nonmarine origin. There are thus potentially more sources of gas than of oil. Estimates of unconventional resources are shown in Table 1-4.

NATURAL GAS SUPPLY

Domestic

Future natural gas supply (production and price) is uncertain on many accounts. Over the long term, the natural gas resource endowment will play a determining role; however, within the next couple of decades, and perhaps longer, the resource endowment is unlikely to be a major factor limiting supply, although resource characteristics will, of course, affect costs and prices. There is uncertainty in the geologic sense as to the difficulty of finding new gas reserves; it is not known, for example, how many cubic feet of gas will be found per foot of exploratory footage drilled. There is also uncertainty as to the future cost of

Table 1-3

U.S. GAS RESOURCES AS ESTIMATED BY THE POTENTIAL GAS COMMITTEE
(trillion cubic feet)

	Resource Category				Conditional Total
	Reserves	Probable	Possible	Speculative	
Eastern states and offshore Atlantic[a]	6	25	9	68	108
Alabama, Mississippi, Florida and offshore[b]	2	5	6	40	53
Illinois, Indiana, Michigan, Minnesota, Iowa, Maryland, Wisconsin[c]	2	0	4	2	8
Arkansas, N. Louisiana, N. Texas[d]	13	8	21	25	67
Louisiana and offshore	55	49	69	0	173
Texas Gulf Coast and offshore[e]	34	39	50	4	127
Northern Rocky Mountains[f]	8	15	31	18	72
Arizona, New Mexico (except Permian Basin)[g]	8	2	3	2	15
Kansas, Oklahoma, Texas Panhandle[h]	33	27	72	8-58	140-190
Permian Basin[i]	18	18	37	1	74
Alaska	32	23	45	157	257
California and offshore, Washington, Idaho, Oregon, Nevada[j]	5	4	16	20	45
Total	216	215	363	345-395	1139-1189

Source: Based on Potential Gas Committee estimates published in Oil and Gas Journal, May 9, 1977, p. 13.

Note: None of the resource figures are certain. Each comes from an unknown probability distribution. They are additive only under certain restrictive conditions. One such (reasonable) condition assumed here is that each figure is an expected value. The variance (uncertainty) about each expected value increases, going from Reserves to Speculative by category, or cumulatively. Where allocation of reserves is unclear, see subsequent footnotes.

[a]The following states assumed to be encompassed: Virginia, West Virginia, Pennsylvania, New York, Kentucky, and Ohio. Reserves are negligible in Maryland, and no reserves are estimated in North Carolina, South Carolina, Georgia, and New England.

[b]No reserves estimated for Florida offshore.

[c]No reserves estimated for Wisconsin; Minnesota, Iowa, and Missouri reserves are negligible.

[d]North Texas reserves assumed to encompass Texas Railroad Commission (TRC) Districts 1, 5, 6, 7B, and 9.

[e]Texas Gulf Coast assumed to encompass TRC Districts 2, 3, and 4.

[f]Northern Rocky Mountains reserves assumed to encompass Montana, North Dakota, Wyoming, and South Dakota (South Dakota reserves are negligible); they are also assumed to include some southern Rocky Mountain and other states, such as Colorado, Utah, and Nebraska.

[g]Reserves encompass only northwest New Mexico; Arizona reserves are negligible.

[h]Texas Panhandle assumed to encompass TRC District 10.

[i]Permian Basin encompasses southern New Mexico and TRC Districts 7C, 8, and 8A.

[j]Washington, Idaho, Oregon, and Nevada reserves are negligible.

Table 1-4

UNCONVENTIONAL SOURCES OF NATURAL GAS

Source	Estimated Volume in Place (trillion cubic feet)	Commercial Production	Major Issues	Major R&D Effort	Forecast Date: High-Volume Commercial Production
Degasification of coal beds	300[a]-800[b]	Limited commercial production in Appalachian coal regions since 1949	Low flow rate; Btu value of recovered gas	Bureau of Mines development program	1990
Devonian shale	500-600[c]	Commercial wells in Kentucky, Ohio, and West Virginia since 1921	Low flow rate; small volume of gas recoverable from a well	DOE Columbia project in West	1990
Other tight formations	600[d]	Successful commercial production in Colorado since 1972	Inability to predict the results of massive fracturing	DOE program in advanced fracturing techniques	1985
Geopressure zones	3000[e]-50,000[f]	None	Unknown methane concentrations; large volume of water production required; unknown environmental impact	DOE drilling and flow test programs	2000
Gas hydrates[g]	30×10^6 [h]	None	Resource and technology largely unevaluated in the United States	USSR successfully demonstrated gas production from northern region	Not estimated

Source: American Gas Association, Gas Supply Review, March 1977, p. 7.

[a]Maurice Deul, "Natural Gas from Coalbeds," in Board on Mineral Resources, Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, D.C., 1976.

[b]Gary E. Voelker, Energy Research and Development Administration, November 1976.

[c]USGS estimate, Gas Supply Review, February 1976.

[d]National Gas Survey, Vol. II--Supply, Federal Power Commission, 1973, p. 95.

[e]Bill R. Hise, "Natural Gas from Geopressured Aquifers," in Board on Mineral Resources, Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, D.C., 1976.

[f]Paul H. Jones, "Natural Gas Reserves of the Geopressured Zones in the Northern Gulf of Mexico Basin," in Board on Mineral Resources, Natural Gas from Unconventional Geologic Sources, National Academy of Sciences, Washington, D.C., 1976.

[g]Low-temperature methane/ice-water mixtures.

[h]UNITAR--II, ASA Conference, United Nations Institute for Training and Research, Vol. 1, No. 5, September 1976.

exploratory and developmental drilling. Drilling costs, like power plant construction costs, have been escalating rapidly (2). This escalation is due in part to general inflation and in part to gradually increasing drilling depths, environmental costs, and government policies (e.g., leasing). There is also a cost component due simply to the rapid expansion of oil and natural gas drilling in the past few years. The physical effort of drilling even for a given depth will increase as exploration and development shift to more remote areas, to areas where the rocks are harder, or to other areas where, for one reason or another, drilling is more difficult.

Higher prices make it economical to drill additional (in-fill) wells in some fields with wide spacing (e.g., 320 or 640 acres). The extent of such in-fill drilling is currently unknown. This drilling increases current output and, to varying degrees, also increases reserves.

For the foreseeable future, natural gas prices will be determined by government policy. Proposed administration policy is to allow $1.75 per thousand cubic feet for new gas, with this price rising with the average refiner acquisition price of domestic crude oil. Gas from older wells receives varying lesser prices, depending upon its vintage and contract terms.

The initial definition of new gas proposed by President Carter was administrative in nature--that is, gas from wells more than 2.5 miles from existing production, or 1000 feet deeper, would be considered new. Geologically, such criteria have no significance, although in general it was hoped they would be roughly correct. More recently, it has been proposed that new reservoirs (the geologically correct concept, but one which will be more difficult to determine promptly) be included in the definition if certified by state regulatory authorities (but subject to reversal by federal authorities). No one knows with any great degree of certainty what proportion of new gas wells will qualify for the $1.75 price. From an aggregative analytic standpoint, then, the average price of gas from new wells is uncertain. Even if price response were perfectly known (and it surely isn't), there would still be supply uncertainty.

Production from specific categories of high-cost gas (e.g., tight gas formations in the West, Devonian shales in the East, and geopressure zones in the Gulf Coast) may receive higher prices, possibly up to the price of alternative pipeline sources of gas such as imported liquefied natural gas (LNG) and synthetic natural gas (SNG) produced from light petroleum fractions. Such prices may be around

$3.50 per thousand cubic feet. Although such special pricing mechanisms are better than nothing, producers may well be wary; government policy is likely to seek to prevent "windfall gain" on actual production from unconventional sources without compensating for losses realized by ventures seeking to produce from unconventional sources but failing to achieve commercial production.

Production of gas from future offshore drilling is subject not only to geologic and economic uncertainties but also to uncertainties regarding government leasing policy and environmental limitations. Consequently, such production is most difficult to predict, although as concern about energy supply grows, it seems likely that the pressure to develop offshore resources will increase. Within limits, and depending on producer expectations, there are some trade-offs between onshore and offshore development. Delayed offshore development may result in somewhat earlier development of poorer onshore properties.

"Reserves" of natural gas on the Alaskan North Slope are 26 trillion cubic feet. Additional discoveries are quite possible (see Table 1-3). Plans are currently under way to lay a pipeline to bring North Slope gas to the lower 48 states and possibly to pick up some Canadian gas along the way. The delivered cost of this gas will likely be higher than the delivered cost of other domestic gas, but the government will likely allow prices to be set to permit its utilization. One source estimates transportation costs to the United States in 1984 at $1.68 per thousand cubic feet (3). Assuming a $1.75 wellhead price, this would indicate a price of about $3.45 per thousand cubic feet for gas delivered to the United States border.

Imports

By Pipeline. Natural gas will be imported overland by pipeline from Canada and Mexico and in liquefied form, as LNG, from overseas. Imports of Canadian gas have been declining, and the prospects for Canadian imports have appeared bleak. However, various developments, including the prospect of hundreds of trillions of cubic feet of low-pressure gas in low-porosity formations, have increased the chances of expanding imports in the future.

The development of large gas reserves in connection with the Reforma oil fields in Mexico has led to active proposals for a major pipeline to the United States. Substantial amounts of gas could be flowing by 1980 or shortly thereafter. Six domestic gas utilities have been negotiating for the gas. (Subsequent to the preparation of our forecast, the new Department of Energy (DOE) indicated opposition to the proposed price, and the future is now unclear.)

By Tanker. Vast natural gas resources (over 7000 trillion cubic feet) are believed to exist overseas. These are just beginning to be exploited. The generally preferred method of moving this gas to the United States and many other major consuming areas is to liquefy the gas and ship it by tanker. The gas may also be converted to methanol and imported in that form. A number of U.S. companies have plans for importing LNG, although in many cases proposed movements have been delayed due to the need for federal approval of the domestic use (and price) and due to environmental difficulties in siting facilities.

LNG imports are, in terms of historical domestic gas prices, a high-cost source of gas. Foreign reserves are generally controlled by the same countries controlling foreign oil, and wellhead prices are thus set at relatively high levels. In addition, expensive facilities are required to liquefy the gas, to ship it, and to regasify it at the consuming end. The Federal Power Commission (FPC), now Federal Energy Regulatory Commission (FERC), recently approved sale of imported LNG at $3.37 per thousand cubic feet. Suggestions have been made by a government advisory committee that LNG imports be limited to 2 trillion cubic feet per day for national security reasons. DOE is presently dealing with imports on a case-by-case basis without any commitment to an overall national level.

GAS FROM CONVERSION PROCESSES

Synthetic Natural Gas

Synthetic natural gas is currently produced in the United States on a very limited scale (0.3 trillion cubic feet in 1976) as a supplement to other sources of gas at the time of gas utility system peaks. This SNG, produced from petroleum feedstocks, is basically an expensive source of gas. Chemically, it is identical to natural gas. As of late 1977, a number of planned plants were suspended or canceled due to lack of feedstock allocations by the government.

High-Btu Gas From Coal

Demonstrated technology (the Lurgi process) exists for converting coal to so-called pipeline quality gas. This gas is chemically equivalent to natural gas, although it generally has a slightly lower Btu content. Advanced (more economical) processes are under development.

GAS SUPPLY FORECAST

The Interim Model

Existing gas supply models have been analyzed for the Supply Program under RP436, and the study has been published as EPRI EA-201, A Comparative State-of-the-Art Assessment of Gas Supply Modeling. All of these models have deficiencies. Improved models are being developed for EPRI under RP944. In the interim, an in-house model has been used to forecast production in the lower 48 states and offshore production from earlier leases. The model takes into account the decline of production from existing wells, the output of new wells, and their decline. The production of associated or dissolved gas from oil wells is calculated from a simple equation using predicted oil production as the input variable.

The interim nonassociated gas model used predicts output as a function of gas production by category, vintaged price, and the cost of new gas reserves. It is a relatively simple simulation model and is believed to be basically conservative in its structure and parameters--that is, it is probably more likely to underestimate than to overestimate the nation's ability to produce natural gas. Major uncertainties are the size of new discoveries, the proportion of new well production that will qualify for new gas prices, and the extent to which the costs of factor inputs to gas exploration and development increase faster than general inflation. Given adequate profitability, the model assumes adequate funds for drilling.

It is appropriate to note that onshore drilling in recent years has been, in an economic sense, intensive rather than extensive. Much of the drilling has been in areas known to contain gas, but in quantities not economically producible under the existing price regulations. Higher prices make development of this gas feasible, but the additions per well are, as expected, less than for those resources historically recoverable under lower prices. The more important test will come as the result of new exploration, undertaken in response to higher prices, becomes known. Economically, this is the extensive margin.

In addition to contractor work on gas supply models, development of the in-house models is continuing, and more sophisticated in-house models will eventually be available. There is, of course, no guarantee that they will be better predictive models than those now in use.

Historical production and disposition of natural gas are shown in Table 1-5 on a so-called wet gas basis--that is, before the reduction in gas volume due to the

Table 1-5

U.S. PRODUCTION AND DISPOSITION OF NATURAL GAS, 1950-1975
(billion cubic feet)

	Production					Disposition					
	Gas Wells[a]	Oil Wells[a]	Total[a]	Repres-suring	Net	Losses and Waste[b]	Marketed Production	Field Use	Net Change in Under-ground Storage	Lost in Transmission and Unac-counted For	Net Marketed Production
1950	5,603	2876	8,479	1396	7,083	801	6,282	1187	54	175	4,864
1951	6,481	3207	9,689	1438	8,250	793	7,457	1441	138	192	5,684
1952	6,839	3433	10,272	1410	8,862	848	8,013	1483	176	203	6,149
1953	7,095	3550	10,645	1438	9,207	810	8,396	1471	158	240	6,527
1954	7,466	3518	10,984	1518	9,466	723	8,742	1456	102	215	6,967
1955	7,841	3877	11,719	1540	10,178	773	9,405	1507	67	246	7,582
1956	8,306	4066	12,372	1426	10,946	864	10,081	1420	136	212	8,311
1957	8,716	4189	12,906	1417	11,489	809	10,680	1479	191	205	8,803
1958	9,154	3992	13,146	1482	11,663	633	11,030	1604	83	283	9,059
1959	10,101	4127	14,229	1612	12,617	571	12,046	1737	118	223	9,966
1960	10,853	4234	15,087	1753	13,333	562	12,771	1779	131	274	10,585
1961	11,195	4265	15,460	1682	13,777	523	13,254	1881	145	234	10,992
1962	11,702	4336	16,308	1736	14,302	425	13,876	1993	86	285	11,511
1963	12,606	4367	16,973	1843	15,130	383	14,746	2081	130	364	12,169
1964	13,035	4405	17,440	1638	15,802	339	15,462	2082	128	302	12,948
1965	13,523	4439	17,963	1604	16,358	319	16,039	1909	118	318	13,693
1966	13,893	5139	19,033	1451	17,582	375	17,206	1772	68	401	14,693
1967	15,346	4904	20,251	1590	18,661	489	18,171	1925[b]	184	296	15,764
1968	16,539	4785	21,325	1486	19,838	516	19,322	2065[b]	95	325	16,836
1969	17,489	5189	22,679	1455	21,223	525	20,698	2212[b]	119	331	18,034
1970	18,594	5191	23,786	1376	22,410	489	21,920	2305[b]	398	227	18,989
1971	18,925	5162	24,088	1310	22,777	284	22,493	2296[b]	331	338	19,525
1972	19,042	4973	24,016	1236	22,779	248	22,531	2363[b]	135	328	19,704
1973	19,371	4695	24,067	1171	22,895	248	22,647	2412[b]	441	195	19,597
1974	18,669	4180	22,849	1079	21,769	169	21,600	2364[b]	83	288	18,863
1975	17,380	3723	21,103	860	20,242	133	20,108	2268	344	235	17,260

Source: U.S. Bureau of Mines, Natural Gas Annual, various issues.

Note: Production data include allowance for natural gas liquids content in the natural gas, and therefore differ from totals developed by AGA and used in other connections.

[a]Gross; includes gas (mostly residue gas) blown to the air but does not include direct waste on producing properties, except where data are available.

[b]Beginning in 1967, computed by AGA from "extraction loss" and from "lease and plant fuel" categories.

removal of natural gas liquids (heavier hydrocarbons) from the natural gas streams. Table 1-6 shows for the years 1975 and 1976 domestic supply and demand for natural gas and various adjustments, including the extraction loss. The tie between the two tables is the marketed production figure of 20,108 billion cubic feet for 1975 (Table 1-5). The projections in this report are on a so-called dry gas basis--after extraction loss. For 1975, the figure is 19,236 for marketed production, labeled "domestic production" in Table 1-6. In this report, the extracted natural gas liquids are shown as part of the petroleum liquids supply.

Our projections of conventional gas supply are shown in Table 1-7. Some of the supporting data are shown in subsequent tables. The projections are based on gas prices slightly above those in the National Energy Plan (NEP) currently under consideration. These prices are probably too low a projection of long-term prices. Total nonassociated onshore and pre-1977 offshore production were projected by the interim model using the prices shown. Total associated production is predicted from the appropriate crude oil production figures.

New offshore production has been predicted as follows. The "recent leases" row is derived from a study prepared by Arthur D. Little, Inc. (ADL) for the Department of Interior's Bureau of Land Management (4). The ADL projections assumed a price of $1.25 per thousand cubic feet. This price now appears low. For the years 1980 and 1985, one-half of the ADL projections have been used. This quite arbitrary adjustment has been made on the basis of apparent delays in the development of some of these leases due to environmental concerns. For 1990, the ADL figure has been used on the grounds that, by this time, the environmental delays should have been overcome. It is assumed that the basic ADL evaluation as to total quantity to be produced is correct, so that the adjustments made here affect only timing. The ADL figures do not go beyond 1990. To compensate for production foregone in the earlier years and further development of these leases, expected production is projected to peak in 1995, at the ADL 1985 peak value, and then decline.

Production from future (post-1976) offshore leases is a function of government policy and possible environmental delays. The figure used here is quite arbitrary. It is assumed that production from future leases will lag behind that projected, as above, for recent leases by five years through 1995. It will continue to grow thereafter as leasing continues. Accelerated offshore development could well produce larger figures.

Table 1-6

DOMESTIC SUPPLY AND DEMAND FOR NATURAL GAS

	1975		1976 (estimated)		
	Million Cubic Feet	Trillion Btu	Million Cubic Feet	Trillion Btu	Percent Change From 1975
Supply					
Marketed production[a]	20,108,661	22,022.2	19,800,000	21,752.0	-1.5
Transfers out, extraction loss[b]	-872,282	-2,381.8	-800,000	-2,353.0	-8.3
Domestic production[c, d]	(19,236,379)	(19,640.4)	(19,000,000)	(19,299.0)	(-1.2)
Exports	-72,675	-74.2	-70,000	-71.5	-3.7
Imports	953,008	973.0	970,000	990.4	+1.8
Stock change: withdrawals (+), additions (-)	-344,054	-351.3	+170,000	173.6	--
Losses and unaccounted for[e]	-235,065	-240.0	-270,000	-275.7	--
Total supply	19,537,593	19,947.9	19,800,000	20,215.8	+1.3
Demand by major consuming sectors					
Fuels and power					
Household and commercial[f]	7,432,417	7,588.5	7,950,000	8,117.0	+7.0
Other consumers[d,f]	(240,000)	(245.2)	(242,000)	(247.1)	--
Industrial[e]	7,781,394	7,994.8	7,595,000	7,754.5	-2.4
Transportation (pipeline fuel)	582,963	595.2	570,000	582.0	-2.2
Electricity generation, utilities	3,146,873	3,213.0	3,070,000	3,134.4	-2.4
Total	18,943,647	19,341.5	19,185,000	19,587.9	+1.3
Raw material (industrial)[g]					
Carbon black	26,246	26.8	25,000	25.5	-4.7
Other chemicals[h]	567,700	579.6	590,000	602.4	+3.9
Total	593,946	606.4	615,000	627.9	+3.5
Total demand	19,537,593	19,947.9	19,800,000	20,215.8	+1.3

[a]Marketed production represents gross withdrawals less gas used for repressuring and the quantities vented and flared. Btu value of production is for wet gas prior to extraction of natural gas liquids. Higher Btu values assigned to extraction loss represent the Btu value of natural gas liquids production for each year.

[b]Extraction loss from cycling plants represents offtake of natural gas for natural gas liquids as reported to the Bureau of Mines. The energy equivalent of extraction is based on annual outputs of natural gasoline and associated products at 110,000 Btu per gallon, annual outputs of liquid petroleum gases at 95,500 Btu per gallon, and annual outputs of ethane (since 1967) at 73,390 Btu per gallon. Beginning with 1973, the energy equivalent for plant condensate is computed at 129,000 Btu per gallon.

[c]Domestic production is the marketed production less the shrinkage resulting from the extraction of natural gas liquids.

[d]Figures in parentheses are not added into totals.

[e]Losses and unaccounted-for data were formerly included in the industrial sector.

[f]Includes deliveries to municipalities and public authorities for institutional heating, street lighting, and so on, formerly included in the industrial sector.

[g]Includes some fuel and power used by raw material industries.

[h]Estimated from partial data.

Table 1-7

ESTIMATED DOMESTIC GAS PRODUCTION AND PRICE--CONVENTIONAL SOURCES
(trillion cubic feet/year, dry gas basis[a])

	1975	1980	1985	1990	1995	2000
Lower 48 states[b]						
Nonassociated	15.4	15.7	15.9	14.5	11.4	8.2
Associated[c]	3.8	3.3	3.0	3.3	3.0	2.5
Subtotal A	19.2	19.0	18.9	17.8	14.4	10.7
New offshore						
Recent leases	--	0.7	1.2	2.0	2.5	1.5
Future leases	--	--	0.7	1.2	2.0	2.5
Subtotal B	19.2	19.7	20.8	21.0	18.9	14.7
Alaska onshore	--	--	0.7	0.7	1.0	1.5
Total domestic conventional	19.2	19.7	21.5	21.7	19.9	16.2
Average wellhead price for subtotal B gas (1976 $/ thousand cubic feet)	--	$1.02	$1.63	$1.76	$1.82	$1.85
Price of Alaskan gas at U.S. border (1976 $/ thousand cubic feet)	--	--	$3.45	$3.45	$3.45	$3.45

[a]1032 Btu per cubic foot.

[b]Includes production from offshore leases existing in 1975. Outer continental shelf production from such leases was estimated at 3.7 trillion cubic feet in 1975.

[c]Based on corresponding petroleum case.

The manner in which offshore production is predicted is one of the weaknesses of the present approach. More attention to this component is required.

Table 1-8 shows the expected contribution from supplemental sources of gas. Compared with the average prices, or even the implied marginal prices, of conventional natural gas, none of this gas appears economical to produce. However, in specific situations, some will be produced and used.

SNG is economical in certain circumstances for peak-shaving purposes. However, since it is based on petroleum feedstocks, it is unlikely that it will reach large volumes. The predicted values in the earlier years (Table 1-8) are a scaled-down version of AGA estimates, increasing to the AGA's value of 1.2 trillion cubic feet in the year 2000 (5). See Table 1-9 for AGA figures.

Imports from Canada have been declining for some years. However, there is now considerable optimism about future conventional gas production and also about the potential of low-pressure gas from shallow, low-porosity sands in southern Alberta. A recent Canadian Petroleum Association report shows that up to 35 trillion cubic feet may be discovered in Alberta and British Columbia in the next 25 years. In addition, resources in the shallow, low-porosity sands are estimated at some 400 trillion cubic feet. The Canadian National Energy Board, which must approve exports, is also taking a somewhat more favorable attitude toward exports (6). Up to 0.3 trillion cubic feet per year of additional Canadian gas may be available in 1980 in connection with the pipeline to bring Alaskan gas to the United States. This is not included in the projections.

Large supplies of natural gas from Mexico may begin entering U.S. markets before 1985. PEMEX, the Mexican government oil agency, is currently interested in developing a 750-mile, 48-inch trunk line extending from the Reforma oil fields to the U.S. border near Regnosa, Texas, at a cost of $1 billion. PEMEX would like to export approximately 0.7 trillion cubic feet per year of gas to the United States by 1981, but plans are stalled due to intergovernmental differences over price.

Optimistic estimates of Mexican gas supplies are based on greater than anticipated discoveries in the Reforma oil fields. The fields are now producing and flaring much more gas than expected. Gas-to-oil ratios from older wells have climbed from 1000 cubic feet per barrel when initially placed in production to 6000 to 7000:1. The Chiapas Tabasco fields are now producing six to seven times more associated gas than originally expected. Record production levels of some 1.5 trillion cubic

Table 1-8

PREDICTED CONTRIBUTION FROM SUPPLEMENTAL SOURCES OF GAS
(trillion cubic feet/year)

	1976	1980	1985	1990	1995	2000
SNG	0.2	0.5	0.8	1.0	1.0	1.2
Canadian imports	0.9	0.6	0.8	1.0	1.5	2.0
Mexican imports	--	--	1.0	1.5	2.0	2.0
LNG imports	0.1	0.8	1.5	2.0	2.5	3.0
Coal gasification*	--	--	0	0	0	0
New technologies	--	--	0.1	0.5	1.0	1.5
Total	1.2	1.9	4.2	6.0	8.0	9.7

Note: SNG and production from new technologies are assumed to be at $3.50 per thousand cubic feet. Canadian imports at the point of entry averaged $1.73 per thousand cubic feet in 1976. This price was increased to $2.13 per thousand cubic feet effective September 23, 1977. The price of Mexican gas is to be tied to the cost of No. 2 fuel oil imported into New York harbor. Currently, this would be $2.50-$2.80 per thousand cubic feet. LNG imports are likely to be in the $3-$4 range. The Federal Power Commission approved import of 0.17 trillion cubic feet per year, starting in 1980, to be sold in interstate commerce at $3.37 per thousand cubic feet (FPC Docket, Trunk-line LNG, CP 74-138 et al.).

*For current status, see Gas Supply Review, July-August 1977, pp. 8, 9.

Table 1-9

POTENTIAL CONTRIBUTION FROM SUPPLEMENTAL SOURCES OF GAS
(trillion cubic feet/year)

	1976	1980	1985	1990	1995	2000
SNG[a]	0.3	0.6	1.2	1.2	1.2	1.2
Alaskan gas						
Southern[b]	--	0.1	0.1	0.2	0.3	0.6
North Slope[c]	--	--	0.7	1.4	2.2	3.0
Canadian imports	1.0[g]	1.0	0.9	0.6	0.6	0.6
Mexican imports	--	0.4	0.7	1.0	1.0	1.0
LNG imports[d]	0.01	0.6	1.6	2.4	3.0	3.0
Coal gasification[e]	--	--	0.2	1.2	2.4	4.0
New technologies[f]	--	--	0.1	0.5	1.0	1.5
Total	1.3	2.7	5.5	8.5	11.7	14.9

Source: Gas Supply Review, November 1977, p. 8.

[a]Includes plants in operation, approved, and planned, as well as plants suspended and canceled due to lack of feedstock allocations by Federal Energy Administration.

[b]Southern Alaska includes onshore and offshore production of the Arctic Circle.

[c]Assumes a second major gas transportation system in operation by the early 1990s.

[d]Announced projects only through 1985.

[e]High-Btu gas only. Assumes loan guarantees for first few projects.

[f]Degasification of coal, gas from Devonian shale, gas from tight formations, gas from geopressure zones, gas from biomass, gas from in situ coal gasification, etc.

[g]Was shown as 0.9 in April 1977 issue of the Gas Supply Review.

feet are expected this year, a target previously anticipated for as late as 1982. Even with the export of gas to the United States, PEMEX will still have more gas than it can possibly export.

Negotiations between PEMEX and several U.S. interstate gas pipeline companies for the sale of gas have already begun. Both Florida Gas and Southern Natural Resources Company have signed letters of intent to purchase a combined total of 200 million cubic feet per day. Other major suppliers in the Southeast have also expressed interest. There is even the possibility of a 600-mile pipeline linking Texas with Arkansas to move Mexican gas into the interior of the United States.

The original problems to be overcome with Mexican gas were primarily financial and physical constraints; more recently, they have involved U.S. government approval of the price. Capital requirements to process the gas and to build the pipeline itself are crucial because of Mexico's difficulty in borrowing abroad as a result of International Monetary Fund restrictions. A possible solution lies in asking U.S. buyers to prepay for the gas. A second difficulty is a shortage of physical capacity to desulfurize the gas and reprocess it (because of its high liquids content) to avoid condensation in pipelines. This problem could also be alleviated with more funds to construct new facilities.

PEMEX feels that, in spite of these difficulties in the short run, gas from its fields may be potentially more important than Alaskan gas supplies and even less costly to produce. Current estimates indicate that the Reforma fields have probable reserves totaling 9.66 trillion cubic feet of gas and additional potential reserves of 20.65 trillion cubic feet. The cost of the gas was to be set at a price equivalent to the cost of No. 2 fuel oil imported into New York City--about \$2.50 to \$2.80 per thousand cubic feet. The price was to be adjusted quarterly to reflect foreign oil price changes. Although more expensive than domestic natural gas, the Mexican gas was projected to be less costly than imported LNG. Late in December 1977, plans were suspended because DOE refused to approve the proposed import price.

Projected LNG imports are a scaled-down version of the AGA potential import figures in the early years, rising to the AGA total in the year 2000.

No pipeline quality (high-Btu) gas from coal gasification plants is predicted in this case. A few facilities may be built, but the large capital investments required, combined with the much lower price of natural gas from conventional sources, make substantial production risky from an economic standpoint. Under different pricing policies, coal gasification could play a more significant role.

Production from new technologies includes production from Devonian shales in the East, tight gas formations in the West, methane from coal seams, and production from geopressure zones. Government officials have indicated a willingness to consider prices up to $3.50 per thousand cubic feet for such gas and to sponsor research and development on these resources. It is assumed that production from these sources will reach the levels projected by AGA.

The basic optimism here about projections from these sources compared with coal gasification hinges on the relatively smaller investment needed per unit of output for these new technologies. Table 1-9 shows AGA projections of production from supplemental sources. The extent to which this table has been utilized has been discussed in connection with Table 1-8. AGA is much more optimistic than the present study is about the production of high-Btu gas from coal.

Total gas availability from domestic conventional and unconventional, synthetic, and foreign sources is shown in Table 1-10.

A comparison of the projections of this study with figures from other sources is shown in Table 1-11.

Table 1-10

TOTAL GAS SUPPLY
(trillion cubic feet/year)

	1975	1980	1985	1990	1995	2000
Domestic conventional sources	19.2	19.7	21.5	21.7	19.9	16.2
Domestic unconventional sources	--	--	0.1	0.5	1.0	1.5
Synthetic natural gas	--	0.5	0.8	1.0	1.0	1.2
Subtotal	19.2	20.2	22.4	23.2	21.9	18.9
Imports	0.9	1.4	3.3	4.5	6.0	7.0
Total	20.1	21.6	25.7	27.7	27.9	25.9

Table 1-11

COMPARISONS OF PROJECTIONS OF TOTAL DOMESTIC GAS PRODUCTION AND PRICE

	1975	1977	1978	1980	1985	1990	1995	2000
Supply 77								
Trillion cubic feet	19.2	--	--	19.7	21.5	21.7	19.9	16.2
Wellhead price, dollars/ thousand cubic feet[a]	0.45	--	--	1.02	1.63	1.76	1.82	1.85
Delivered price, dollars/ thousand cubic feet[a]	1.29	--	--	2.13	2.83	3.06	3.22	3.35
National Energy Plan[b]								
Trillion cubic feet	--	--	18.8	17.8	17.2	--	--	--
Wellhead price, dollars/ thousand cubic feet[c]	--	--	0.77	0.96	1.70	--	--	--
Retail price, dollars/ thousand cubic feet[c]	--	--	2.14	2.37	3.15	--	--	--
Congressional Research Service[d] (trillion cubic feet)								
Lower 48 states onshore	--	--	--	13.1	11.0	8.8	--	--
Lower 48 states offshore	--	--	--	3.9	4.5	5.6	--	--
Alaska onshore	--	--	--	--	1.1	1.5	--	--
Alaska offshore	--	--	--	0.4	0.3	1.0	--	--
Domestic natural gas	--	18.6	--	17.4	16.9	16.9	--	--
Synthesis gas from oil	--	0.4	--	0.4	0.3	0.2	--	--
Synthesis gas from coal	--	--	--	--	0.5	1.5	--	--
Total gas supply	--	19.0	--	17.8	17.7	18.6	--	--

[a]1976 dollars, except 1975 figures.

[b]Institute of Gas Technology, Energy Topics, August 1, 1977, pp. 2-3.

[c]In 1977 dollars.

[d]Project Independence: U.S. and World Energy Outlook Through 1980, prepared by the Congressional Research Service, Library of Congress, and printed at the request of Henry M. Jackson, Chairman, Committee on Energy and Natural Resources; Ernest F. Hollings, Vice-Chairman, The National Ocean Policy Study; and John D. Dingell, Chairman, Subcommittee on Energy and Power, June 1977, Publication No. 95-31, pp. 25, 29.

The widespread difference of opinion as to future natural gas production is shown by the following quotation from Publication No. 95-31 of the Congressional Research Service, Library of Congress (June 1977), pp. 23-24.

> Companies were asked to provide production projections for "domestic dry gas to domestic use," a term used by the Bureau of Mines in its annual natural gas production statistics. It represents the dry natural gas after all the liquids have been taken out of the produced wet gas, and transmissions losses, storage, and exports are accounted for. Natural gas liquids were discussed in the previous section on petroleum liquids--crude oil and natural gas liquids. In order to calculate the volume of domestic natural gas which will be available to end users in the major sectors of the economy, one has to deduct from the domestic dry gas to domestic use figure used here, the volume used for pipeline fuel and lease and plant fuel. In 1974, this was about 2 trillion cubic feet.
>
> On the basis of the same basic assumptions listed in the previous section, the average projections derived from the responses of 12 leading oil and natural gas producing companies for the volume of dry natural gas production is as follows: 18.6 TCF in 1977; 17.4 TCF in 1980; 17.1 TCF in 1985; and 17.1 TCF by 1990.
>
> Production estimates varied among the 12 companies. The difference between the highest and the lowest estimate for 1985 was 8 trillion cubic feet, enough to meet 1976 demand for natural gas by the industrial sector. However, two-thirds of the companies estimated natural gas production by 1985 at between 15 and 18 TCF. The difference between the highest and lowest estimate for 1990 was 11.3 TCF, or equal to the 1976 demand for natural gas by the industrial sector and the electric utilities combined. It is difficult to explain such differences other than to argue that there are major differences in view--even among the oil and gas producers--about the effects of higher prices on finding rates. Of the 12 companies projecting 1990 natural gas production, 8 estimate natural gas production by 1990 at between 15 and 18 TCF. Hence, most of the companies project natural gas production to continue its current decline until the middle 1980's, followed by a period of stabilization or slow increase of production until 1990, the final year of our forecast.

Comment on Gas Supply

There is a strong tendency on the part of many people to regard resource depletion as the basic driving force behind increases in energy prices and conversely to regard increased energy prices as the mechanism by which energy supplies can be increased. There is an element of truth in this view, but only an element.

By far the major costs that an energy producer pays are not for the physical effort of finding and producing natural gas or other energy resources. Rather, they are transfer payments to other sectors of the economy. Some of these transfer payments, such as interest and dividends, are clearly necessary, although the required level may be uncertain. Other payments, such as lease bonuses, royalties, and taxes, are clearly transfer payments of an institutional nature. Indeed, legitimate questions have been raised as to the logic of large payments to foreign suppliers (e.g., imported crude oil) when the same prices paid to domestic producers would largely be recycled in the economy. Alternatively, if a larger portion of the price to the producer could be devoted to producing activities instead of transfer payments, large increases in production might be possible, even with depleting resources, without actual price increases.

Table 1-12 provides a concrete example. It shows projections by Foster Associates (in EPRI EA-411) of natural gas prices under one set of productivity assumptions. While the cost projections may or may not be correct, the breakdown of the costs into categories on a percentage basis is useful. Out of the total estimated 1985 cost of gas of $1.56 before liquids credits, less than 20% can reasonably be attributed to production items. Slightly over 20% represents rate of return on invested capital, a necessary item. Almost 60% represents pure transfer payments, including large tax payments. Clearly, what happens to these components--whether they increase or decrease and at what rates--is of much more significance to price projections than resource depletion is. Moreover, one must know (project) what these components are going to be before it is possible to say anything meaningful about the response of supply to price. Even a large increase in price will not bring about an increase in supply if the increase does not accrue to the physical activities that produce the output.

Consequential Statistics

Certain consequential statistics useful in understanding and judging the projections, such as gas wells drilled, reserves added, cumulative production, and year-end reserves, are shown below.

Figure 1-1 shows total gas well completions for the period 1946-1976, offshore gas well completions from 1959-1976, and projected onshore wells as forecast. The projected level of wells appears achievable. However, it must be remembered that wells differ greatly as to cost and productive characteristics. Consequently, wells are not an invariant measure of costs or output capability.

Table 1-12

COMPONENTS OF NATURAL GAS PRICE:
FOSTER ASSOCIATES PROJECTION,
HIGH-PRODUCTIVITY CASE
(cents/thousand cubic feet, 1975 dollars)

Cost Components	1985	1990	1995	2000
1. Successful well	11.48	12.28	12.89	13.49
2. Recompletion and deeper drilling	0.46	0.49	0.52	0.54
3. Lease acquisition	12.95	14.11	14.81	15.51
4. Lease equipment and other production facilities	2.66	2.85	2.99	3.13
Subtotal	27.55	29.73	31.21	32.67
5. Dry hole	9.21	10.91	12.25	13.49
6. G&G expenses, etc.	4.36	4.67	4.90	5.13
7. Exploration overhead	1.25	1.48	1.60	1.72
Subtotal	14.82	17.06	18.75	20.34
8. Operating expenses	3.10	3.10	3.10	3.10
9. Regulatory expenses	0.24	0.26	0.28	0.30
10. Net liquid credit	(9.20)	(10.00)	(10.80)	(11.50)
11. Unit return on working capital	3.34	3.65	3.84	4.04
12. Unit return on investment	30.76	33.32	35.27	37.26
Subtotal	70.61	77.12	81.65	86.21
13. Royalty (16%)	24.96	27.20	28.80	30.40
14. State production tax (3.16% plus 2.5¢/thousand cubic feet)	7.43	7.87	8.19	8.50
15. Income tax	53.00	57.81	61.36	64.89
Total wellhead cost	156.00	170.00	180.00	190.00

Items	Total	Percent
1, 2, 4, 5, 6, 7, 8, 9	32.76	19.8
3, 13, 14, 15	98.34	59.5
11, 12	34.10	20.7
	165.20	100.0
Less 10	9.20	
	156.00	

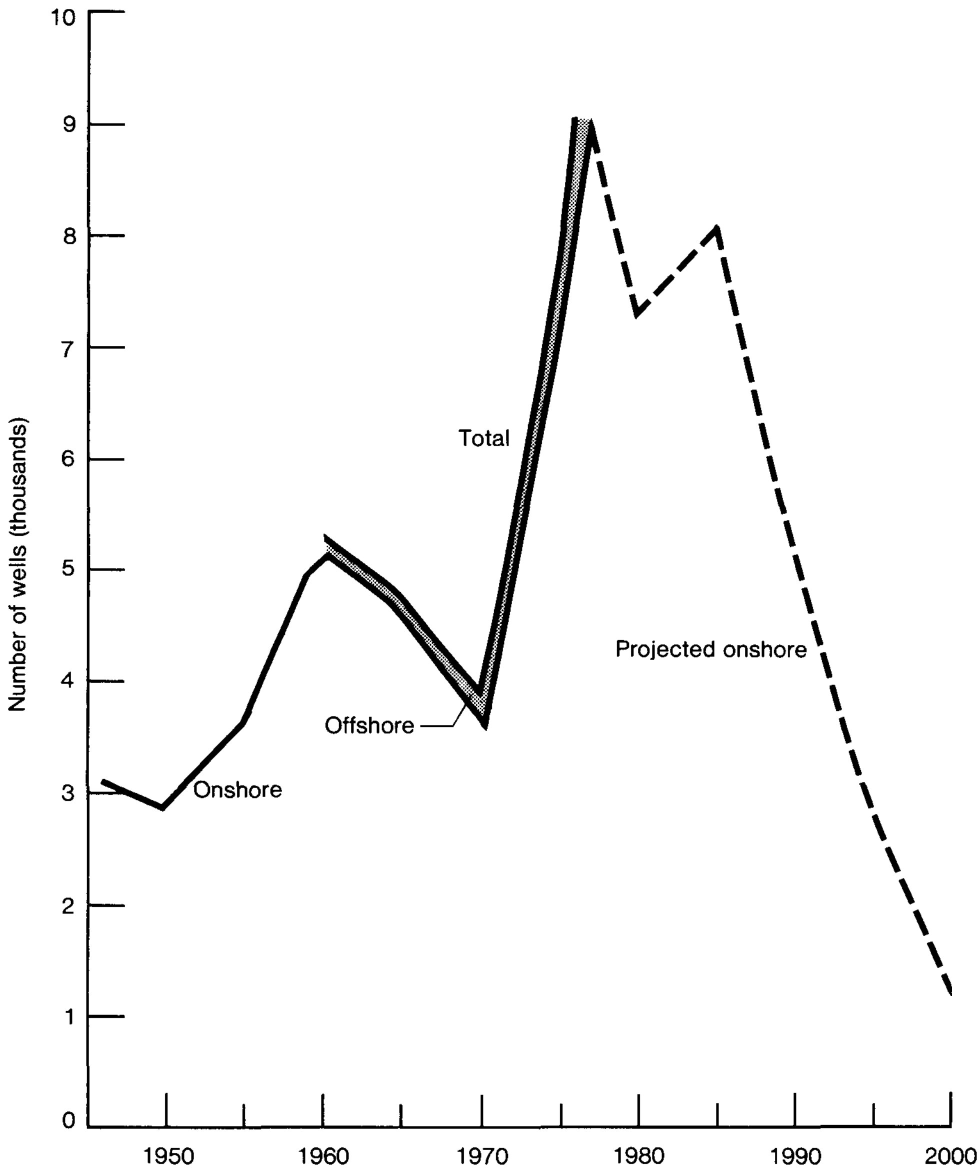


Figure 1-1. Natural Gas Well Completions

Cumulative natural gas production from 1975 is shown in Table 1-13. Table 1-14 shows the gross addition to proved reserves of Table 1-1 and the approximate projected gross reserve additions (including extensions and revisions but before deducting production) at five-year forecast intervals. The reserve additions must be considered as approximate, since there is not a fixed relationship between reserves and production, particularly with a good deal of in-fill drilling taking place.

GAS DELIVERY COSTS

The cost of transmission and distribution of natural gas to consumers has characteristically been a larger component than the wellhead price of the delivered cost of natural gas. Table 1-15 shows the historical figures. However, this delivery component varies greatly with the proximity of the consumer to the source of gas, customer class, and other factors, so that national average values are of limited value for analytic purposes.

Nevertheless, national averages are regularly compiled and used for some purposes. Projections of transmission and distribution costs vary widely, as shown in Table 1-16.

A number of factors will tend to increase the real cost of gas transmission and distribution. Fuel costs for pumping will go up. Foster Associates, in EPRI EA-411, Fuel and Energy Price Forecasts, estimates this increase at about $0.10 per thousand cubic feet in 1985 and $0.20 in the year 2000. Some pipelines will be operating at less than capacity, thus increasing fixed unit costs. Some new pipeline construction will be required at greater than imbedded costs, since not all new gas discoveries will be convenient to existing lines. Maintenance on existing transmission lines will probably increase with age, and many distribution systems may require extensive maintenance or new investment. A further factor tending toward higher unit costs is the planned diversion of gas from electric utilities and large industrial consumers to residential and commercial consumers. Unit costs tend to be scale-sensitive.

Against these cost-increasing factors stand the small or zero transmission cost for imported LNG, as this source becomes more important, and the unknown geographic shifts in future production-consumption relationships.

Table 1-13

CUMULATIVE NATURAL GAS PRODUCTION BEYOND 1975--CONVENTIONAL SOURCES
(trillion cubic feet)

	1980	1985	1990	1995	2000
Lower 48 states					
Nonassociated	78	157	233	298	346
Associated	18	36	53	66	76
Subtotal	96	193	286	364	422
New offshore					
Recent leases	2	6	15	26	36
Future leases	--	2	6	15	26
Subtotal	2	8	21	41	62
Alaska onshore	--	2	5	10	16
Total	98	203	312	415	500

Table 1-14

INFERRED NATURAL GAS RESERVES AND RESERVE ADDITIONS
(trillion cubic feet)

	Year-End Reserves	Period	Reserve Additions	Production
1975	228	1975-1980	93	98
1980	223	1980-1985	121	105
1985	239	1985-1990	108	109
1990	238	1990-1995	80	103
1995	215	1995-2000	47	85
2000	177			

Table 1-15

GAS INDUSTRY AVERAGE PRICES: WELLHEAD AND BY CLASS OF SERVICE, 1950-1975

	Wellhead Price (cents/thousand cubic feet)	Delivered Prices (dollars/million Btu)				
		Residential	Commercial	Industrial	Other	Total
1950	6.5	0.85	0.65	0.21	0.20	0.46
1951	7.3	0.82	0.64	0.22	0.22	0.46
1952	7.8	0.84	0.65	0.23	0.21	0.47
1953	9.2	0.87	0.68	0.24	0.22	0.48
1954	10.1	0.89	0.70	0.25	0.25	0.50
1955	10.4	0.90	0.70	0.27	0.29	0.52
1956	10.8	0.91	0.72	0.28	0.29	0.53
1957	11.3	0.92	0.72	0.28	0.28	0.54
1958	11.9	0.94	0.75	0.30	0.29	0.57
1959	12.9	0.97	0.76	0.30	0.31	0.58
1960	14.0	1.00	0.79	0.33	0.33	0.60
1961	15.1	1.02	0.80	0.35	0.34	0.62
1962	15.5	1.02	0.80	0.35	0.34	0.63
1963	15.8	1.02	0.80	0.35	0.35	0.62
1964	15.4	1.01	0.78	0.35	0.36	0.62
1965	15.6	1.01	0.78	0.35	0.36	0.62
1966	15.7	1.00	0.78	0.35	0.36	0.61
1967	16.0	1.00	0.78	0.35	0.36	0.61
1968	16.4	1.00	0.77	0.35	0.36	0.61
1969	16.7	1.01	0.78	0.36	0.39	0.62
1970	17.1	1.06	0.81	0.38	0.41	0.64
1971	18.2	1.12	0.85	0.41	0.38	0.68
1972	18.6	1.19	0.91	0.45	0.41	0.73
1973	21.6	1.25	0.95	0.50	0.44	0.79
1974	30.4	1.42	1.11	0.66	0.60	0.95
1975	44.5	1.69	1.38	0.99	0.94	1.29

Source: American Gas Association, Gas Facts, 1975, pp. 110, 111.

Note: Wellhead prices are in cents per thousand cubic feet and delivered prices are in dollars per million Btu. Cents per thousand cubic feet can be converted to cents per million Btu by

Table 1-16

PROJECTIONS OF NATURAL GAS TRANSMISSION AND DISTRIBUTION COSTS
(dollars/thousand cubic feet)

	1975	1976	1980	1985	1990	1995	2000
Actual[a]	0.86	--	--	--	--	--	--
EA-433[b]	0.70	--	0.71	0.73	0.66	--	--
AGA[c]	--	1.06	1.06	1.06	1.06	--	--
IGT[d]	--	--	1.41	1.45	--	--	--
Supply 77	0. 6	--	1.06	1.20	1.30	1.40	1.50

[a]Based on Table 1-15 of this study.

[b]Based on work published in EPRI EA-433. Figures derived from the Gulf-SRI model, in 1975 dollars. Costs are costs of new capacity.

[c]American Gas Association, Energy Analysis, April 8, 1977, Table VIII, Gas Delivery Cost Calculation, p. 11. In 1976 dollars.

[d]Derived, as difference between average retail price and average wellhead price, from Institute of Gas Technology, Energy Topics, August 1, 1977, Table 1. In 1977 dollars.

As part of RP944 on domestic oil and gas supply and its implications for electricity demand, what is perhaps the best gas transmission model in existence has been developed. Its use will ensure more accurate estimates of proper regional gas transportation costs in future work.

This study's estimates are also shown in Table 1-16. They are based on the considerations enumerated above. However, the specific numbers are arbitrary. It should be noted again, however, that national average numbers are not considered particularly important. The regional and subregional numbers are more relevant to projecting gas prices and requirements.

NOTES AND REFERENCES

1. Porosity refers to the relative volume of void space (pores) in the reservoir rock. This determines the amount of oil which the reservoir rock can hold. Permeability refers to the degree of interconnection of the pores and thus the potential ability of the oil to move through the rock to the producing wells. Many other factors, particularly the driving force moving the oil and the nature of the oil, affect actual producing rates.

2. Independent Petroleum Association of America. United States Petroleum Statistics 1977, p. 4.

3. Institute of Gas Technology Highlights, July 18, 1977, p. 1.

4. Outer Continental Shelf Oil and Gas Production Volume: Their Impact on the Nation's Energy Balance to 1990. Prepared by Arthur D. Little, Inc. for U.S. Dept. of Interior, Bureau of Land Management. July 1976.

5. American Gas Association, April 6, 1977.

6. Oil Daily, September 29, 1977, p. 5; The Energy Daily, April 26, 1977, p. 1, and July 25, 1977, p. 6.

Section 2

PETROLEUM LIQUIDS SUPPLY

CRUDE OIL

Crude oil is produced from a wide variety of underground reservoirs. Each reservoir is unique in terms of the porosity and permeability of the reservoir rocks, the natural energy tending to force oil out of the reservoir, the type of geologic trap involved, and the chemical composition of the crude oil (i.e., many thousands of different hydrocarbons in one crude oil).

As pointed out in the discussion of natural gas resources, oil and gas may be a joint product in a given field, or a field may produce either gas or oil separately. Overall exploration and development can be directed toward either crude oil or natural gas.

Oil production differs from natural gas production in that from 80% to 85% of the gas in gas reservoirs is normally recovered, whereas on the average only about 33% of the oil in an oil reservoir is recovered through primary and secondary (primarily water-flood) production. Some oil fields may yield as high as 90% in primary and secondary production, whereas others yield as low as 10%. There is no physical bar to recovering, on average, much larger amounts of the oil originally in place. To do so will require a combination of higher prices and new technology. The development of better technology to recover more of the hundreds of billions of barrels of oil which would be left in place with primary and secondary production is a major challenge. The various advanced techniques used and proposed for additional recovery are generally referred to as tertiary techniques. Table 2-1 shows historical production and reserve levels.

NATURAL GAS LIQUIDS

The stream of gas coming from a well, whether an oil well or a natural gas well, is not generally pure methane. It contains varying amounts of heavier hydrocarbons. Some of these tend to liquefy naturally at the lower surface temperatures. Others can be extracted by compression and refrigeration of the gas. These hydrocarbons are referred to as natural gas liquids (NGL). Sometimes

Table 2-1

SUPPLY OF U.S. CRUDE OIL--HISTORICAL
(million bbl of 42 U.S. gal)

	Proved Reserves at Start of Year	Reserve Revisions, Extensions, and Discoveries During Year	Production During Year[a]	Proved Reserves at Year End	Net Change in Reserves During Year	Indicated Year's Supply of Year-End Proved Reserves
1947	20,873	2464	1850	21,487	614	11.6
1948	21,487	3795	2002	23,280	1792	11.6
1949	23,280	3187	1818	24,649	1369	13.6
1950	24,649	2562	1943	25,268	618	13.0
1951	25,268	4413	2214	27,468	2199	12.4
1952	27,468	2749	2256	27,960	492	12.4
1953	27,960	3296	2311	28,944	984	12.5
1954	28,944	2873	2257	29,560	615	13.1
1955	29,560	2870	2419	30,012	451	12.4
1956	30,012	2974	2551	30,434	422	11.9
1957	30,434	2424	2559	30,300	-134	11.8
1958	30,300	2608	2372	30,535	235	12.9
1959	30,535	3666	2483	31,719	1183	12.8
1960	37,719	2365	2471	31,613	-106	12.8
1961	31,613	2657	2512	31,758	145	12.6
1962	31,758	2180	2550	31,389	-369	12.3
1963	31,389	2174	2593	30,969	-419	11.9
1964	30,969	2664	2644	30,990	20	11.7
1965	30,990	3048	2686	31,352	361	11.7
1966	31,352	2963	2864	31,452	99	11.0
1967	31,452	2962	3037	31,376	-75	10.3
1968	31,376	2454	3124	30,707	-669	9.8
1969	30,707	2120	3195	29,631	-1075	9.3
1970	29,631	3088[d]	3319	29,401[b] 39,001[c]	-230[e]	8.9[b] 11.7[c]
1971	29,401[b] 39,001[c]	2317	3256	28,462[b] 38,062[c]	-938	8.7[b] 11.7[c]
1972	28,462[b] 38,062[c]	1557	3281	26,739[b] 36,339[c]	-1723	8.1[b] 11.1[c]
1973	26,739[b] 36,339[c]	2145	3185	25,699[b] 35,299[c]	-1039	8.1[b] 11.1[c]
1974	25,699[b] 35,299[c]	1993	3043	24,649[b] 34,249[c]	-1049	8.1[b] 11.3[c]

Source: American Petroleum Institute, Committee on Reserves and Productive Capacity.

[a]Production is the amount originally estimated and used by API in prior reserve reports.

[b]Figures exclude 9.6 billion barrels located in Prudhoe Bay, Alaska. Discovered in 1968, this oil was not available for production until the Alaskan pipeline was completed.

[c]Figures include 9.6 billion barrels located in Prudhoe Bay, Alaska.

[d]Figure excludes 9.6 billion barrels located in Prudhoe Bay, Alaska. When Prudhoe Bay is included, this figure is 12,688.

[e]Figure excludes 9.6 billion barrels located in Prudhoe Bay, Alaska. When Prudhoe Bay is included, this figure is +9369.

the portion recovered at the producing lease itself is referred to as lease condensate.

Natural gas which contains an appreciable portion of NGL is referred to as wet gas. After removal of the NGL, the gas is referred to as dry, which is the form normally encountered by the consumer. Natural gas liquids are normally classified as part of the petroleum liquids supply.

RESOURCES

Crude Oil

Estimates of domestic crude oil resources are shown in Table 2-2. Reserves are the working inventory from which the industry produces. Inferred resources are those resources whose existence is to be expected with considerable confidence on the basis of existing reserves--for instance, undrilled locations in a well-defined field. Beyond these two categories are reserves yet to be discovered. Of particular importance is the oil already discovered in known reservoirs, some of which can be recovered by tertiary recovery processes at current (or future higher) prices and with improved technologies.

Production estimates to the year 2000 herein are not resource-constrained.

Shale Oil

Shale oil is discussed at some length because readers are assumed to be less familiar with it than with crude oil or natural gas. The nation's oil shale resources are vast, but the rate and extent of their commercial development is highly uncertain.

Oil shale is a sedimentary rock--formed by consolidation of clay, mud, or silt--which contains an insoluble material known as kerogen. Detailed composition of kerogen is not known. It is believed to be a high-molecular-weight cyclic polymeric material. This organic material undergoes decomposition at about 900°F, yielding a low-gravity crude oil with high concentrations of sulfur and nitrogen.

The principal source of information on the extent and quality of oil shale resources has been the U.S. Geological Survey (USGS). Industry has, quite properly, been more concerned with those resources most amenable to near-term development than with total resource availability. Following a brief consideration of the resource base, the discussion here proceeds to consideration of the Green River

Table 2-2

COMPARISON OF CRUDE OIL RESOURCE ESTIMATES
(billion bbl)

	Original Oil Resources in Place	Ultimate Cumulative Recovery at 32%[e]	Remaining Recoverable Resources (12/31/75) and Range at 32% Recovery	Undiscovered Recoverable Resources at 32% Recovery
USGS Circ. 725 (1975)[a]	681-781-922	218-250-295	109-141-186	59-91-136
National Petroleum Council (1973)[b]	810	259	150	100
Exxon (1976)				
Base	744-878-1094	238-281-350	129-172-241	79-122-191
Current[c]	622-731-963	199-234-308	90-125-199	40-75-149
Mobil (1975)				
32% basis[d]	647-756-959	207-242-307	98-133-198	48-83-148
40% basis[d]	584-671-834	187-215-267	106	56
M. King Hubbert (1974)	666	213	104	54
National Academy of Sciences (1975)	809	259	150	100
Parent and Linden (Institute of Gas Technology, 1977)	828	265	156	106

Note: This table does not include natural gas liquids. Remaining recoverable natural gas liquids are roughly from 15 to 30 billion barrels. The values shown are derived, on the basis of a consistent set of assumptions, from values given by the authors. Different interpretations of the published estimates would affect these figures slightly.

[a]Based on " . . . a continuation of price-cost relationships and technological trends generally prevailing in the recent years prior to 1974. rice-cost relationships since 1974 were not taken into account because of the yet undetermined effect they may have on resource estimates." USGS Circ. 725, p. 1.

[b]This is an updating of the 1970-1971 AAPG-NPC study, Future Petroleum Provinces.

[c]Resources within reach of current economics and technology.

[d]Uncertainty as to recovery factors used by Mobil leads to the two sets of figures. The higher set assumes that a 32% recoverability was used by Mobil in estimating undiscovered resources. The lower set assumes that a 40% factor was used (thus reducing the oil originally in place implied).

[e]With adequate prices, technological progress, and time, ultimate recovery may reach 40-50%.

Formation deposits in Colorado, Utah, and Wyoming and then to consideration of those resources most attractive for near-term development. This is followed by further detail on the classification of the Green River Formation deposits and a note on ownership of shale oil resources.

Oil Shale Resource Base. A comprehensive estimation of oil shale resources is provided by USGS Circular 523, Organic-Rich Shale of the United States and World Land Areas, by Donald Duncan and Vernon Swanson (1965). The "order of magnitude of total resources" of shale oil shown by that report is 168 trillion barrels (1). Even this amount does not constitute the total resource base, since it does not include large amounts of marine shale in Alaska with oil content in the range of 5 to 10 gallons per ton. Net energy considerations may limit the use of lower-grade shales as an energy resource.

A National Petroleum Council (NPC) oil shale report provides a breakdown of oil shale resources by location and class (2).

- Class 1: Resources include only resources which would average 35 gallons per ton in deposits at least 30 feet thick in the more accessible and better-defined deposits.
- Class 2: Resources average about 28.5 gallons per ton in deposits at least 30 feet thick in the more accessible and better-defined deposits.
- Class 3: Resources are said to match Class 1 and Class 2 in richness (i.e., to average 30 gallons per ton) but to be less well defined and not as favorably located.
- Class 4: Resources are lower-grade resources ranging down to 15 gallons per ton.

The NPC report states: "It is generally believed that underground mining can recover 65% to 70% of the resources in place. While certain areas of the Green River shales may be susceptible to surface mining, it is assumed that essentially all the minable resources will be recovered by underground mining. To provide for barriers between mines and unforeseen contingencies, an average recovery of 60% of the resources appears reasonable." Table 2-3 shows the resources available in Classes 1 through 3 at 60% recovery, according to NPC. Class 4 resources, computed at 60% recovery, are also included in Table 2-3.

Ownership of Oil Shale Resources. A 1968 Department of the Interior oil shale report notes that "it is estimated that 72% of oil-shale lands containing nearly 80% of the shale oil are federally owned. Of the higher-grade resources, about

81% are in federal ownership" (3). The report also notes that much of the federal oil shale land is subject to private mining claims.

Table 2-3

SUMMARY OF OIL SHALE RESOURCES AT 60% RECOVERY,
GREEN RIVER FORMATION--COLORADO, UTAH, AND WYOMING
(billion bbl)

	Class 1	Class 2	Class 3	Class 4	Total
Piceance Basin (Colorado)	20	50	100	550	720
Uinta Basin (Colorado and Utah)	--	7	9	176	192
Wyoming	--	--	2	154	156
Total	20	57	111	880	1068

Source: National Petroleum Council, U.S. Energy Outlook, An Initial Appraisal by the Oil Shale Task Group, 1971-1985, 1972, p. 27.

Oil Shale Environmental Problems (4). Synthetic fuel production, whether from oil shale, coal, or tar sand, presents considerably greater potential for environmental damage than conventional oil and gas production do. Extraction is considerably more likely to cause problems, and the additional synthesis step creates difficulties.

The available evidence suggests that oil shale, tar sand, and coal all involve roughly the same sorts of problems. The main differences apparently relate to the mining phase. Each of the three materials has quite different characteristics that will affect their impacts. Coal, of course, comes in solid veins, while the shale oils and oil from tar sand form only a small portion of the raw material volume. High-quality oil shales contain about 30 gallons of bitumens per ton of rock--about 17% of the volume. Canadian tar sands contain about 17.5 gallons of recoverable oil per ton of sand.

Therefore, the direct extraction process for shale and tar sand involves considerably more material removal than coal mining does; this could, of course, be offset by the existence of considerably greater overburdens on strip-mined coal deposits. However, if strip mining is conducted in the West, this situation is unlikely to prevail. The situation for oil shales is aggravated by shale's expansion during the recovery process. The crushed oil-free shale occupies a 50% greater volume than the original rocks, and compaction techniques would still leave the volume about 12-13% greater.

Shale oil would involve some water and strip mine reclamation problems; however, the shale should provide greater support against subsidence than is available in coal mining. With presently available methods, the shale must be mined, crushed, and heated to remove the oil. A current major development thrust is toward in situ retorting. Explosives would fracture the rock so that retorting could occur without removing most of the rock. In either case, the final recovery system produces a heavy (API 20°-28°) crude and a very low-grade gas (80-100 Btu per cubic foot). (Natural gas runs over 1000 Btu per cubic foot.) Sulfur emission problems will arise with the retorting process, but control methods exist. Retorting also produces water that must be treated. The big waste, as noted, is the shale. Since in situ methods have not been extensively demonstrated, it is not clear whether they would ensure better containment of pollution than would other methods. They introduce problems of their own, especially in the shale case, in which explosions are contemplated.

The shale also contains water-soluble material, and care must be taken to avoid leaching. The Interior Department has argued that moistening and compacting will produce a rapid natural cementation that will limit such problems. However, it would still be necessary to capture runoff from rainstorms that activate the waste piles. A study by Glen D. Weaver, sponsored by the Conservation Foundation, suggests that these conclusions might not apply to spent shales from processes other than the one from which the values were derived (5). Other processes might produce more porous wastes and create more severe pollution problems. The Interior Department report similarly places a somewhat more optimistic interpretation on the prospects for revegetation than does Weaver. Clearly, it can be done, but only slowly and with great effort. In situ recovery would obviate many of these problems but might have undesirable environmental consequences, such as groundwater contamination or whatever difficulties a fracturing approach would have. Since the techniques have not been widely tested, this remains conjectural.

Both mining and processing will require water use (and perhaps involve extraction of groundwater). The exact net impact cannot be predicted, but it is conceivable that the needs of an extensive development would strain available supplies. This essentially means that marginal water costs may mount to extremely high levels.

Coal

Coal is a potentially important source of synthetic crude. Coal resources are discussed in the section on coal.

PETROLEUM LIQUIDS SUPPLY

Many of the general remarks about geologic uncertainty, policy uncertainty as to leasing, allowable prices, and environmental restrictions made in the section on natural gas supply also apply here. Similarly, there is uncertainty as to future costs, particularly drilling costs. These comments will not be repeated here.

Domestic Crude Oil

Under the administration's National Energy Plan, domestic wellhead prices for new crude oil (see discussion in the section on gas) are to rise to the 1977 average landed price of foreign oil by 1980. The average landed price of foreign oil in 1977 is now projected to be $13.50 per barrel. There is some uncertainty as to the exact pattern of the rise of new crude oil prices to the $13.50 price in the year 1980. The price of new crude oil is not scheduled to follow world crude oil prices in subsequent years, but is to be adjusted for domestic inflation rates. Just as with natural gas, there are, for price purposes, various categories and vintages of crude oil; consequently, the average price of domestic crude will approach $13.50 gradually.

Table 2-4 shows details of domestic petroleum supply in 1975 and 1976. Table 2-5 shows a projection of domestic liquids production. It is based on a model very similar to that described previously for nonassociated natural gas production. The fundamental assumption is that the provisions of the administration's National Energy Plan as currently stated will prevail for the rest of the century. Lower-tier crude oil is assumed to be priced at $5.25 per barrel for the rest of the century. Upper-tier crude oil is assumed to be priced at $11.28 per barrel for the remainder of the century. Exempt production, except for tertiary oil, is assumed to be priced the same as production from new wells. (This may be too low a price assumption.) In accord with federal policy, prices for new oil will rise

Table 2-4

DOMESTIC SUPPLY AND DEMAND FOR PETROLEUM, 1975-1976

	1975		1976 Estimated	
	Million bbl	Trillion Btu	Million bbl	Trillion Btu
Supply, crude oil				
Production	3056.8	17,729.3	2974.1	17,250.0
Exports	-2.1	-12.2	-1.0	-5.8
Imports	1498.2	8,689.6	1922.2	11,140.0
Stock withdrawals	-6.3	-36.5	-18.8	-109.0
Losses, transfers for use as fuel, and unaccounted for	-5.2	-30.1	16.4	94.6
Total	4541.4	26,340.1	4892.9	28,378.8
Refinery inputs				
Crude oil	4541.4	26,340.1	4892.9	28,378.8
Transfers in, natural gas liquids[a]	259.3	1,172.2	256.1	1,157.7
Other hydrocarbons	13.8	48.3	13.8	48.3
Total	4814.5	27,560.6	5162.8	29,584.8
Supply, refined products				
Refinery output	4814.5	27,560.6	5162.8	29,584.8
Unfinished oil reruns, net	12.7	74.0	6.9	40.2
Processing gain, net	167.8	--	179.9	--
Total	4995.0	27,634.6	5349.6	29,625.0
Exports[b]	-74.3	-424.4	-74.2	-423.8
Imports[b]	700.8	4,157.9	729.6	4,328.8
Stock change, including natural gas liquids	-53.0	-256.5	+14.4	+69.7
Transfers in, natural gas liquids[a,c]	336.7	1,209.6	332.6	1,195.3
Losses, gains, and unaccounted for	52.3	420.4	-2.3	142.5
Total	5957.5	32,741.6	6349.7	34,[illegible]

Demand by major consuming sectors				
Fuel and power				
Household and commercial	853.6	4,733.2	943.2	5,264.4
Industrial	614.5	3,575.6	665.6	3,883.1
Transportation[d]	3310.9	17,795.6	3453.4	18,569.2
Electricity generation, utilities	520.1	3,293.3	559.0	3,479.3
Other, not specified	16.4	98.3	11.9	72.0
Total	5315.5	29,442.0	5633.1	31,268.0
Raw material[e]				
Petrochemical feedstock offtake	340.6	1,434.2	404.0	1,729.1
Other nonfuel use	268.7	1,685.7	284.5	1,785.8
Total	609.3	3,119.9	688.5	3,514.9
Miscellaneous and unaccounted for	32.7	179.7	28.1	154.6
Total	5957.5	32,741.6	6349.7	34,937.5

Source: Division of Interfuels Studies, Office of Assistant Director, Fuels. Bureau of Mines, U.S. Department of the Interior.

[a]Btu values for natural gas liquids for each year shown are implicitly derived from weighted averages of major natural gas liquids, with natural gasoline and other products at 110,000 Btu per gallon, liquefied petroleum gases at 95,500 Btu per gallon, ethane at 73,390 Btu per gallon, and plant condensate at 129,000 Btu per gallon.

[b]Btu values for imported and exported refined products for 1975 are totals of the Btu values of the respective products imported and exported. The 1975 average Btu value is applied to 1976 estimates.

[c]Includes natural gas liquids other than those channeled into refinery input as follows: petrochemical feedstocks, direct uses for fuel and power, and other uses.

[d]Includes bunkers and military fuel uses.

[e]Includes some fuel and power use by raw materials industries.

Table 2-5

FORECAST OF PRODUCTION:
CRUDE OIL, NATURAL GAS LIQUIDS, SHALE OIL, AND OIL FROM COAL
(thousand bbl/day)

	1975	1980	1985	1990	1995	2000
Lower 48 base	8,362	7,030	4,950	3,680	2,400	1,490
New offshore						
Recent leases	--	300	1,300	2,200	2,000	1,000
Future leases	--	0	300	1,300	2,200	3,000
Tertiary production	--	30	500	1,000	1,200	1,500
Total lower 48	8,362	7,360	7,050	8,180	7,800	6,990
North Slope	0	1,520	2,000	2,500	3,000	3,000
Total crude oil	8,362	8,880	9,050	10,680	10,800	9,990
Natural gas liquids	1,663	1,700	1,900	1,900	1,800	1,500
Total domestic petroleum	10,025	10,580	10,950	12,580	12,600	11,490
Shale oil	--	--	100	300	600	1,000
Syncrude from coal	--	--	--	--	--	--
Total domestic liquids	10,025	10,580	11,050	12,880	13,200	12,490

gradually to the 1977 average price of imported crude oil by 1980. In 1976 dollars, this is assumed to be $13.50 per barrel. It is assumed that all prices will be allowed to rise with inflation so as to keep them constant in 1976 dollars.

The tertiary oil price is assumed to increase $0.50 every five years, starting with $13.50 in 1980, all in 1976 dollars. Table 2-6 shows the average price of crude oil for domestic production, excluding Alaskan North Slope production.

The Federal Energy Administration (FEA) recently adopted final regulations which treat Alaska's North Slope crude as imported crude under FEA's pricing and entitlements program. Refiner acquisition cost of imported crude is currently estimated to be $14.60 per barrel. The average wellhead price after transportation costs will be $7.00 to $7.50 per barrel.

Shale Oil Supply

Commercialization of oil shale has appeared imminent three times in the past: once about 1920, when it was believed the nation was running out of oil; shortly after World War II, when it appeared domestic oil resources would be inadequate to support substantial expansion; and, most recently, in the early 1970s.

In recent years, environmental concerns, policy and legal difficulties in leasing the federal lands which contain the best resources, and other problems have delayed oil shale development. Among the other problems is the growing realization that the scale-up of almost any new technology to commercial size involves obstacles, costs, and delays that make the first few installations very risky. Shale oil technology has seemed sufficiently well developed that it has not received much federal R&D support. Yet the lack of commercial demonstrations has made industry move slowly in making the billion dollar investments likely required for commercial production. Uncertainty about federal pricing policy for crude oil and shale has also retarded development.

Some progress appears to have been made in resolving the problems of oil shale production (6). Occidental Petroleum and Ashland Oil are aiming at 1983 startup of a $400 million retorting operation to yield 57,000 barrels per day. Preliminary estimates of costs are said to be in the $8-$11 per barrel range, including a 15% return on investment. This cost is probably for a heavy (API 20°-28°) crude rather than a more typical 36° crude and would require upgrading to be equivalent to an average crude.

Table 2-6

FORECAST: AVERAGE CRUDE OIL PRICE AT WELLHEAD
(1976 dollars/bbl)

	1975	1980	1985	1990	1995	2000
Lower 48						
Production*	8362	7030	5291	3680	2400	1490
Average price	7.67	9.49	10.54	10.93	11.21	11.35
Future offshore						
Production*	--	300	1600	3500	4200	4000
Average price	--	13.50	13.50	13.50	13.50	13.50
Tertiary						
Production*	--	30	500	1000	1200	1500
Average price	--	13.50	14.00	14.50	15.00	15.50
U.S., excluding North Slope						
Production*	8362	7360	7391	8180	7800	6990
Average price	7.67	9.67	11.41	12.47	13.03	13.47

*Production figures are given in thousands of barrels per day.

Standard Oil Company (Indiana) and Gulf Oil expect to move forward on their Rio Blanco oil shale project this year, in which their investment may already be around $100 million.

Superior Oil Company (Houston) is also considering a project which would produce oil shale with nacholite as an important by-product. From the nacholite, alumina, soda ash, and sodium bicarbonate would be produced.

In the energy-short environment that is likely to characterize the United States during the remainder of the century, a role for oil shale seems highly logical, although costs and quantities are quite uncertain. A production level of 100,000 barrels per day in 1985 and 1,000,000 barrels per day in the year 2000 is believed reasonable at prices delivered to refining centers equivalent to the delivered price of world crude oil. Some upgrading of the shale oil from that produced by retorting is involved.

Syncrude From Coal

Two main types of oil product are under consideration for production from coal. One is a product intended specifically for fuel use in stationary installations, particularly power plants. Solvent-refined coal is an example. (The product may be either solid or liquid.) Such production is not considered here as part of oil supply. Any coal used for this purpose is included as part of coal production.

Coal can also be converted to a substitute crude oil which can, of course, be further converted to various petroleum products. Interest in producing petroleum substitutes from coal does not appear to be high at present. The oil industry, the most logical commercializer of such processes, seems more interested in shale oil than in coal conversion. One of the advantages that coal has over shale is that perhaps four times as much oil may be produced from one ton of coal as from one ton of shale. However, at present, other factors appear to more than offset this advantage.

No crude oil equivalent production from coal is predicted herein.

The General Accounting Office (GAO) recently reported that DOE will not meet its goal of commercializing coal liquefaction by 1983 due to the demise of the Coalcon demonstration project (7). GAO further reported that it takes from eight to twelve years from project conception through successful demonstration. It seems unlikely that a successful demonstration will be completed in time for large-scale commercialization before the end of the century. However, it is possible that production might approach that projected for oil shale.

Oil Imports

The future price and availability of oil imports has been the subject of much speculation. In the long term, there is uncertainty about the magnitude of the world's oil resources, and in the short and intermediate terms about the extent to which the policies of exporting nations will limit U.S. access to foreign petroleum and further increase the cost of imported oil.

The subject of world energy resources and potential supply under four economic growth/energy-intensity scenarios to 1990 has been studied for the EPRI Supply Program by Mr. John Lichthblau, president of Petroleum Industry Research, Inc., and Dr. Helmut Frank of the University of Arizona. The four world scenarios, which include four U.S. consumption scenarios, project the following range of U.S. oil import requirements (Table 2-7).

Table 2-7

RANGE OF U.S. OIL IMPORT REQUIREMENTS, 1976-1990
(million bbl/day)

	Preliminary 1976	1980	1985	1990
Case A	7.3	10.9	12.0	14.5
Cases B and C	7.3	10.3	10.4	11.7
Case D	7.3	9.7	9.1	9.4

The study concludes that "in terms of purely physical resource constraints, none of these growth rates would be unsupportable, taking the world outside of the Communist area as a whole." They note, however, that the situation of individual exporters differs significantly in regard to resources and technical, economic, and political factors which may act to constrain availability.

Major exporting countries are likely to press for energy conservation in consuming countries and the development of alternative sources of energy, but given that major consuming nations are pursuing such policies (through price effects, regulation, and R&D), it seems unlikely that exporters will choose to run a significant risk of upsetting long-term world economic growth. The policy most consistent with what have been assumed to be the objectives of the exporting nations is to limit crude oil price increases to amounts required to offset inflation rates plus, perhaps, small amounts to reflect increased real costs.

In the long run, it is also possible that tanker and facility costs will increase somewhat from present levels. Projected refiner acquisition costs of foreign crude which include tanker and facility costs are shown in Table 2-8.

Our reading of the literature and understanding of the situation leads us to predict that the Case B, C, and D import requirements can be met with only very moderate increases in delivered costs to the United States, measured in constant dollars, through 1990.

The basic rationale runs as follows. Oil exporters, although of various political and economic persuasions, are as a group basically responsible members of the world community and look forward to an increased role in world affairs. While they may miscalculate, as all nations have at one time or another, they understand that a peaceful, prosperous world is conducive, if not essential, to the

Table 2-8

FORECAST: REFINER ACQUISITION COST OF IMPORTED CRUDE
(dollars/bbl)

	Actual Dollars	1976 Constant Dollars
1974	12.52	--
1975	13.93	--
1976	13.48	13.48
1977 (Jan.-June)	14.39	--
1980	--	14.00
1985	--	14.50
1990	--	15.00
1995	--	16.00
2000	--	17.00

realization of their long-term aspirations. The recent worldwide recession has shown that both high energy prices and too rapid a rate of increase in energy prices can create economic and potentially political instability.

The situation after 1990 is less clear, since there is less assurance of resource adequacy, or, more correctly, since resource costs may begin to play a larger role in world oil prices. To allow for this effect, the rate of increase of prices is doubled beyond 1990.

For the higher Case A imports, assuming that world oil requirements in total are higher, prices would begin to move upward somewhat more rapidly starting about 1985.

The analysis here rules out both permanent long-run political upheavals in the Middle East and the discovery of additional resources as prolific as those of the Middle East somewhere in the world. Both are possible.

Under proposed administration policy, a crude oil equalization tax will be imposed (in three steps) to bring the refiner acquisition cost of domestic crude oil to the world price. Thus, the refiner's cost for domestic and foreign crude will be the same, unless foreign crude oil prices rise too rapidly, in which case the tax may be changed. While it would be too much to expect this policy, if implemented, to prevail to the end of the century, it is assumed that even if domestic crude oil prices were decontrolled, they would not rise above the world level. Consequently, the refiner acquisition cost of crude and the product prices forecast here would not be changed, although the mix of imported and domestic oil would shift.

PETROLEUM PRODUCT PRICES

Prices for three major classes of refined products and their weighted averages are predicted below on a basis consistent with projected crude oil prices. These prices are subject to the limitation that the product mix may change. If so, some shift among prices might be expected without shifting the refining margin. However, over the long term, a shift in relative yields would be accompanied by a shift in refining technology and refining costs. Neither of these shifts is included in the price projections of Table 2-9.

CONSEQUENTIAL STATISTICS

Certain statistics that are either a consequence of a given forecast or of data at an intermediate stage are useful auxiliaries to a forecast. Cumulative production, which measures depletion of the resource whose true size is unknown, is one item of interest. Cumulative production is shown in Table 2-10, which may be compared with resource estimates in Tables 2-2 and 2-3.

Annual completions of productive wells are also of interest. An estimate of future completions of onshore oil wells is shown in Figure 2-1. Onshore wells have historically accounted for a very high percentage of all wells drilled. Of course, fewer wells with larger reserves or more wells with lower reserves per well could yield the same production. Costs might or might not be different.

Table 2-9

FORECAST: REFINED PRODUCT PRICES
(1976 dollars/bbl)

	1976	1980	1985	1990	1995	2000
Motor gasoline						
Refinery crude oil acquisition cost	10.89	14.00	14.50	15.00	16.00	17.00
Refining cost, transport, distribution, and taxes	13.76	13.95	14.10	14.25	14.40	14.55
Pump price						
\$/bbl	24.65	27.95	28.60	29.25	30.40	31.55
¢/gal	59	67	68	70	72	75
Distillate fuel oil						
Refinery crude oil acquisition cost	10.89	14.00	14.50	15.00	16.00	17.00
Refining cost, transport, distribution, and taxes	5.97	6.20	6.40	6.60	6.80	7.00
Residential heating						
\$/bbl	16.86	20.20	20.90	21.60	22.80	24.00
¢/gal	40	48	50	51	54	57
Residual fuel oil						
Refinery crude oil acquisition cost	10.89	14.00	14.50	15.00	16.00	17.00
Refining cost, transport, distribution, and taxes	0.88[a]	2.05	2.10	2.15	2.20	2.25
Retail[b]	11.77	16.05	16.60	17.15	18.20	19.25

[a]Residual fuel oil prices were depressed in 1976. The corresponding figure for the first quarter of 1977 was \$2.31.

[b]Includes utility sales as well as other classes; utilities paid about \$12 per barrel for fuel oil, including distillate, in 1976.

Table 2-10

CUMULATIVE 1975-2000 PRODUCTION:
DOMESTIC CRUDE OIL, NATURAL GAS LIQUIDS, SHALE OIL, AND OIL FROM COAL
(million bbl)

	1975-1980	1975-1985	1975-1990	1975-1995	1975-2000
Lower 48 base	14,045	24,976	32,851	38,399	41,949
New offshore					
Recent leases	273	1,733	4,927	8,760	11,497
Future leases	0	273	1,733	4,927	9,672
Tertiary	27	511	1,879	3,887	6,351
Total lower 48	14,345	27,493	41,390	55,973	69,469
North Slope	1,387	4,599	8,705	13,724	19,199
Total crude oil	15,732	32,092	50,095	69,697	88,668
Natural gas liquids	3,041	6,326	9,793	13,170	16,181
Total domestic petroleum	18,773	38,418	59,888	82,867	104,849
Shale oil	--	91	456	1,277	2,737
Syncrude from coal	--	--	--	--	--
Total domestic liquids	18,773	38,509	60,344	84,144	107,586

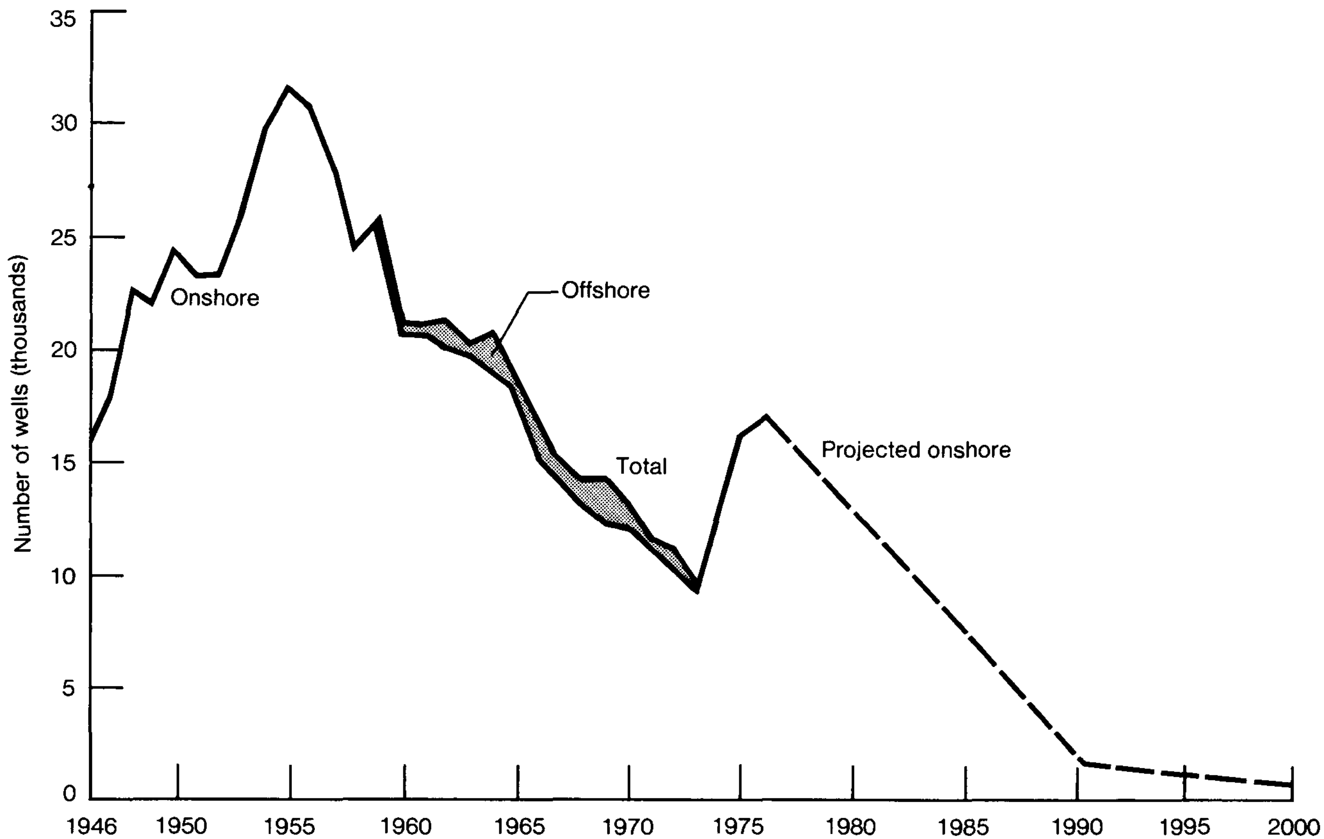


Figure 2-1. Oil Well Completions

NOTES AND REFERENCES

1. For purposes of comparison, oil consumption in the United States in 1976 was 6.3 billion barrels.

2. National Petroleum Council. U.S. Energy Outlook, An Initial Appraisal by the Oil Shale Task Group, 1971-1985. Washington, 1972.

3. U.S. Department of the Interior. Prospects for Oil Shale Development--Colorado, Utah, Wyoming. Washington, May 1968, p. 13.

4. Much of the material here comes from U.S. Department of the Interior, Final Environmental Statement for the Prototype Oil Shale Leasing Program, 6 volumes, Washington, 1973. In view of the existence of this massive report and the length of the present study, oil shale environmental problems are treated only briefly here. There is no intention to diminish the seriousness of the environmental consequences of large-scale oil shale development by this treatment. The environmental effects are such and the methods of alleviation so untested that the general attitude regarding oil shale development has been to proceed very slowly.

5. Glen D. Weaver. Environmental Hazards of Oil-Shale Development, Summary Report and Recommendations. Washington: Conservation Foundation, 1972, p. 20-1.

6. Chemical Week, July 13, 1977, pp. 18-19.

7. Coal Week, August 29, 1977.

Section 3

COAL SUPPLY

Future levels of coal production and price are a function of both the demand for coal (i.e., the schedule of amounts that the market would take at various prices through time) and the supply of coal (i.e., the quantity that would be produced at various prices through time). In theory and in practice, levels of production and price are jointly determined by the forces of supply and demand. However, in the case of commodities where long-run supply is quite elastic, as is judged to be the case for coal, future price levels can be approximated without precise analysis of the supply-demand interaction. This assumes, of course, that production and other variables change at reasonable rates.

While future coal prices are not highly sensitive to production levels, the manner in which the coal industry reaches a production level is important. For example, we estimate that high-sulfur coal production may reach 750 million tons by the year 2000. Our price forecasts assume production will reach an approximate range of 700 to 800 million tons in an orderly manner. If, though, high-sulfur coal production remained almost constant through the early 1990s and then spurted to 750 million tons by 2000, the price would be higher than we have forecast, since costs are higher in a very rapidly expanding industry (1).

The principal demand for coal is for use in the production of electric power. Other important demands are for industrial use, including metallurgical, and for export. Production for coal gasification, high and low Btu, is included, as is coal used for in situ gasification.

The Supply Program's initial coal supply forecasts are set out in the next section. Some of the more important factors influencing future coal supply are then discussed. Finally, the major uncertainties surrounding future coal supply are highlighted.

FUTURE COAL SUPPLY

Minemouth Prices

Regional price forecasts for high- and low-sulfur coal, FOB the mine, through the year 2000 are shown in Tables 3-1 and 3-2 and plotted along with historical prices in Figure 3-1. (Coal-producing regions are listed in Table 3-3.) These prices and price ranges are based on contract research performed for the Supply Program (2, 3), other reports, and our judgments concerning the future supply of coal.

Henceforth, the Supply Program coal supply forecasts will be more closely based on coal supply models. The Supply Program is currently in the process of getting two existing coal supply models up and running (4) and has just initiated a contract to develop a coal supply analysis system (RP1009). This system will combine the use of models and analyst insights.

Because of the uncertainties surrounding these forecasts, the general trends of the forecast may be more significant than the actual dollar figures. This should be particularly true for an individual utility, where a variety of factors may cause the absolute values to be different from those shown. It should be emphasized that these are long-term price forecasts and that no attempt has been made to forecast short-term variations from long-term trends.

The rates of change of the price forecasts are shown in Table 3-4. The rate change between actual 1975 and forecast 1985 prices is negative in Appalachia. This is not because we really expect prices to decline in Appalachia but because the 1975 price, as reported by the U.S. Bureau of Mines, includes metallurgical coal, which sells at a higher price than steam coal, and coal sold in the spot market. Coal not sold in the open market, which is primarily metallurgical coal, was not included, but this accounted for only 43% of the total amount of Appalachian coal shipped to coke and gas plants and exported to steel companies in 1975. If it is assumed that the metallurgical coal sold in the open market had the same price as that not sold in the open market, then it can be estimated that the average 1975 price of Appalachian steam coal was \$19.14. This price includes spot coal purchases whose price had been pushed up by short-term events, including the Arab oil embargo and the United Mine Workers' strike in late 1974.

Table 3-1

PRICE AND QUANTITY PROJECTIONS: HIGH-SULFUR COAL
(FOB mine, 1976 dollars)

	Appalachian		Interior		
	Price[a] ($/ton)	Quantity (million tons)	Price[b] ($/ton)	Quantity (million tons)	Total (million tons)
1985					
High	23.20		21.40		
Base	18.10	100	16.70	200	300
Low	17.20		15.90		
1990					
High	23.75		21.30		
Base	19.00	150	17.00	240	390
Low	17.70		15.80		
1995					
High	25.00		21.55		
Base	20.00	200	17.20	340	540
Low	18.20		15.70		
2000					
High	25.30		21.40		
Base	20.30	270	17.10	480	750
Low	18.30		15.45		

[a] 22.5×10^6 Btu/ton.

[b] 21.6×10^6 Btu/ton.

Table 3-2

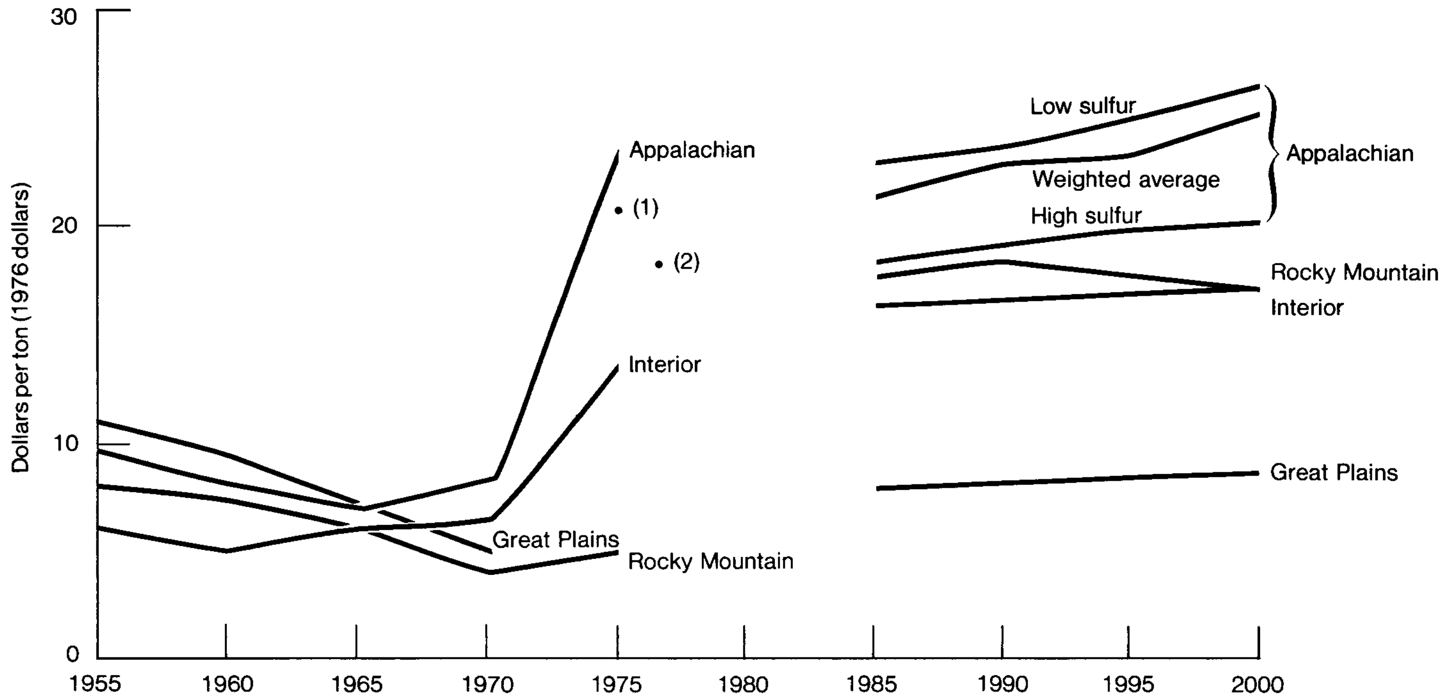
PRICE AND QUANTITY PROJECTIONS: LOW-SULFUR COAL
(FOB mine, 1976 dollars)

	Appalachian		Great Plains		Rocky Mountain		
	Price[a] (dollars/ton)	Quantity (million tons)	Price[b] (dollars/ton)	Quantity (million tons)	Price[c] (dollars/ton)	Quantity (million tons)	Total (million tons)
1985							
High	29.30		10.50		22.90		
Base	22.90	350	8.20	270	17.90	80	700
Low	21.80		7.80		17.00		
1990							
High	30.20		10.40		23.50		
Base	24.20	500	8.30	340	18.80	90	930
Low	22.50		7.70		17.50		
1995							
High	31.50		10.50		22.20		
Base	25.20	600	8.40	650	17.80	120	1370
Low	23.00		7.70		19.00		
2000							
High	32.80		10.90		21.65		
Base	26.30	670	8.70	1000	17.30	180	1850
Low	23.65		7.90		15.60		

[a] 22.5×10^6 Btu/ton.

[b] 16.1×10^6 Btu/ton.

[c] 21.0×10^6 Btu/ton.



(1) Estimated 1975 Appalachian steam coal
(2) Estimated 1977 Appalachian steam coal sold under contract

Figure 3-1. Regional Coal Prices, FOB Mine

Table 3-3

COAL-PRODUCING REGIONS

	1975 Production (thousand tons)
Appalachian	
Alabama	22,644
Georgia	74
Kentucky (eastern)	87,257
Maryland	2,606
Ohio	46,770
Pennsylvania	84,137
Tennessee	8,206
Virginia	35,510
West Virginia	109,283
	396,484
Interior	
Arkansas	488
Illinois	59,537
Indiana	25,124
Iowa	622
Kansas	479
Kentucky (western)	56,356
Missouri	5,638
Oklahoma	2,872
	151,116
Great Plains	
Montana	22,054
North Dakota	8,515
Wyoming	23,804
	54,373
Rocky Mountain	
Arizona	6,986
Colorado	8,219
New Mexico	8,785
Utah	6,961
Washington	3,743
	34,694
Other	11,771
Total U.S. production	648,438

Source: U.S. Department of the Interior, Mineral Industry Surveys: Coal, Bituminous and Lignite, Annual (1975), February 1977.

Table 3-4

FORECAST: ANNUAL GROWTH RATE OF FOB MINE PRICES
(1976 dollars)

	1975-1985 (%)	1985-2000 (%)
Appalachian		
High sulfur	-0.9[a]	0.79
Low sulfur		1.50
Interior (high sulfur)	2.00	0.20
Great Plains (low sulfur)	3.70	0.40
Rocky Mountain (low sulfur)[b]	--	-0.20

Note: 1976 data were not available at the time this table was prepared.

[a]Historical FOB mine price data not available by sulfur content. 1975 price excludes coal "not sold in the open market," most of which is metallurgical coal and is priced much higher than steam coal. It is not possible to exclude metallurgical coal sold in the open market.

[b]Not possible to show a meaningful 1975 price because data are withheld to avoid disclosing individual companies' confidential data.

Other indicators that the prices reported by the U.S. Bureau of Mines are high relative to contract steam coal prices are the "marker" contract steam coal prices reported by Coal Week. The weighted average mid-September 1977 Appalachian "marker" steam coal contract price, adjusted to a Btu content of 22.5 x 10^6 Btu/ton and to 1976 dollars, was $17.90.

Coal prices are expected to increase rather slowly after 1985 because, except in the Appalachian area, resource depletion is not expected to have much impact on coal prices through 2000. In addition, labor productivity is expected to increase during the latter part of this century. Prices could increase more rapidly if resource depletion proves to have a greater impact than anticipated and/or labor productivity does not improve or even declines.

It is also assumed that the industry will be able to grow in an orderly manner. If the industry is called upon to expand too rapidly, prices will be higher because it will have to bid increased quantities of labor and capital from other sectors of the economy. In addition, bottlenecks would quite likely develop.

Continuing uncertainties about future coal demand can also lead to a less orderly and higher-cost expansion of coal production.

Another important assumption is that the coal industry will remain competitive enough that producers will not be able to push prices up toward parity with oil and gas prices. In the East and the Midwest, almost all coal resources are privately owned. If a few coal companies ever gained control of enough of these resources to restrict entry and thereby allow prices to be raised to levels approaching those of oil and gas, it would seem reasonable to expect the government to initiate antitrust actions against the companies to restore competition.

In the West, where a substantial portion of the coal resources are controlled by the federal government and the Indian nations, it might be possible for access to coal lands to be restricted by parties immune to antitrust prosecution. Access to significant quantities of coal resources in all parts of the country might be denied for environmental reasons.

The ability of utilities and other large consumers to mine their own coal also acts to keep prices near cost. A recent survey by the FPC (now FERC) of electric utilities that presently control coal reserves (5) indicates that captive coal production will triple from 1975 to 1985, reaching up to 145.1 million tons. This planned captive coal production would be 18.8% of the projected 770 tons (FPC) of coal to be consumed by the electric utilities in 1985. The FPC report says it is reasonable to assume that some utilities which do not have coal operations at this time will acquire and develop coal reserves in the interim, or purchase coal mines which are already in operation. Based on this FPC survey, it appears that electric-utility-owned coal mines will be a significant factor in future markets. These, plus mines owned by other large producers, should work to keep prices close to costs.

Prices for low-sulfur Appalachian coal are expected to increase more rapidly than prices for high-sulfur coal from that area. Forecasting low-sulfur Appalachian coal prices is a very tenuous exercise, and it is almost impossible at this time to forecast what premium, if any, steam coal buyers will be willing to pay for low-sulfur Appalachian coal. Premium values in the steam coal market will be determined by a very uncertain combination of environmental regulations and compliance strategies, including the use of technologies that permit high-sulfur coal to be used in an environmentally acceptable manner.

Some forecasts show a price premium for low-sulfur coal equal to the cost of scrubbing emissions from high-sulfur coal. Others show a declining premium for low-sulfur coal on the assumption that all large coal-fired installations will be required to have scrubbers by some future date. While the present forecast assumes that all coal-fired facilities will be required to have scrubbers by the year 2000, it foresees the metallurgical coal market setting the prices for low-sulfur coal (6). It is forecast that the world demand for Appalachian metallurgical coal will drive the price of low-sulfur Appalachian coal above the price of high-sulfur coal even if it has little premium value in the steam coal markets. This very important interface between metallurgical and steam coal markets will be addressed in future work by the Supply Program.

National average FOB mine bituminous coal prices are shown in Table 3-5 and plotted in Figure 3-2 for 1955, 1960, and 1965 through 1975 in 1976 dollars, along with national average price forecasts. While national average FOB mine prices are often quoted and used in analyses, we feel they are not very meaningful and, even worse, can be misleading. This is so because coal markets are regional, not national, and because the key price in the marketplace is the delivered price, of which a very significant portion is transportation cost.

The price of coal to every individual power plant in the nation can be increasing, but the national average FOB mine price can be decreasing if consumption in relatively low-cost markets is increasing more rapidly than prices in higher-cost regions. For example, the national average FOB mine price is forecast to decline between 1975 and 2000, even though regional prices are all forecast to increase. This occurs because the portion of total coal production coming from the Great Plains region, where minemouth prices are relatively low (delivered prices may not be relatively low, though, because the mines are remote from many markets), is forecast to increase from a very small portion in 1975 to 30% by 2000.

Delivered Prices

The price of coal delivered to electric utilities and other large users via unit trains to the representative locations in each of the nine census regions is shown in Tables 3-6 and 3-7. The first shows prices in dollars per ton and the second in dollars per million Btu. (The assumed distances between producing and consuming regions and the assumed costs per ton-mile are shown in Table 3-8.) While these prices are indicative of what utilities will pay for coal, they may not be typical of those faced by an individual utility due to its actual distance from coal mines, its mix of coal purchases, the type of escalation provisions in its contracts, and other factors specific to its individual situation.

Table 3-5

NATIONAL AVERAGE COAL PRICES--OPEN MARKET
(FOB mine, 1976 dollars)

	Dollars/ton
Actual	
1955	7.29
1960	8.39
1965	7.38
1966	7.36
1967	7.26
1968	7.05
1969	7.18
1970	8.61
1971	9.23
1972	10.01
1973	10.72
1974	18.81
1975	20.03
Forecast	
1985	17.50
1990	18.50
1995	18.00
2000	17.55

Source: Actual figures from the Bureau of Mines (excluding coal not sold in the open market, which is primarily metallurgical coal). Forecast figures from the Supply Program.

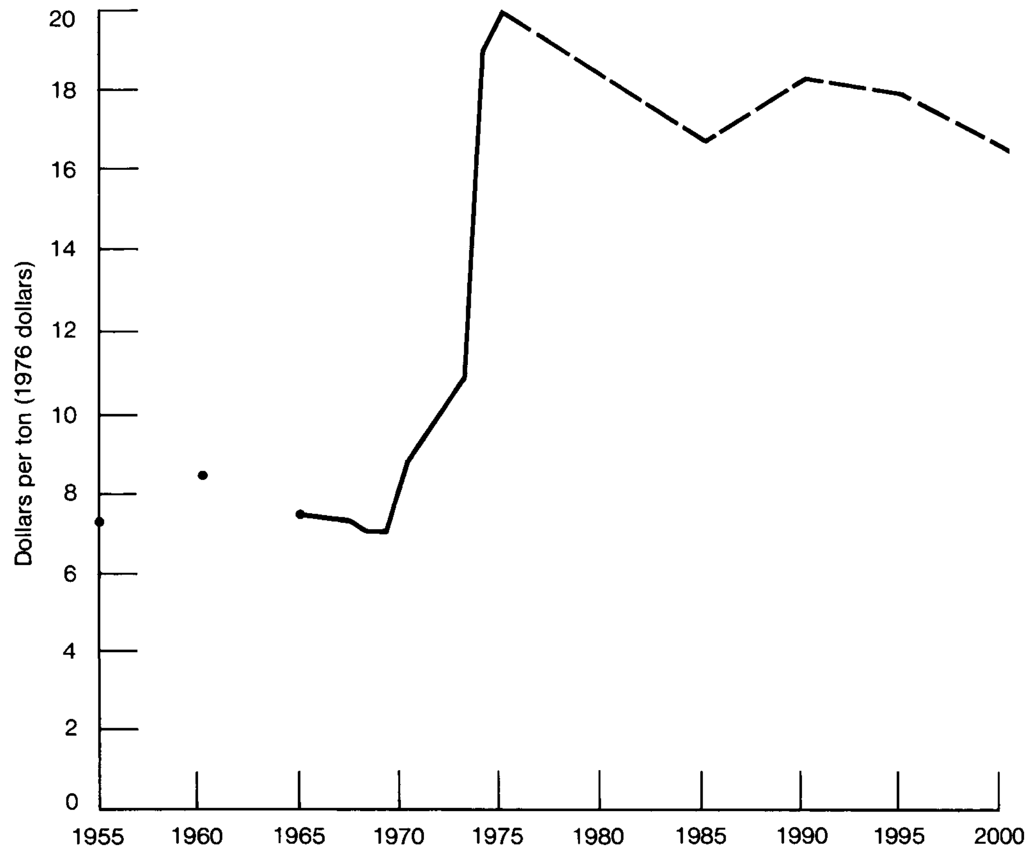


Figure 3-2. National Average Coal Price, FOB Mine (excluding coal not sold in open market, mainly metallurgical)

Table 3-6

FORECAST: PRICES OF DELIVERED COAL PER TON
(by unit train, 1976 dollars)

Destination (census regions)	1985 Low	1985 Expected	1985 High	2000 Low	2000 Expected	2000 High
New England						
Appalachian						
High sulfur	30.65	31.55	33.65	31.75	33.75	38.75
Low sulfur	35.25	36.35	42.75	37.10	39.75	46.25
Middle Atlantic						
Appalachian						
High sulfur	25.20	26.10	31.20	26.30	28.30	33.30
Low sulfur	29.80	30.90	37.30	31.65	34.30	40.80
Great Plains						
Low sulfur	31.30	31.70	34.00	31.40	32.20	34.40
South Atlantic						
Appalachian						
High sulfur	26.80	27.70	32.80	27.90	29.90	34.90
Low sulfur	31.40	32.50	38.90	33.25	35.90	42.40
Interior						
High sulfur	28.05	28.85	33.55	27.60	29.25	33.55
Great Plains						
Low sulfur	30.90	31.30	33.60	31.00	31.80	34.00
East North Central						
Interior						
High sulfur	24.95	25.75	30.45	24.50	26.15	30.45
Great Plains						
Low sulfur	19.60	20.00	22.30	19.70	20.50	22.70
East South Central						
Appalachian						
High sulfur	28.40	29.30	34.40	29.50	31.50	36.50
Low sulfur	33.00	34.10	40.50	34.85	37.50	44.00

Table 3-6 (continued)

Destination (census regions)	1985 Low	1985 Expected	1985 High	2000 Low	2000 Expected	2000 High
Interior						
High sulfur	21.20	22.00	26.60	20.75	22.40	26.70
Great Plains						
Low sulfur	21.30	21.70	24.00	21.40	22.20	24.40
West North Central						
Interior						
High sulfur	22.80	23.60	28.60	22.35	24.00	28.30
Great Plains						
Low sulfur	18.80	19.20	21.50	18.90	19.70	21.90
West South Central						
Great Plains						
Low sulfur	20.00	20.40	22.70	20.10	20.90	23.10
Local lignite*	--	--	--	--	--	--
Mountain						
Rocky Mountain						
Low sulfur	19.95	20.85	25.85	18.55	20.25	24.60
Great Plains						
Low sulfur	12.80	13.20	15.50	12.90	13.70	15.90
Pacific						
Rocky Mountain						
Low sulfur	27.20	28.10	33.10	25.80	27.50	31.85
Great Plains						
Low sulfur	23.80	24.20	26.50	23.90	24.70	26.90

*No forecast yet prepared.

Table 3-7

FORECAST: PRICES OF DELIVERED COAL PER MILLION Btu
(by unit train, 1976 dollars)

Destination (census regions)	1985			2000		
	Low	Expected	High	Low	Expected	High
New England						
Appalachian						
High sulfur	1.36	1.40	1.63	1.41	1.50	1.72
Low sulfur	1.57	1.62	1.90	1.65	1.77	2.06
Middle Atlantic						
Appalachian						
High sulfur	1.12	1.16	1.39	1.17	1.26	1.48
Low sulfur	1.32	1.37	1.66	1.41	1.52	1.81
Great Plains						
Low sulfur	1.94	1.97	2.11	1.95	2.00	2.14
South Atlantic						
Appalachian						
High sulfur	1.19	1.23	1.46	1.24	1.33	1.55
Low sulfur	1.40	1.44	1.73	1.48	1.60	1.88
Interior						
High sulfur	1.30	1.34	1.55	1.28	1.35	1.55
Great Plains						
Low sulfur	1.92	1.94	2.09	1.92	1.98	2.11
East North Central						
Interior						
High sulfur	1.16	1.19	1.41	1.13	1.21	1.41
Great Plains						
Low sulfur	1.22	1.24	1.38	1.22	1.27	1.41
East South Central						
Appalachian						
High sulfur	1.26	1.30	1.53	1.31	1.40	1.62
Low sulfur	1.47	1.52	1.80	1.55	1.67	1.96

Table 3-7 (continued)

Destination (census regions)	1985 Low	1985 Expected	1985 High	2000 Low	2000 Expected	2000 High
Interior						
High sulfur	0.98	1.02	1.23	0.96	1.04	1.24
Great Plains						
Low sulfur	1.32	1.35	1.49	1.33	1.38	1.52
West North Central						
Interior						
High sulfur	1.06	1.09	1.31	1.04	1.11	1.31
Great Plains						
Low sulfur	1.17	1.19	1.33	1.17	1.22	1.36
West South Central						
Great Plains						
Low sulfur	1.24	1.27	1.41	1.25	1.30	1.44
Local lignite*	--	--	--	--	--	--
Mountain						
Rocky Mountain						
Low sulfur	0.95	0.99	1.23	0.88	0.96	1.17
Great Plains						
Low sulfur	0.80	0.82	0.96	0.80	0.85	0.99
Pacific						
Rocky Mountain						
Low sulfur	1.30	1.34	1.58	1.30	1.31	1.52
Great Plains						
Low sulfur	1.48	1.50	1.65	1.48	1.52	1.66

*No forecast yet prepared.

Table 3-8

COAL TRANSPORTATION DATA

Destination (census regions)	Producing Regions: Appalachian	Interior	Great Plains	Rocky Mountain
New England				
Miles	840	--	2144	--
Cents/ton-mile	1.8	--	1.30	--
Dollars/ton	13.44	--	27.87	--
Middle Atlantic				
Miles	501	544	1805	--
Cents/ton-mile	1.60	1.60	1.30	--
Dollars/ton	8.02	8.86	23.45	--
South Atlantic				
Miles	600	759	1778	--
Cents/ton-mile	1.60	1.60	1.30	--
Dollars/ton	9.60	12.14	22.11	--
East South Central				
Miles	699	330	1351	--
Cents/ton-mile	1.60	1.60	1.00	--
Dollars/ton	11.18	5.28	12.51	--
West South Central				
Miles	--	688	1221	1046
Cents/ton-mile	--	1.60	1.00	1.00
Dollars/ton	--	11.01	12.21	10.46
East North Central				
Miles	311	567	1182	--
Cents/ton-mile	1.60	1.60	1.00	--
Dollars/ton	5.00	9.07	11.82	--
West North Central				
Miles	--	688	514	--
Cents/ton-mile	--	1.60	1.00	--
Dollars/ton	--	11.00	5.14	--
Rocky Mountain				
Miles	--	--	500	296
Cents/ton-mile	--	--	1.00	1.00
Dollars/ton	--	--	5.00	2.96
Pacific				
Miles	--	--	1600	1020
Cents/ton-mile	--	--	1.00	1.00
Dollars/ton	--	--	16.00	10.20

Source: For miles only: SRI International, Fuel and Energy Price Forecasts, EPRI EA-433, February 1977.

Production Levels

Future production levels are also shown in Tables 3-1 and 3-2. As is the case with the price forecasts, the general trends of these production levels are more significant than the actual tonnages shown. The forecasts are based on the results of contract research, other reports, and our own judgment. Because of existing and contemplated changes in federal regulations and policies designed to encourage interior and Appalachian coal production, it is quite possible that western coal production levels will be lower and interior and Appalachian coal production levels will be greater than shown in our forecasts. It is not appropriate to modify our forecasts, though, until these regulations and policies are better defined and there is some evidence of the viability of the policies for the long run. If government policies reduce western coal production, it should have a minimal impact on western minemouth coal prices, since resource depletion was not expected to have much impact on these prices. Increased interior and Appalachian production would cause coal prices to increase in these areas. How much they might increase would depend on which production sources were tapped and how fast coal production had to increase in these regions. Price effects from more rapid depletion by itself should not be great (see depletion schedules in Table 3-11). As indicated previously, prices, except for certain Appalachian coals, will not be strongly influenced by resource depletion. They are more a function of wage rates, productivity, and other factors. Thus, essentially the same prices may be expected for fairly substantial variations in output.

A recent National Electric Reliability Council (NERC) report (7) forecasts that the nation will require almost 1250 million tons of coal by 1985, including 824 million tons by the electric utility industry. This is 25% higher than the production levels shown in Tables 3-1 and 3-2. NERC is very doubtful, though, that the coal industry can produce 1250 million tons in 1985. The report says, "Increasing coal production to anywhere near 1300 million tons by 1986 is impossible unless drastic changes are made in several areas of federal law and in the present posture of the administration and the Congress regarding coal's use. Even with such changes, the doubling of coal production in 10 years will be an exceedingly difficult task."

Other Forecasts

Other recent coal price forecasts prepared for EPRI (8) are shown in Table 3-9. We are not aware at this time of any other coal price forecasts reaching to the year 2000.

Table 3-9

FORECAST: COAL PRICES--RUN OF MINE, FOB MINE
(1976 dollars/ton)

	1985			2000		
	Low	Expected	High	Low	Expected	High
Appalachian high sulfur						
Supply Program	17.25	18.10	23.20	18.30	20.30	25.30
SRI	--	15.38	--	--	17.50	--
Foster	--	21.40	--	--	25.80	--
ICF						
Northern	--	--	--	--	24.13	--
Central	--	--	--	--	21.58	--
Appalachian low sulfur						
Supply Program	21.80	22.90	29.30	23.65	26.30	32.80
SRI	--	21.80	--	--	23.42	--
Foster	--	25.70	--	--	30.60	--
ICF*						
Northern	--	--	--	--	21.12	--
Central	--	--	--	--	21.58	--
Interior high sulfur						
Supply Program	15.90	16.70	21.40	15.45	17.10	21.40
SRI	--	15.43	--	--	15.20	--
Foster	--	16.70	--	--	22.30	--
ICF	--	--	--	--	19.68	--
Great Plains low sulfur						
Supply Program	7.80	8.20	10.50	7.90	8.70	10.90
SRI	--	7.44	--	--	8.10	--
Foster	--	12.45	--	--	21.00	--
ICF*						
Eastern	--	--	--	--	8.66	--
Western	--	--	--	--	8.31	--

Rocky Mountain low sulfur						
Supply Program	17.00	17.90	22.90	15.60	17.30	21.65
SRI	--	15.67	--	--	14.80	--
Foster	--	22.40	--	--	25.90	--
ICF*	--	--	--	--	17.89	--

Source:

Supply Program: Forecasts prepared by EPRI's Supply Program staff, September 1977.

SRI: SRI International, Fuel and Energy Price Forecasts, EPRI EA-433, February 1977. Prices were stated in 1975 dollars. Increased 5.1% to reflect inflation rate 1975-1976.

Foster Associates: Foster Associates, Inc., Fuel and Energy Price Forecasts, EPRI EA-411, April 1977. Prices were stated in 1975 dollars. Increased 5.1% to reflect inflation rate 1975-1976.

ICF: ICF Incorporated, Alternative Coal Price Schedules, submitted to EPRI under SOA 76-326, November 1976 (high-demand, high-nuclear generation case, best available control technology). Revised per 12/17/76 letter to C. Rudasill from ICF. Also adjusted to heat contents used by Supply Program.

*Assuming use of best available control technology.

It is always difficult to compare forecasts, since they are scenarios in many ways. If the scenarios built into two different forecasts are not consistent, it is hard to make meaningful comparisons.

The coal production levels for the year 2000 that are used in the forecasts are shown below:

	Quadrillion Btu
Supply Program	51.4
SRI International	51.1
ICF Incorporated	54.0
Foster Associates, Inc.	30.0

The first three production levels are quite close in the year 2000. Foster based its analysis on the production levels shown in the Edison Electric Institute publication Economic Growth in the Future (McGraw-Hill Book Co., 1976). Foster felt that these forecasts were on the low side but that their use would not have a significant impact on its price.

The Supply Program, SRI, and ICF forecasts all assume that scrubbers will be required on all power plants by the year 2000. Foster was not explicit on this point.

In all but one case (interior, 1985), the Foster price forecasts are the highest. This is due primarily to an assumption that, in real terms (excluding inflation), wage rates will increase 3% annually and payments to the United Mine Workers' Welfare Fund will increase 7% annually between 1975 and 2000. We feel that these growth rates are high. At these rates, wages would double, and union benefit payments would increase 5.4 times (in real terms) between 1975 and 2000. Foster also added the premium due low-sulfur coal (because a scrubber is not required when using it) to the cost of low-sulfur coal. We feel this premium should be added to the cost of high-sulfur coal to arrive at the price of low-sulfur coal. The most one would be willing to pay for low-sulfur coal would be the cost of high-sulfur coal plus the cost of scrubbing high-sulfur coal emissions.

The ICF Appalachian, year-2000, high-sulfur coal prices are substantially higher than SRI's because ICF assumes more rapid resource depletion and constant mine productivity. For low-sulfur coal, the SRI year-2000 prices are higher than

ICF's. SRI argues that the metallurgical market will set the price of low-sulfur coal and that resource depletion will push prices up to the levels indicated. ICF did not consider the impact of the metallurgical market on coal prices, and assumed that the steam coal market would not pay a premium for low-sulfur coal, because it was assumed that all large coal-burning facilities would be required to have scrubbers.

ICF's interior, Great Plains, and Rocky Mountain coal prices for the year 2000 are somewhat higher than SRI's. ICF's assumptions about resource depletion and coal mine productivity appear to be more pessimistic than SRI's.

While there is not complete agreement among the Supply Program, SRI, and ICF coal price forecasts, they all tell basically the same story: Coal prices are expected to increase at only a very moderate rate during the rest of this century. It must be kept in mind, though, that all of these forecasts assume that the industry will develop in an orderly manner and that the industry will remain a competitive one. Also, as discussed elsewhere, many other uncertainties surround future coal prices.

RESOURCE DEPLETION CURVES

A useful starting point in the development of coal supply curves is the use of resource depletion curves, but this is only a starting point. The assumptions often made when developing resource depletion curves are listed below. The factors causing supply curves to differ from resource depletion curves are discussed subsequently.

1. Variable: resource quality (assuming that the highest-quality resources are mined first)
2. Constants
    a. Wages for a specific job function. Job functions and therefore average wages will vary as lower-quality resources are mined.
    b. Technology for a specific type of mine. Technology mix will vary as lower-quality resources are mined.
    c. Capital costs for a specific type of mine.
    d. Managerial skills.
    e. Type of labor force.
    f. Environmental costs.
    g. Profits and rents.

h. Socioeconomic costs.

i. How society perceives and reacts to the industry.

j. Government policy (closely related to the preceding point).

3. Other assumptions

   a. Perfect competition: price equaling marginal costs plus locational and quality premium.

   b. Perfect knowledge about the resource.

   c. No restraints on availability of the resource.

   d. Coal industry in a state of equilibrium.

   e. Growth in production about equal to growth of economy in general.

   f. The industry's decision-making process understood and constant.

4. Assumption fallacies (factors that can cause supply curves to differ from depletion curves)

   a. It is assumed that the resource location, size, quality, and so on are known. Actually, U.S. coal resources are not that well known.

   b. It is quite likely that wages for a specific job function will change--probably increase. Wage rates will be influenced by a variety of factors, including rate of production growth, cost of other energy sources, union power, coal industry marketing power, and the like.

   c. Coal mining technology may be improved; even more important, between now and 2000, better use may be made of existing technology.

   d. Changes in wages and technology may offset each other or lead to higher or lower labor costs per ton of coal mined.

   e. The cost of capital to the economy as a whole may change, and the ratio of capital costs for the coal industry to the cost of capital for the overall economy may also change. Cost of capital for the coal industry is a function of many factors, including the general economic condition of the nation, the growth rate of the industry, the perceived risks faced by the industry, a multitude of government policies, and so on.

   f. Quality of management may change. This is very important. Productivity of similar mines may vary quite substantially due to different quality of management. Types of companies in the industry are changing, causing change in the quality of management.

   g. The type of labor force is changing rapidly. Because the average age of miners is high, a large percentage retire each year and must be replaced with young miners who often have quite different value standards. If it is necessary to draw miners from outside the traditional labor pool, a new type of labor will be brought into the industry.

   h. Environmental costs may vary up or down for a variety of reasons, including the following:

      --New environmental impacts may be discovered.

      --Less expensive means may be found to cope with known or postulated environmental impacts.

--Society may choose to impose more stringent or less stringent environmental regulations.

--Environmental costs will probably increase more rapidly than production rates.

i. Factors not directly related to the cost of production may cause profits and rents to change.

j. Socioeconomic costs will probably increase instead of remaining constant.

k. Changes in how society perceives and reacts to the coal industry will have an important impact on government policy toward the coal industry.

l. The multitude of federal, state, and local government regulations affecting the coal industry can be expected to change over time.

m. The coal-producing industry may not be perfectly competitive, although most students of the subject feel that the industry is quite competitive. Other segments of the coal market may not be perfectly competitive, including coal transporters and buyers.

n. Producers have imperfect knowledge about coal resources. They may therefore unknowingly bypass relatively high-quality resources.

o. Producers may not be able to obtain access to relatively high-quality resources. Much of the eastern coal is controlled by coal companies, oil companies, and railroads. Much of the western coal land is controlled by the federal government, the Indian nations, and the railroads. It must be remembered, though, that by denying access to coal lands, the owner (or controller) is foregoing income. This fact will work to make coal available to potential producers.

p. The coal industry may rarely or never be in a state of equilibrium.

q. If coal production is to grow at a faster rate than the economy as a whole, it will have to bid factors of production away from other areas of the economy. To do so, it will have to increase its price for labor (wages), capital (interest rates), and so on.

r. The coal industry of the future is likely to be different from the industry of the past; an industry with strong growth reacts differently than a historically depressed industry does. In particular, learning and adaptation to new conditions will take place.

The Supply Program is taking these and other factors into consideration in its efforts to develop coal supply schedules. Some of the more important factors and uncertainties are discussed further in the following pages.

ROLE OF PRODUCTIVITY

A key factor in the future cost of mining coal is productivity. Productivity in the coal industry is usually measured as production per man-day, emphasizing the labor aspects of productivity. Productivity levels are a function of a variety of factors, including coal geology, technology used, relative cost of labor and capital, quality of the labor force, quality of mine management, financial health of the industry, government regulations, and others.

Both underground and surface mine productivity increased rather steadily between 1940 and the late 1960s, as shown in Table 3-10 and Figure 3-3. Then a combination of new federal health and safety regulations and labor unrest caused productivity of both underground and surface mines to decline.

It should be pointed out that the productivity of the mine crews at the face of underground mines declined only slightly after the late 1960s. The decline in productivity is reported to be due in large part to the fact that nonproducing workers had to be hired. Those include ventilation, maintenance, roof-bolting, and supervisory personnel.

Productivity between now and the end of the century will depend primarily on the quality of personnel (labor and management) and on the introduction of new technology. It is quite possible that the quality of the labor force, including management, will be the most important factor. It is common knowledge that the productivity of almost identical mines can vary greatly due to the quality of management and labor. Coal miners, particularly underground miners, tend to be skilled, independent workers. Under proper motivation they can, using current technology, produce large quantities of coal. On the other hand, if they are not motivated, or even worse, if they are dissatisfied, they can reduce their production in a myriad of ways. The Supply Program initiated a major study in the area of coal mine labor productivity in 1978 (RP1147).

New and improved technology will no doubt be developed and introduced between now and the year 2000. Because the coal miner is dealing with such variable geologic conditions, new technology cannot be introduced virtually overnight, as it can in a factory. Instead, it must be introduced through almost a system of trial and error.

Many analyses of future coal mining productivity treat the introduction of new coal mining technology as an independent variable. In reality, the rate at which new technology is developed and introduced is a function of other factors, such as cost of capital relative to the cost of labor, labor union acceptance, the cost of competing energy sources, the financial health of the companies in the industry, the level of government funding of R&D, and so on.

Table 3-10

PRODUCTIVITY IN BITUMINOUS COAL MINING INDUSTRY
(average tons/man-day)

	Underground	Strip	Total
1940	4.86	15.63	5.19
1941	4.83	15.59	5.20
1942	4.74	15.52	5.12
1943	4.89	15.15	5.38
1944	5.04	15.89	5.67
1945	5.04	15.46	5.78
1946	5.43	15.73	6.30
1947	5.49	15.93	6.42
1948	5.31	15.28	6.26
1949	5.42	15.33	6.43
1950	5.75	15.66	6.77
1951	6.08	16.02	7.04
1952	6.37	16.77	7.47
1953	7.01	17.62	8.17
1954	7.99	19.64	9.47
1955	8.28	21.12	9.84
1956	8.62	21.18	10.28
1957	8.91	21.64	10.59
1958	9.38	21.54	11.33
1959	10.08	22.65	12.22
1960	10.64	22.93	12.83
1961	11.41	25.00	13.87
1962	11.97	26.76	14.72
1963	12.78	28.69	15.83
1964	13.74	29.29	16.84
1965	14.00	31.98	17.52
1966	14.64	33.57	18.52
1967	15.07	35.17	19.17
1968	15.40	34.24	19.37
1969	15.61	35.71	19.90
1970	13.76	35.96	18.84
1971	12.03	35.69	18.02
1972	11.91	35.95	17.74
1973	11.66	36.30	17.58
1974	11.31	33.16	18.68
1975	9.54	26.69	14.74
1976	--	--	13.58

Source: U.S. Bureau of Mines, Minerals Yearbook, various years.

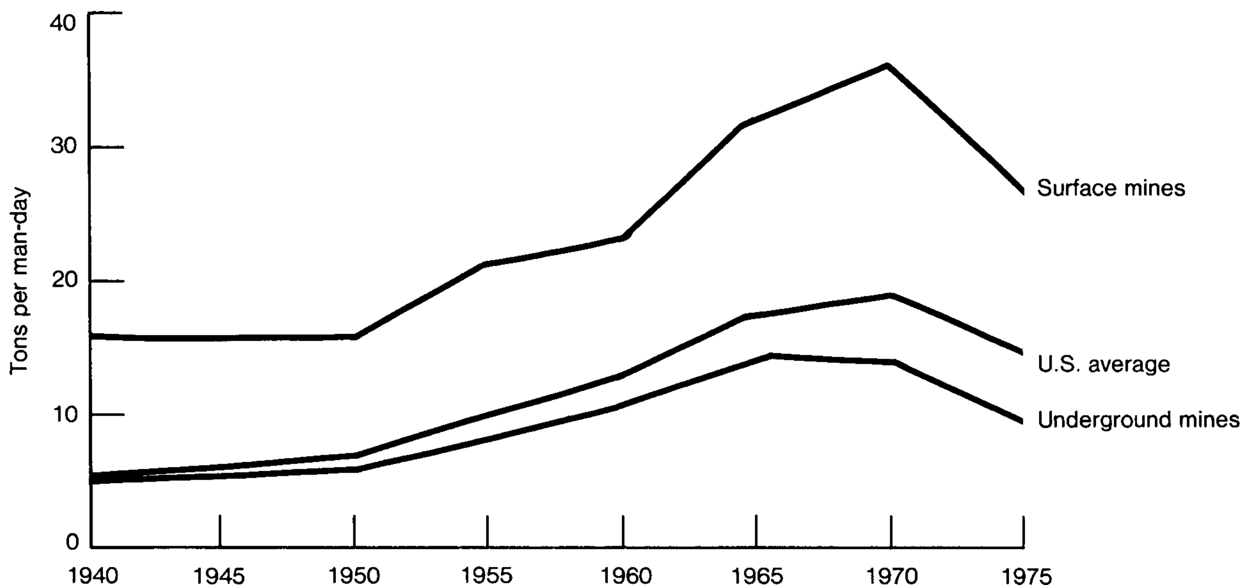


Figure 3-3. Coal Mine Productivity

APPARENT IMPACTS OF RESOURCE DEPLETION THROUGH THE YEAR 2000

Bituminous coal resource depletion schedules were developed by SRI International for four regions encompassing all major domestic producing regions (3). These schedules show the cumulative volumes of coal available at $1.00-a-ton incremental cost increases. The low end of the resource depletion schedules is shown in Table 3-11, along with cumulative production between 1975 and 2000 as calculated by the SRI National Energy Model (base case).

In the interior, Great Plains, and Rocky Mountain regions, cumulative production 1975-2000 is less than the amount of coal in the first increment, as shown in Table 3-12. Even if reserves committed to existing mines in 2000 are added to cumulative production through 2000, resource depletion appears to have little impact on mining costs in these areas through the century's end. It is assumed that production increases after 2000 would come from reserves not committed to existing mines.

While these are rather gross resource depletion schedules, and much more work must be done in this area, it does appear that resource depletion will have little impact on the price of coal produced in these three areas through 2000. Even if the coal resource quality declined at twice the rate indicated by these resource depletion schedules, it would only add $1.00 per ton to the cost of coal. Resource depletion will be an important factor in the Appalachian area. The SRI analysis indicates that resource depletion plus resources committed to existing mines will increase high-sulfur coal costs by $4.00 a ton between 1975 and 2000, while low-sulfur coal costs will be increased about $7.00.

Table 3-11

COAL RESOURCE DEPLETION SCHEDULES
(cumulative, billion tons)

Production Cost[a] (dollars/ton)	Appalachian High Sulfur	Appalachian Low Sulfur	Interior	Great Plains	Rocky Mountain
5.00	--	--	--	28.0	
6.00	--	--	--	56.1	
7.00	--	--	--	112.1	
8.00	1.1	0.5	--	--	4.4
9.00	2.1	1.1	6.0	--	8.9
10.00	3.2	1.8	11.9	--	13.3
11.00	4.2	2.2	29.3		
12.00	8.2	6.8			
13.00	14.9	15.4			
14.00	18.9	20.0			
15.00	22.8	24.5			
16.00	24.9	25.6			
17.00	28.8	30.2			
Cumulative production 1975-2000 (base case)	3.2	15.2	4.5	12.8	2.8
Reserves committed to existing mines in 2000[b]	2.7	6.7	4.8	10.0	1.8
	5.9	21.9	9.3	22.8	4.6

Source: SRI International, Fuel and Energy Price Forecasts, EPRI EA-433, February 1977.

[a]These are not SRI's price predictions. They do not include economic rents or user costs.

[b]Ten times production in 2000. Assumes new mines have a 20-year reserve.

Table 3-12

CUMULATIVE 1975-2000 PRODUCTION VERSUS COAL AVAILABLE IN LOWEST COST INCREMENT OF SRI RESOURCE DEPLETION CURVE
(billion tons)

	(1) 1975-2000 Production	(2) Coal Available in Lowest Cost Increment	(1)÷(2) (%)
Interior	4.5	6.0	75
Great Plains	12.8	28.0	46
Rocky Mountain	2.8	4.4	65

Note: Production was calculated by the SRI National Energy Model.

UNCERTAINTIES IN FORECASTS

A great amount of uncertainty surrounds coal supply forecasts. These uncertainties fall into four general categories: (1) uncertainties associated with factor inputs; (2) uncertainties about the coal resource; (3) uncertainties about the environmental impacts of coal production; and (4) uncertainties related to the forecasting methodologies.

Factor Input Uncertainties

Uncertainties related to factor inputs are probably the most significant in the case of coal supply forecasts. Factor inputs include, among others, labor, capital, and water.

As discussed above, much uncertainty surrounds the future availability, cost, and productivity of coal mine labor. Uncertainty also surrounds the cost and availability of capital for the coal industry. These uncertainties are not as great as those related to labor supply, though, and are due, in part, to the other uncertainties facing the industry.

Availability of water is an important uncertainty facing the western coal industry. Future water supply will be determined by a complex mixture of geology, engineering, law, and politics.

Uncertainties about future government policy contribute to the factor input uncertainties. The most important area of government policy affecting factor inputs is mine health and safety regulations. Other important areas include divestiture policy, tax policy, leasing policy, and government coal mining R&D.

Resource Uncertainties

Uncertainties pertaining to the nation's coal resources fall into two general categories: (1) size and quality; and (2) availability.

Size and quality refer to the geologic and chemical description of the resource. We know our coal resource is large; but because it is large and because the coal industry has been growing slowly, if at all, there has been little incentive to mount the effort required to obtain a more precise definition of our coal resources. Work in this area has increased substantially in the past few years, and hopefully we will soon have a better picture of our coal resources.

Our forecasts assume that, except in the case of certain Appalachian coals, resource depletion will have little impact on coal prices between now and 2000. It is possible that further exploration of our coal resources will show that resource depletion will exert greater upward pressures on mining costs.

Just because the resource is there, one cannot assume that it will be available to those wishing to open new mines. This uncertainty was discussed above, in the subsection describing FOB mine price forecasts.

Environmental Uncertainties

Environmental uncertainties fall into two general areas: (1) uncertainty about the environmental impacts of coal production; and (2) uncertainty about the regulatory response to environmental impacts.

As is the case in all areas of environmental impact assessment, we have much to learn. Industry plans, approved by government agencies, to increase coal production may be disrupted by newly discovered environmental impacts.

It may also be found that certain environmental impacts are not as great as now perceived. It should be noted that environmental uncertainties will probably have a greater impact on coal consumption than on the ability to expand coal production.

Environmental uncertainties are compounded by uncertainties as to the response by government and the public to real and imagined environmental impacts. This complex subject needs further analysis.

Forecasting Technique Uncertainties

Even if we had perfect certainty as to the supply of factor inputs, resource definition, and environmental impacts, we would still be faced with the uncertainties associated with all forecasting techniques. These uncertainties are the result of inadequate data, statistical measurement problems, model specification, and similar problems.

NOTES AND REFERENCES

1. It is assumed in this example that the rapid increase in production is not due to a significant price reduction (due to the introduction of a new technology, for example) with a resulting increase in demand.

2. Foster Associates, Inc. Fuel and Energy Price Forecasts. EPRI EA-411, April 1977.

3. SRI International. Fuel and Energy Price Forecasts, EPRI EA-433, February 1977.

4. These models are the coal supply model developed for the Potomac Electric Power Company by Charles River Associates and the National Coal Model developed for FEA by ICF Incorporated.

5. Federal Power Commission. Electric Utilities Captive Coal Operations. Staff report by the Bureau of Power, June 1977.

6. This is, of course, a simplified assumption, since not all low-sulfur Appalachian coal meets all the requirements of the metallurgical coal market and not all metallurgical coal is good steam coal.

7. National Electric Reliability Council. Fossil and Nuclear Fuel for Electric Utility Generation, Requirements and Constraints, 1977-1986. August 1977.

8. The SRI International and Foster Associates price forecasts were prepared for the Supply Program under RP759, and the ICF prices were prepared for the Planning Staff.

Section 4

NUCLEAR POWER: URANIUM SUPPLY

NUCLEAR POWER PROJECTIONS

The future of nuclear power is clouded by many uncertainties. Among these are future load growth, availability of capital, lead times for construction of new capacity relative to reasonable knowledge of load growth, construction costs, and questions about fuel supply.

Fuel supply questions resolve into questions concerning the rate at which the nation's uranium resources are likely to be found and converted to production capability, the price at which this supply will be available, the reprocessing of spent nuclear fuels, and the recycling of plutonium. There are also questions about the operation and maintenance of nuclear plants. Given the many uncertainties which utility executives must face in planning capacity expansion, and particularly nuclear expansion, it is natural that estimates of future installed nuclear capacity vary widely. Table 4-1 shows some of the more recent estimates of installed capacity. In Table 4-2, the low, base, and high estimates of nuclear capacity used in this analysis are shown. These are plotted in Figure 4-1.

The estimates are judgmental rather than derived from any model of electric utility expansion. It seems doubtful, in the present highly uncertain situation, that any model can yield much insight into the problem of future levels of nuclear capacity beyond what is already included in the judgments of various informed individuals and groups. For the base case, the 1976 ERDA (now DOE) low case has been adopted. It represents this report's judgment as to the approximate expected rate of growth of installed light water reactor (LWR) capacity. Given general agreement with that projection, there is no point in introducing a slightly different set of figures into an already confused literature. The DOE figures go only to the year 2000. Beyond 2000, it has been assumed for the next decade that installations will be at the rate of 20,000 megawatts per year. Another reason for using this base case is that James Schlesinger, secretary of DOE, has used the 380,000-megawatt figure for the year 2000 of this case in congressional testimony. It probably comes as close as any number to representing the administration's thinking as to what nuclear capacity may be.

Table 4-1

ESTIMATES OF U.S. INSTALLED NUCLEAR CAPACITY
(GW [e])

	Supply Program[a]	NERC	GAO[c]	NRC[d]	FEA	DOE	AIF[f]	Nye[g]	Fri[h]	Schlesinger[i]
1985	127	174[b]	112	151	102-111[e]	128	165			
1990	195				180-190[e]					
2000	380					300-400	510	350	300-330	380

Note: Unless otherwise identified, these estimates are taken from Nucleonics Week, May 26, 1977.

[a]Same as 1976 DOE low case.

[b]National Electric Reliability Council, Fossil and Nuclear Fuel, 1977-1986, August 1977.

[c]Computed from Nucleonics Week, July 28, 1977, pp. 6 and 7.

[d]From FPC, "Electric Power Supply and Demand, 1977-1986," May 16, 1977.

[e]Beginning of year.

[f]Atomic Industrial Forum.

[g]State Department.

[h]ERDA administrator.

[i]Now Secretary, Department of Energy; June 7, 1977, testimony.

Table 4-2

INSTALLED NUCLEAR CAPACITY--LWRs
(GW [e])

	Low	Base	High		Low	Base	High
1975	39	39	39	1990	185	195	251[b]
1980	55	60	68	2000	300[a]	380	501[b]
1985	115[a]	127	144[b]	2010	350	580	750

Note: Base case is this study's projection. It is the same as the 1976 DOE low case. Interim year figures without source are rough projections for completeness.

[a]Rough composite of GAO, FEA, and DOE (low) projections.

[b]S. M. Stoller Corp. report to FEA, "Assessment of U.S. Uranium Supply Outlook, Short and Intermediate Term," apparently May 1977. See Nucleonics Week, May 12, 1977, p. 15. Projection is said to be idealized and probably high for the year 2000.

Assuming that demand for electric power grows at rates which, while low by historical standards, are still substantial, it is likely that more nuclear capacity will be needed on the basis of economic criteria for installing new capacity than shown in the base case. To reflect this situation, a high projection of installed nuclear capacity is also shown. The 1985-2000 figures are based on a recent study by S. M. Stoller Corporation for the Federal Energy Administration. It may be noted that S. M. Stoller expressed reservations as to whether these high figures would indeed be achieved; in fact, even given that levels of electricity demand are realized which would require this level of nuclear capacity, there is no assurance that federal and state policies will be such as to allow the construction of nuclear capacity as needed. Nor is it at all clear that shortfalls in the required level of nuclear capacity will be made up by construction of coal- or oil-based capacity. There are also serious problems with the expansion of

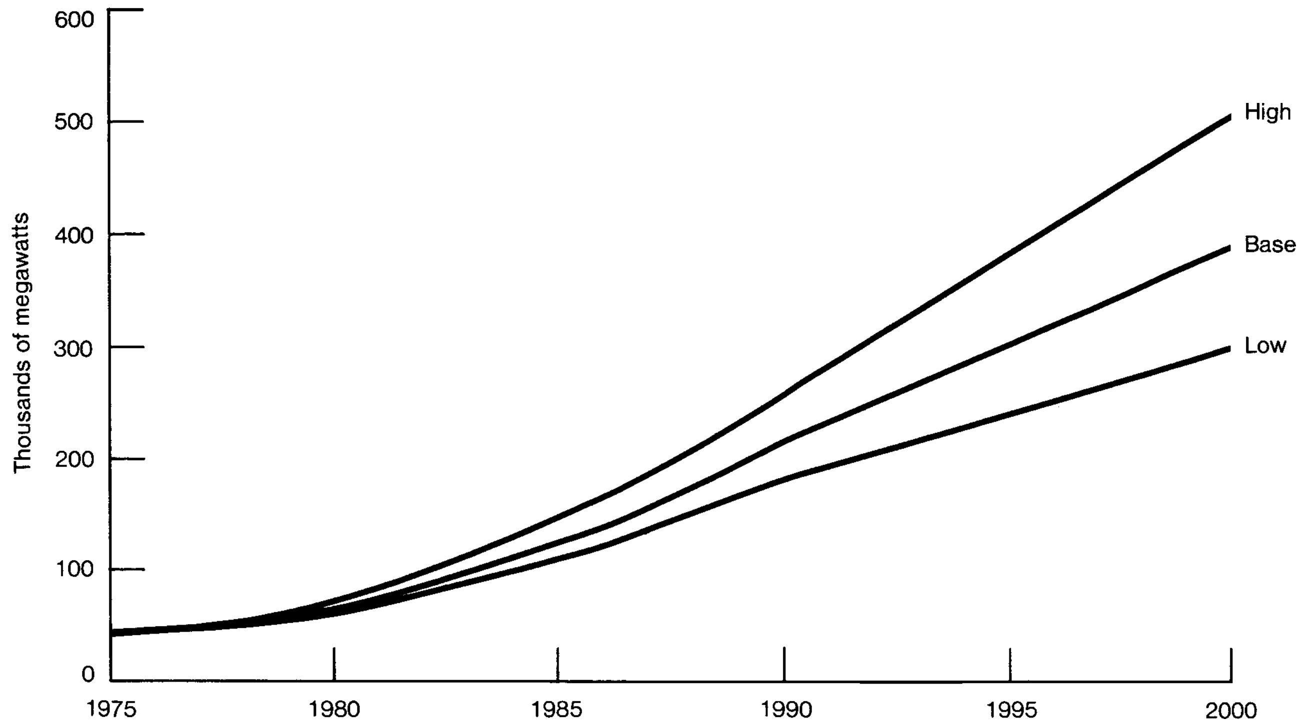


Figure 4-1. Projection of Installed Light Water Reactor Capacity

coal-fired capacity at a high rate, and the use of oil for new capacity is basically contrary to the thrust of national policy. It is perhaps at least as likely that there will be shortages of generating capacity as it is that the high projection will be achieved.

The extension of the high series from 2000 to 2010 is purely arbitrary and done simply for the purpose of making uranium calculations later in the report. It may be noted that the same absolute number of megawatts, neglecting any retirements, would be added in the 2000-2010 period as were added in the 1990-2000 period, thus representing an actual decline in the rate of nuclear growth.

The low-series projections for the 1985-2000 period are in a rough sense based on the GAO, FEA, and DOE low projections. The extension to the year 2010 is at a declining rate, consistent with the philosophy of a low case.

No consideration is given to the introduction of advanced converters before the year 2000. Some may be built, but it seems unlikely that enough will be built to substantially affect these projections. Similarly, no provision is made for commercialization of the fast breeder reactor before the year 2000. It is possible that a few fast breeder reactor plants will be on the line by that time, but unlikely that their number will be large enough to significantly impact the year-2000 figures.

URANIUM REQUIREMENTS

In the following tables, uranium requirements are shown on several different bases for each estimate of installed nuclear capacity in Table 4-2. Tables 4-3 through 4-5 show uranium requirements for the low, base, and high cases, respectively, at tails assays of 0.20%, 0.25%, and 0.30% (based on the assumption that there will be no recycling of uranium or plutonium). Tables 4-6, 4-7, and 4-8 show the same figures, on the assumption that there will be some reprocessing and recycling of uranium but not of plutonium. Tables 4-9, 4-10, and 4-11 show reprocessing cases with recycling of uranium and of some plutonium.

Table 4-12 presents summary uranium requirements for four cases. The high case assumes the high nuclear growth estimate of Table 4-2, diffusion plant tails assay of 0.30%, and no recycling of uranium or plutonium. This results in an annual uranium requirement of 118,000 tons in the year 2000 and cumulative production of 1,500,000 tons in the 1975-2000 period.

Table 4-3

URANIUM REQUIREMENTS: LOW NUCLEAR GROWTH CASE
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	17	61	19	66	21	73
1985	27	179	29	195	32	215
1990	39	348	42	379	46	417
1995	50	581	55	632	60	696
2000	51	836	55	911	61	1003

Note: Neither uranium nor plutonium is recycled.

*The enrichment plants were run at 0.25% tails assay, but producer's uranium deliveries to the government were on the basis of 0.20% tails assay. Uranium mill production was 11,600 short tons.

Table 4-4

URANIUM REQUIREMENTS: BASE NUCLEAR GROWTH CASE
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	18	63	20	68	22	75
1985	29	189	32	206	35	227
1990	43	374	46	407	51	448
1995	61	638	67	695	73	765
2000	75	986	82	1073	90	1181

Note: Neither uranium nor plutonium is recycled.

*See footnote on Table 4-3.

Table 4-5

URANIUM REQUIREMENTS: HIGH NUCLEAR GROWTH CASE
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	21	69	23	75	25	83
1985	35	220	38	240	42	264
1990	55	451	60	491	66	541
1995	80	796	87	870	96	958
2000	98	1251	107	1363	118	1501

Note: Neither uranium nor plutonium is recycled.

*See footnote on Table 4-3.

Table 4-6

URANIUM REQUIREMENTS: LOW NUCLEAR GROWTH CASE
WITH URANIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	17	61	19	66	21	73
1985	26	176	29	192	31	211
1990	35	328	38	357	42	393
1995	40	517	44	563	49	620
2000	41	723	44	786	49	867

Note: Uranium but not plutonium is recycled, starting in 1981.

*See footnote on Table 4-3.

Table 4-7

URANIUM REQUIREMENTS: BASE NUCLEAR GROWTH CASE
WITH URANIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	18	63	20	68	22	75
1985	28	187	31	203	34	224
1990	38	352	42	384	46	422
1995	50	568	55	618	60	681
2000	61	849	66	925	73	1019

Note: Uranium but not plutonium is recycled, starting in 1981.
*See footnote on Table 4-3.

Table 4-8

URANIUM REQUIREMENTS: HIGH NUCLEAR GROWTH CASE
WITH URANIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	21	69	23	75	25	83
1985	34	217	37	237	41	261
1990	49	425	54	463	59	509
1995	65	708	71	771	78	849
2000	80	1076	87	1172	96	1290

Note: Uranium but not plutonium is recycled, starting in 1981.
*See footnote on Table 4-3.

Table 4-9

URANIUM REQUIREMENTS: LOW NUCLEAR GROWTH CASE
WITH URANIUM AND PLUTONIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	17	60	18	66	20	72
1985	24	171	26	186	29	206
1990	28	304	31	333	35	370
1995	32	456	36	502	40	559
2000	31	614	34	679	39	758

Note: Both uranium and plutonium recycled, starting in 1981.

*See footnote on Table 4-3.

Table 4-10

URANIUM REQUIREMENTS: BASE NUCLEAR GROWTH CASE
WITH URANIUM AND PLUTONIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	18	62	19	68	21	75
1985	26	181	28	197	31	218
1990	31	327	34	358	38	397
1995	41	501	45	551	51	614
2000	48	725	54	801	60	894

Note: Both uranium and plutonium recycled, starting in 1981.

*See footnote on Table 4-3.

Table 4-11

URANIUM REQUIREMENTS: HIGH NUCLEAR GROWTH CASE
WITH URANIUM AND PLUTONIUM RECYCLED
(thousand tons U_3O_8)

	0.20% Tails		0.25% Tails		0.30% Tails	
	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative
1975*	9	0	--	--	--	--
1980	20	69	22	75	24	82
1985	31	210	34	230	38	254
1990	40	394	44	432	50	479
1995	53	625	58	688	66	766
2000	63	917	70	1013	79	1132

Note: Both uranium and plutonium recycled, starting in 1981.

*See footnote on Table 4-3.

Table 4-12

SELECTED URANIUM CONSUMPTION PROJECTIONS
(thousand tons U_3O_8)

	Annual Requirements				Cumulative Requirements			
	Low[a]	Base A[b]	Base B[c]	High[d]	Low[a]	Base A[b]	Base B[c]	High[d]
1975	9	9	9	9	0	0	0	0
1980	17	20	20	25	60	68	68	83
1985	24	31	32	42	171	203	206	264
1990	28	42	46	66	304	384	407	541
1995	32	55	67	96	456	618	695	958
2000	31	66	82	118	614	925	1073	1500

[a]Low case is based on low nuclear growth, 0.20% diffusion plant tails, and both uranium and plutonium recycled, starting in 1981. See Table 4-9.

[b]Base case A is base case nuclear growth, 0.25% tails, and with only uranium recycled, starting in 1981. See Table 4-7.

[c]Base case B is base case nuclear growth, 0.25% tails, with no uranium or plutonium recycled. See Table 4-4.

[d]High case is high nuclear growth, 0.30% tails, with no uranium or plutonium recycled. See Table 4-5.

Base case A of Table 4-12 uses the base nuclear power forecast of Table 4-2, 0.25% diffusion plant tails, and uranium recycling starting in 1981. Uranium requirements reach 66,000 tons in the year 2000, and cumulative requirements are 925,000 tons in the 1975-2000 period. Base case B differs from A only in that uranium recycling is not assumed.

The low case of Table 4-12 consists of low nuclear growth, 0.20% tails assay, and both plutonium and uranium recycling starting in 1981. In this case, only 31,000 tons of uranium are required in the year 2000, and cumulative production of 614,000 tons is required in the 1975-2000 period. Figures 4-2 and 4-3 show a plot of the annual and cumulative requirements of Table 4-12.

Tables 4-3 through 4-12 present the uranium requirements to support the low, base, and high nuclear growth forecasts under various assumptions regarding diffusion plant tails assays and reprocessing and recycling of nuclear fuels. In addition to uranium requirements for burnup and reactor loading, the uranium-producing industry must have found and largely developed sufficient reserves for some years into the future. Such a reserve inventory is highly desirable to provide assurance of uranium availability for future years. In addition, in order to make the investment necessary to mine and mill uranium, the producer needs assurance that there is sufficient ore available for a number of years of operation so that the investment can be recovered.

Although there is no fixed level of reserves which the producing industry must maintain, an eight-year forward reserve is generally accepted as a minimum. An eight-year forward reserve is defined as estimated requirements for the next eight years, including growth. Eight years is also reasonable in terms of the time from initial exploration to production. In the petroleum industry, a related concept is "years supply," which is simply reserves divided by current production. The uranium concept has the advantage of incorporating expected growth.

Tables 4-13 through 4-16 show the reserve additions on an eight-year forward reserve basis required for the low, base A, base B, and high uranium cases. Cumulative reserve additions from 1975 through 2000 are 761,000; 1,399,000; 1,686,000; and 2,426,000 tons, respectively.

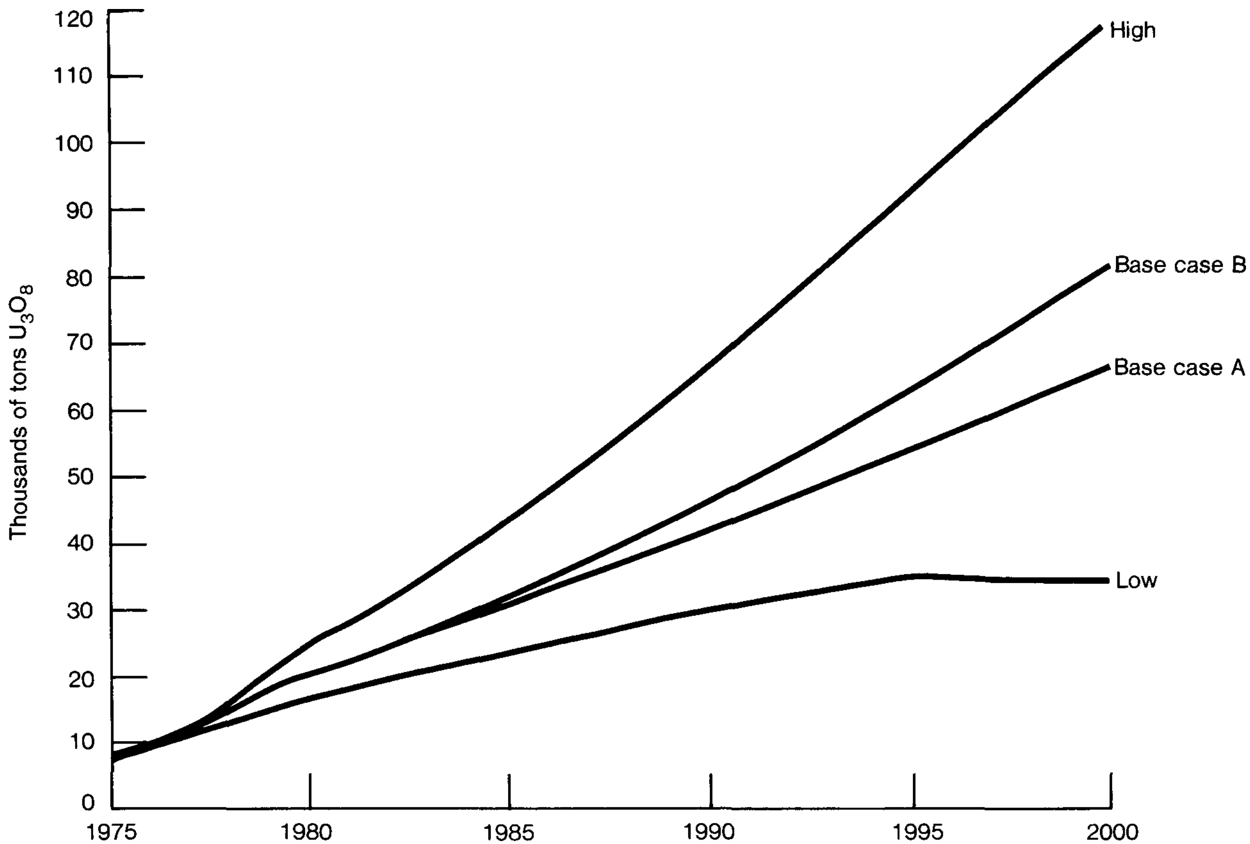


Figure 4-2. Annual Uranium Requirements for Reactor Loading

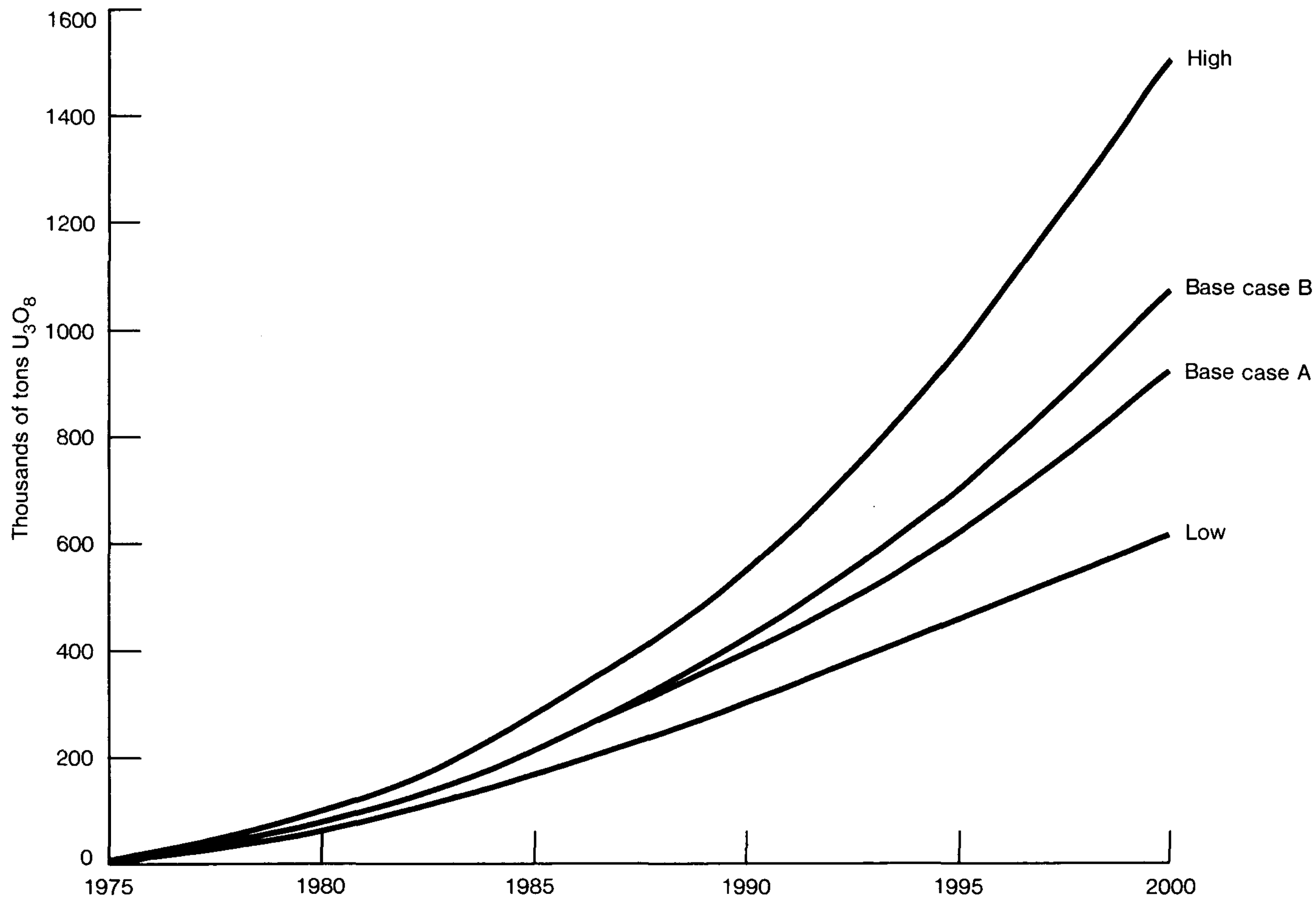


Figure 4-3. Cumulative Uranium Requirements From 1975

Table 4-13

RESERVE ADDITIONS TO SUPPORT REQUIREMENTS: LOW CASE
(thousand tons U_3O_8)

	Requirements		Eight-Year Forward Reserve	Required Cumulative Reserve Additions From 1975	Required Annual Reserve Additions
	Annual	Cumulative From 1975			
1975	9	0	122*	0	--
1980	17	60	187	125	27
1985	24	170	220	269	31
1990	28	304	248	430	32
1995	32	456	252	586	32
2000	31	614	269	761	37

Note: Case is from Table 4-12.

*The actual reserve of 640,000 tons was far in excess of the required eight-year forward reserve of 122,000 tons.

Table 4-14

RESERVE ADDITIONS TO SUPPORT REQUIREMENTS: BASE CASE A
(thousand tons U_3O_8)

	Requirements		Eight-Year Forward Reserve	Required Cumulative Reserve Additions From 1975	Required Annual Reserve Additions
	Annual	Cumulative From 1975			
1975	9	0	144*	0	--
1980	20	68	222	148	36
1985	31	203	299	360	47
1990	42	384	401	643	62
1995	55	618	507	983	73
2000	66	925	616	1399	90

Note: Case is from Table 4-12.

*The actual reserve of 640,000 tons was far in excess of the required eight-year forward reserve of 144,000 tons.

Table 4-15

RESERVE ADDITIONS TO SUPPORT REQUIREMENTS: BASE CASE B
(thousand tons U_3O_8)

	Requirements		Eight-Year Forward Reserve	Required Cumulative Reserve Additions From 1975	Required Annual Reserve Additions
	Annual	Cumulative From 1975			
1975	9	0	144*	--	--
1980	20	68	248	172	40
1985	32	206	366	428	57
1990	46	407	502	765	76
1995	67	695	629	1180	89
2000	82	1073	757	1686	107

Note: Case is from Table 4-12.

*The actual reserve of 640,000 tons was far in excess of the required eight-year forward reserve of 144,000 tons.

Table 4-16

RESERVE ADDITIONS TO SUPPORT REQUIREMENTS: HIGH CASE
(thousand tons U_3O_8)

	Requirements		Eight-Year Forward Reserve	Required Cumulative Reserve Additions From 1975	Required Annual Reserve Additions
	Annual	Cumulative From 1975			
1975	9	0	181*	--	--
1980	25	83	333	235	55
1985	42	264	508	591	83
1990	66	541	730	1090	109
1995	96	958	918	1696	129
2000	118	1501	1104	2426	158

Note: Case is from Table 4-12.

*The actual reserve of 640,000 tons was far in excess of the required eight-year forward reserve of 181,000 tons.

URANIUM RESOURCES

Questions have been raised as to the adequacy of uranium resources to meet the nation's uranium needs through the year 2000. Table 4-17 shows the DOE estimate of United States uranium resources for evaluated areas as of January 1, 1977. Table 4-18 shows an estimate for the total United States and includes estimates for the areas not yet evaluated by DOE.

There are unresolved questions as to the meaning of these uranium resource statistics. Except for the reserve figures, which are usually considered to be accurate within plus or minus 20%, the degree of confidence to be placed in these figures is unclear. We believe they are expected values and equally likely to be high or low. The uncertainty undoubtedly increases in going from the reserve to speculative categories, although how much is also unclear.

Table 4-19 presents estimates of foreign free-world uranium resources as given by DOE June 9, 1977. Foreign uranium reserves and resources are of increasing importance to U.S. utilities with the relaxation of restrictions on the use of imported uranium and uncertainties about the expansion rate of domestic producers.

From a strict viewpoint of resource existence, it appears quite likely that the United States has enough uranium to meet the needs of even the high case. However, resources in the ground, while necessary, are not by themselves sufficient. They must be found, mined, and milled.

URANIUM SUPPLY

How fast the nation's uranium resources can be discovered, mined, and milled is an unresolved question. Obviously, other things being equal, the higher the required output rates, the more difficult they will be to meet. However, other things are rarely equal. Due to long lead times of six to eight years, producers' expectations of future demand play a large role in determining what supply actually turns out to be. The high nuclear growth case, if the result of, or accompanied by, a strong state, federal, and utility commitment to nuclear power, might result in more uranium output at a given price than a low nuclear growth rate accompanied by such uncertainty that producers would be reluctant to invest. In such a case, uranium prices might well be high, not because of real costs but because of risk factors. Any uranium price path into the future is thus not only a function of real costs, including a normal rate of return, but of producer expectations along the expansion path.

Table 4-17

U.S. URANIUM RESOURCES, JANUARY 1, 1977
(thousand tons U_3O_8)

U_3O_8 Forward Cost (dollars/lb)	Proved Reserves	Potential			Total
		Probable	Possible	Speculative	
$10	250	275	115	100	740
$10-$15 increment	160	310	375	90	935
$15	410	585	490	190	1675
$15-$30 increment	270	505	630	290	1695
$30	680	1090	1120	480	3370
$30-$50 increment	160	280	300	60	800
$50	840	1370	1420	540	4170
By-product*	140	--	--	--	140
Total	980	1370	1420	540	4310

Source: DOE.

Note: This table does not include estimates for areas not yet evaluated by DOE. Furthermore, forward costs exclude sunk costs, rate of return or profit, and income taxes. It has been estimated that inclusion of these costs would increase forward costs by a factor of 1.5 to 1.7.

*By-product of phosphates and copper production. This 140,000-ton by-product figure is generally believed to be too high. Current thinking places the correct figure at around 60,000 tons.

Table 4-18

GESMO REPORT--U.S. URANIUM RESOURCES
ANTICIPATED WITH ADDITIONAL GEOLOGIC DATA
(thousand tons U_3O_8)

U_3O_8 Cutoff (dollars/lb)	Proved Reserves	Potential			Total Conterminous United States
		Probable	Possible	Speculative	
$10	270	440	420	500	1630
$10-$15	160	215	255	500	1130
$15-$30	210	405	595	1000	2210
$30-$50	200	400	600	1000	2200
Total	840	1460	1870	3000	7170
By-product*	140	--	--	--	140
Total conterminous United States					7310
Alaska					1400
Total domestic					8710

Source: GESMO, U.S. Nuclear Regulatory Commission, NUREG-0002, August 1976, Vol. 4, Chapter XI, Appendix D, Table XI(D)-2, p. XI(D)-5.

*See footnote on Table 4-17. The amount should probably be closer to 60,000 tons.

Table 4-19

URANIUM RESOURCES, OTHER COUNTRIES
(\$30/lb U_3O_8)

	Reserves[a]			Potential[b]	
	Thousand tons	%		Thousand tons	%
Sweden	390	23	Canada	790	61
S. and S.W. Africa	360	22	Australia	100	8
Australia	310	19	S. and S.W. Africa	100	8
Canada	225	13	Spain	60	5
France	70	4	France	50	4
Other	310	19	Other	190	14
Total	1665	100	Total	1290	100

Source: DOE, June 9, 1977.

Note: This table does not include People's Republic of China, USSR, or associated states of eastern Europe.

[a]Reasonably assured.

[b]Corresponds approximately to U.S. "probable" category; does not include amounts that would be classified in the United States as "possible" or "speculative."

Given that uranium producers are concerned about declining orders for new nuclear plants, that they have suffered several times from overexpansion in the past as a result of rosy nuclear growth expectations, and that some surplus supplies have overhung the market as a result of uranium enrichment policies, uranium producers are likely to be cautious about future expansion. At a recent International Atomic Energy Agency meeting, one industry executive estimated that surplus supplies tied up by enrichment contracts amount to 80,000 tons worldwide and 50,000 tons in the United States (1).

Figure 4-4 shows the present report's estimate of required future uranium reserve additions for the cases of Table 4-12 compared with reserve additions in the $30 forward cost category for the period 1950-1976, where the $30 figure is in constant 1975 dollars. This is not the series reported annually by DOE, which is in current dollars. The 1965-1975 figures are estimates of the constant dollar reserve addition figures made by Klemenic and Sanders of DOE's Grand Junction office. The earlier figures are this report's allocation of $30 (constant 1975 dollars) to earlier periods. This does not involve increasing the DOE estimates of $30 reserves plus past production. It is merely an attempt to recognize that some of the material now reported as $30 reserves was, in fact, discovered earlier. Since much of the higher-cost material is associated with lower-cost material, it must have been, in effect, discovered along with the lower-cost material but not reported at that time because it was not of economic interest.

The "can do" projections of uranium productive capacity by the DOE Grand Junction office are almost certainly well above what industry is likely to do. DOE is aware of the deficiencies of present studies and is seeking to improve its methodology. A recent S. M. Stoller Corporation report on uranium made for the FEA found that "the domestic uranium supply sector can satisfy the bulk of U.S. utility needs over the time frame considered in this study (1977-1996) if these needs are well-enough defined to be perceived as real, if the incentives to do so are commensurate with the business risks entailed, and if applicable rules and regulations at the federal, state, and local levels realistically reflect the balance that must be struck between national energy imperatives and environmental protection goals" (1).

It seems doubtful that these conditions will be fully met. It seems more likely that surplus uranium supplies overhanging the market, plus uncertainty about the future of nuclear power, will produce a further softening in the uranium market in

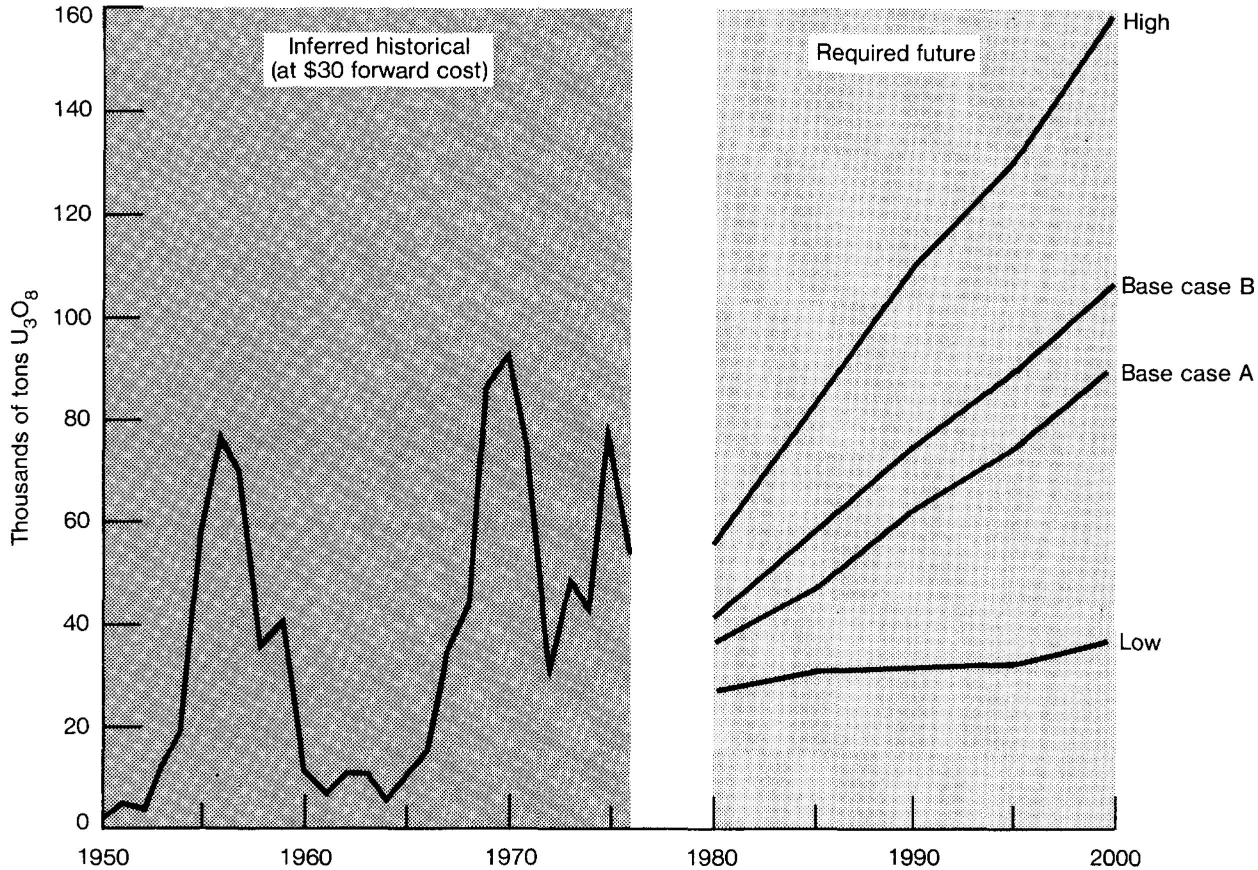


Figure 4-4. Uranium Reserve Additions

constant dollars--and that this, in turn, will result in the development of less than desired amounts of new uranium capacity. If, after a few years, it appears that uranium requirements are trending toward the low uranium projections of Table 4-3, uranium prices would probably decline significantly. Lower prices would prevail until extensive new exploration and development were required; then prices would rise sharply.

If the base nuclear growth case materializes, spot prices are likely to show some weakness (in constant dollars) until perhaps the mid-1980s, after which they may rise fairly rapidly until exploration and development catch up again. The rise might be tempered by the potential availability of substantial amounts of uranium available for import.

Expectations of the high uranium requirements case would probably result in, after a few years, gradually rising uranium prices--the rate of price rise being somewhat mitigated by timely producing-industry expansion and foreign imports.

Various current projections of uranium prices in 1975 dollars are shown in Table 4-20. These are plotted in Figure 4-5.

Uranium prices have rarely been strictly cost-based (i.e., costs plus a normal rate of return). In the early days of the industry, price and other incentives were in effect. Later, when uranium was in oversupply, the Atomic Energy Commission paid less than full costs, excluding various sunk costs. This subject is discussed at length in EPRI EA-498, <u>Price Formation in the Uranium Industry</u> (RP666). More recently, uranium prices have risen sharply in response to anticipated shortages. Currently growing stockpiles at various levels and reductions in nuclear power growth expectations may indicate another swing in prices, although it is necessary to distinguish between constant dollar prices and real prices, which may move in opposite directions.

On the low side, average uranium prices are probably bounded by what might be called accounting or financial costs, including a normal rate of return. On the high side, average uranium prices are probably bounded by cash flow needs of the producers, including interest and dividend payments, to support required levels of expansion. This high-side average is sensitive to expansion rates, whereas the low-side average is not. Average prices of uranium are likely to fluctuate in this range, with perhaps a tendency to move toward the upper limit as uncertainty

Table 4-20

URANIUM PRICE PROJECTIONS
(1975 dollars/lb U_3O_8)

	Cumulative U_3O_8 Production (thousand tons)	GESMO	NUS	Stoller*	Foster	De Halas		SRI
						Low	High	
1985	487	29	30	30	--	30	40	22
1990	694	30	32	33	--	30	40	25
1995	982	32	35	38	--	30	40	28
2000	1354	36	43	44	39	30	40	31
2005	1800	50	52	--	44	--	--	33

Note: Some interpretation has been used in placing these figures on a common basis. There may be some error.

*Work by S. M. Stoller Corp. was subsequent to the EEI Nuclear Fuel Cycle study, which Stoller (the basic source of EEI estimates) believes a useful refinement of the EEI work.

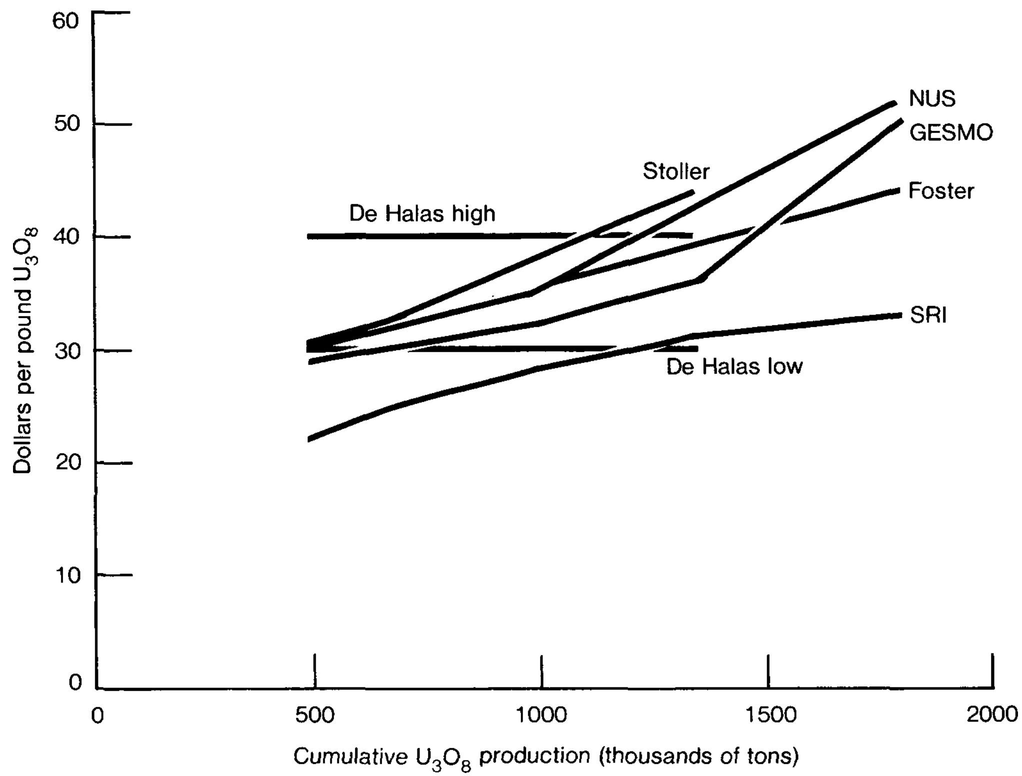


Figure 4-5. Projected Uranium Prices Normalized From Various Sources

and risk factors push producers toward the high-side average. However, there are instabilities building in the uranium market which are likely to lead to substantial variations in the individual prices which make up the averages. In particular, spot prices, as opposed to long-term contract prices, may show great variation.

Figure 4-6 shows estimated financial basis costs and estimated prices based on cash flow requirements for case B. The financial basis prices are clearly too low for the foreseeable future because they do not reflect the substantial risk inherent in present market conditions. Perhaps equally important, they do not reflect the higher costs which are likely to result from higher prices, both as a result of low grading by producers (a wise conservation measure) and the tendency of wages and other costs to rise more rapidly when prices are favorable. Figure 4-6 is in constant 1975 dollars. Figure 4-7 shows the same data assuming 5% inflation per year and also includes DOE data on contract prices. It is interesting to note that the financial basis, inflated at 5%, tracks the DOE contract series fairly well for some years.

NOTES AND REFERENCES

1. Nucleonics Week, May 12, 1977, p. 15.

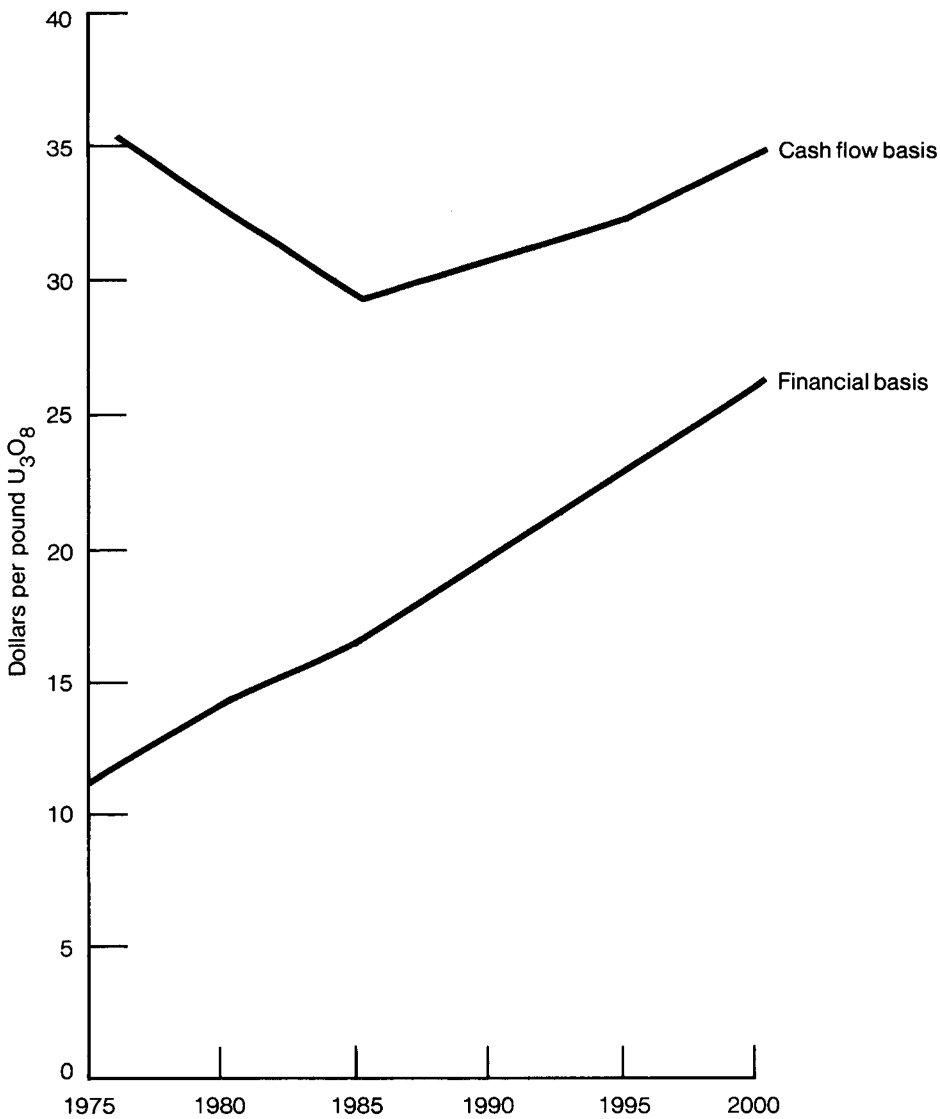


Figure 4-6. Average Uranium Price on Financial and Cash Flow Bases — Case B Requirements (constant 1975 dollars)

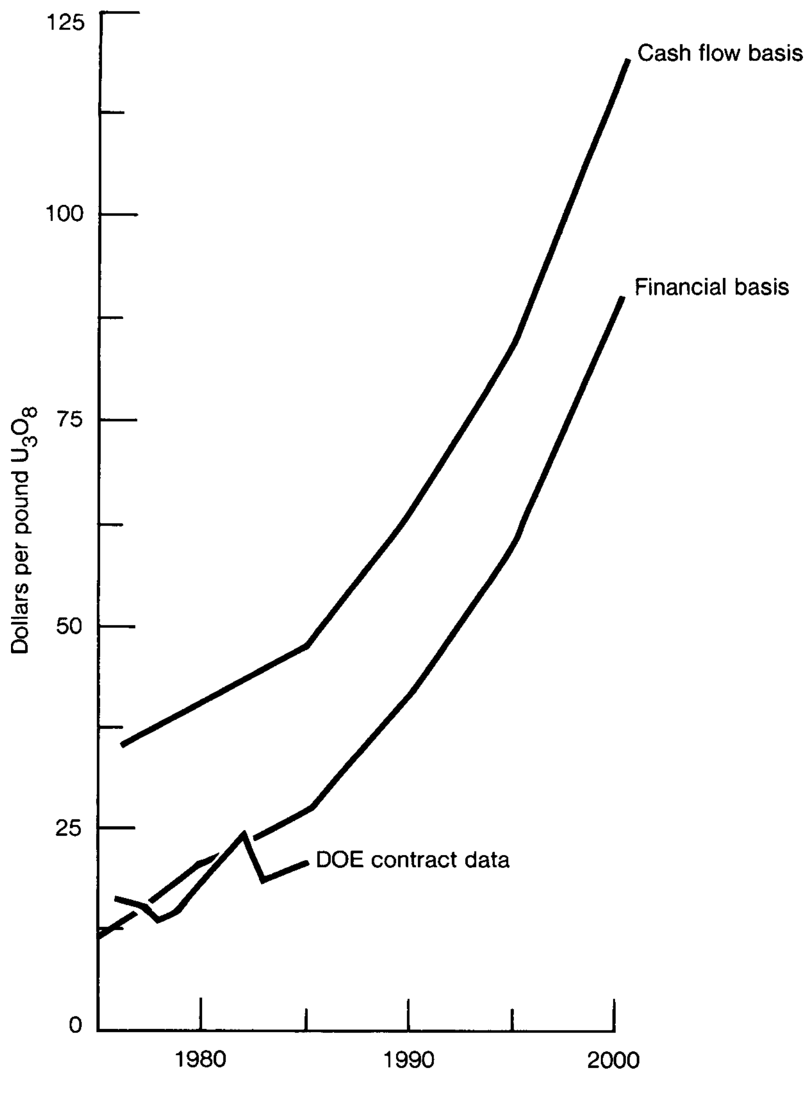


Figure 4-7. Average Uranium Price on Financial and Cash Flow Bases — Case B Requirements (inflation at 5%/yr from 1975)

Section 5

ELECTRICITY SUPPLY

This section is concerned with the electric utility industry as an industry. An industry is more than a collection of firms, just as a power system is more than a collection of power plants with transmission and distribution equipment. Historically, for any industry, it is possible to add individual firm historical statistics, such as sales, revenue, and generation statistics, to obtain industry totals. It is less possible, however, to add individual firm or system projections to obtain consistent industry projections. Particularly for the long run, simple summing up ignores industry dynamics.

Interactions between firms within and outside the utility industry are sometimes considered less important than those in other industries because of the regulated nature of the utility industry. On the demand side, there may be some truth to this view, although electric utilities have historically competed with one another for industrial loads, as well as competing with heating oil and natural gas suppliers for residential, commercial, and industrial loads.

On the supply side, though, industry dynamics play a strong role. Firms compete with each other for advantageous fuel supplies--for example, coal and uranium supplies in recent years. Indeed, the active participation of utilities in the search for and development of uranium and coal supplies, and in some cases of oil and natural gas supplies, adds another dimension to the industry. Utilities also place large orders for equipment and architectural/engineering services in the same markets, frequently in time frames which create strong market interactions. There is technical competition between utilities in terms of plant and system performance, and there is an interaction in the development and adoption of new technologies. Still another aspect of industry dynamics involves interconnections between utilities and the participation of individual utilities in power pools. Finally, regulation by state and federal authorities adds complexity, if not dynamics, to projections of the industry's future.

It is thus a dynamic industry whose future performance supply projections attempt to capture. As yet, our depictions of the industry are elementary and do not represent all the dynamics of power production. Future supply forecasts will move toward a more complete representation and will also consider the industry in a regional context.

THE INDUSTRY

Electric utilities currently purchase about one-third of the energy consumed by the nation and then transform it to a form preferred for many uses by consumers, transmit it to consuming centers, and distribute it to ultimate customers. The industry is also increasingly being considered as a vehicle for implementing national conservation, environmental, and R&D policies. The capital-intensive nature of the industry places a large demand on the nation's financial resources. It currently requires directly over 10% of gross private domestic investment and indirectly, through its demands for fuel, large investments by other energy industries.

One of the strengths of the industry is its heterogeneous nature, which means that many types of alternative energy systems--large and small, hard and soft, private and public--have been and are being explored at the practical level.

The industry consists of about 3500 individual utility systems which can be characterized as investor owned, public federal, public nonfederal, or electric cooperative. Investor-owned utilities account for over 75% of both total generating capacity and customers served. Most of these systems generate, transmit, and distribute their power to their customers. Federally owned systems, which include the Tennessee Valley Authority, the largest single system in the nation, and the Bonneville Power Authority, operate primarily at the wholesale level. Public nonfederal systems include municipally owned utilities, state power authorities, and public utility districts. These account for about 9% of total generating capacity and range from very small municipal systems to the Los Angeles Department of Water and Power, which serves over one million customers. Electric cooperatives are principally small systems located in rural areas. Ordinarily, these systems do not generate their own power, but purchase electricity from larger wholesalers. However, there has been a tendency in recent years for such systems to generate more of their own power, either directly or through participation with investor-owned utilities in the ownership of new power plants.

One of the characteristics of the electric utility industry which must be considered in any analysis is the degree to which it is regulated. This introduces constraints which some other energy industries--for example, coal mining and petroleum refining--have not experienced. Regulation is usually at the state level; however, in a few cases, it occurs at either the city or the county level. There also is regulation by FERC, which has a legislative mandate in the area of hydroelectric projects, interstate wholesale power sales, and establishment and maintenance of uniform financing accounting systems. Other federal agencies with regulatory responsibilities include the Securities and Exchange Commission (SEC), the Nuclear Regulatory Commission (NRC), and the Environmental Protection Agency (EPA).

INDUSTRY CONCERNS

All industries face problems in adjusting to a changing world. Many of the problems, such as rising costs, are common to all industries; other problems are more specific. For readers not intimately familiar with the utility industry, some of the challenges faced by this industry that differ, at least in degree, from those faced by other industries are discussed as background for the forecasts. In general, they do not constitute specific assumptions made in the process of forecasting; nevertheless, they are factors which must be considered, at least in a subjective manner, because they will influence the future supply of electricity. Among the more important concerns that go beyond the conventional concern about costs are issues of regulation, service reliability, environmental quality, and the industry's use as a tool of economic and social policy.

Regulation

State and federal regulatory authorities, in attempting to discharge their legal responsibilities and in some cases to respond to what they perceive to be the trend of public concern, are probing ever deeper into questions of public convenience and necessity, costs, and rates of return. Many of the problems in these areas have arisen because of inflationary trends in the economy; delays in plant construction, partially due to environmental and safety questions; rising real fuel costs; and a concern for conservation. In general, there are no well-established answers to many of the questions which utilities and regulatory commissions now face. How fast, for example, will power demands grow in the future? How serious might power shortages be in terms of employment and economic activity? Will the capital markets provide the funds needed for new plant construction? The attempts by utilities and regulatory commissions to find the answers to these questions, often in a political atmosphere, adds to the uncertainty of any projections of the future.

Adequacy and Reliability

Adequacy of capacity in the next decade and beyond is of major concern to the industry and should be of greater concern to the nation. The analysis here does not deal with the question of adequacy of capacity for several reasons, but it is a crucial question and is being increasingly addressed in the work of the Supply Program.

Closely related to the question of adequacy is the issue of reliability. We regard adequacy as broader than reliability, but the usage of the term is not standard. Reliability, as used in this context, refers to the reserve margin that electric utilities should maintain in order to properly serve customers. If utilities maintain large reserve margins, the probability that customers will face blackouts or interruptions of service is small. Utility customers must, however, pay for the additional capacity. Conversely, if utilities maintain small reserve margins, then the probability of service interruption increases. For a number of years, utilities have formed formal or informal power pools which allow them to benefit from other utilities' generating capacity. Essentially, power pools recognize that system peaks are noncoincidental, and therefore utilities borrow or buy power from one another via a transmission line. There has been some movement lately to encourage increased levels of pooling. It must be recognized, though, that the cost of transmission is not trivial. Thus the trade-offs must be considered between transmission costs, capacity costs, and noninterruption of service to utility customers.

Environmental Factors

Perhaps the most difficult items to handle in forecasting are environmental factors. In the past decade, federal and state governments have become increasingly involved in the issue of environmental safeguards affecting the utility industry. In the United States, the first major federal law affecting the utility industry in the area of air quality control was the Clean Air Act of 1967. The Clean Air Act amendments of 1970 and of 1977 tended to increase the stringency of environmental control. The 1967 act embodied the concept that air cleanup required a national effort, but it specified that the state should retain primary authority and responsibility over environmental control. The 1970 amendments provided for development and enforcement of two kinds of standards for ambient air quality: primary standards necessary to protect health, and secondary standards desirable to protect welfare (which encompasses all aspects other than human health, including the preservation of other organisms, property, and esthetics). The secondary standards are usually more stringent than the primary standards. The Clean Air Act amendments of 1970 have three types of standards which affect the electric utility industry.

- National Ambient Air Quality Standards: For each pollutant in question, EPA issues an air quality criteria document which establishes the basis for decisions about its health and welfare effects. Then EPA sets permissible ambient air concentration levels for both primary and secondary standards.
- National Emission Standards for Hazardous Air Pollutants: Emission standards are established by EPA for stationary sources emitting pollutants which "may cause or contribute to an increase in serious irreversible or incapacitating reversible illness." These are emission standards rather than ambient air standards, but they are based on health considerations.
- Standards of Performance for New Stationary Sources: These are emission standards established by EPA which reflect the degree of emission limitation attainable through the application of the best adequately demonstrated system of emission reduction, taking into account the cost of such reduction.

In the 1960s, the concern of environmental regulations was with reducing air pollution in polluted areas, giving little or no thought to the preservation of otherwise clean areas. Until about 1972, the implementation pattern for these regulations was to clean up dirty areas progressively and to allow increased levels in clean areas as long as they did not exceed the air quality standards. Now, in areas where pollution exceeds ambient air quality standards (called "nonattainment areas"), regulations call for a procedure known as the offset policy: Before any new pollutant source is permitted, there must be a commensurate reduction in the emission from an existing source in that area.

New Economic and Social Responsibilities

The growing role which the electric utility industry will play in the nation's future is placing special economic, social, and environmental responsibilities on the industry which did not exist, or which were much less important, when the industry was smaller relative to the economy. The industry is moving, sometimes reluctantly, to meet these new responsibilities in many ways, including vigorous support of research and development on new technologies intended to improve their economics and protect the environment.

One of the major problems faced by the industry is balancing its newfound responsibilities. The "buck" stops at the door of the utility which must balance environmental, conservation, and economic responsibilities at the practical, everyday business level, at a time when there is no agreement in society on the proper balance and when government seems to pay lip service, not to balancing, but to the impossible task of optimizing each of these interdependent factors individually.

Except for the cost factors, none of the industry problems discussed in this section are dealt with explicitly in the subsequent material. However, they form part of the background against which the projections are made, and even though they enter into the forecasts only informally, it is important for the reader to be aware that these problems contribute significantly to the uncertainty about the industry's future. Their successful resolution is a challenge not only to the industry, but also to state regulatory authorities and the federal government.

FUTURE GROWTH

Recent increases in electric utility costs and rates, combined with the slowdown in economic activity, have resulted in declines in the growth rate of electricity sales. Table 5-1 shows electricity sales in trillion kilowatthours for the total utility industry for selected years between 1930 and 1975. It also shows the annual growth in utility sales for each period. The 1974 reduction in total electricity sales was the first for the industry since 1946.

There is currently some dispute about whether a pattern of rising electricity prices in the future will continue to dampen the rate of growth of electricity sales. The estimation of price elasticity for electricity--that is, the extent to which rising prices reduce the level of sales which would otherwise exist--is currently under a great deal of investigation. While there is dispute over the estimated value of the elasticity, there is considerable evidence to suggest that the demand for electricity is indeed responsive to changes in electricity price, although the size of the response is still unsettled. Therefore, one would expect a continued increase in prices to result in a pattern of electricity growth rates which are lower in the future than they have been in the past.

Table 5-1

ELECTRICITY SALES

	Sales (trillion kWh)	Annual Growth per Period (%)
1930	0.075	-0.5
1940	0.119	12.2
1950	0.281	12.9
1960	0.684	9.1
1965	0.957	7.0
1970	1.396	6.5
1972	1.580	7.6
1973	1.705	7.9
1974	1.703	-0.1
1975	1.850	6.4

There are also currently a number of movements across the country to alter electricity rate structures in such a way as to dampen future peak load growth. Many utilities and several state regulatory commissions are currently conducting peak load pricing or load control experiments. Essentially, these involve charging a higher rate for consumption of electricity during peak periods than during off-peak periods. This proposed pattern of prices results from the cost of providing generating capacity required solely to meet peak demand. To the extent that peak load pricing policies are implemented in the future and are successful in reducing peak consumption, future growth rates for generating capacity but not necessarily for kilowatthours will be reduced still further.

The present report does not estimate the future growth of either generating capacity or energy demand; such specific forecasts must come out of the interaction between supply and demand. This report deals only with the supply side of the electric utility industry. However, some boundaries need to be set on the supply analysis, with specific assumptions to be made later. At this point, suffice it to say that for supply analysis, we assume that the industry will grow faster than the economy and will be more than twice as large in the year 2000 as it is today.

ECONOMIC CHARACTERIZATION

The electric utility industry was characterized for a long period of time as a declining-cost industry. Its declining unit costs were reflected in final prices to the consumer. Table 5-2 shows average revenue (price) in cents per kilowatthour between 1930 and 1976, both in current dollars and in constant 1975 dollars. As can be seen, electric utility prices declined until the early 1970s, both in real terms and in nominal terms. In the early 1970s, real electric prices were only 26% of 1930 prices. The leveling of the downward trend in prices in the late 1960s and early 1970s was the result of a number of factors. Economies of scale in unit size had been largely exhausted. Unit trains were in widespread use, so that transportation economies had been largely realized. Moreover, delivered fuel prices were sufficiently low that, in general, it did not make economic sense to spend the large amounts of capital required to further improve heat rates. A few pioneering utilities pushed newer generation technologies only to find unfavorable economics, so there was some tendency to back away from pressing technical efficiency further.

Table 5-2

AVERAGE REVENUE PER KILOWATTHOUR
(cents/kWh)

	Current Dollars	1975 Dollars
1930	2.66	8.58
1940	2.06	7.90
1950	1.81	4.05
1960	1.69	3.08
1965	1.59	2.71
1970	1.59	2.22
1972	1.77	2.27
1973	1.86	2.26
1974	2.30	2.51
1975	2.70	2.70
1976	2.89	2.73

Source: Edison Electric Institute, Statistical Yearbook, various issues.

Since 1973, electricity prices have been rising at a relatively rapid rate even in real terms. Table 5-3 provides a partial explanation for this trend. Fuel prices for coal, oil, and gas experienced a relatively rapid increase after 1973. For example, the oil prices paid by electric utilities in 1975 were over twice 1973 levels. Coal and gas prices also increased substantially during the same period. Prices for capital equipment for use in the electric utility industry have also increased during the past several years, and construction costs, due to lengthening lead times, have increased even more than equipment costs. Other factors contributing to the increases in the real cost of providing power were costs required to meet environmental standards, delays in power plant licensing, and increases in the costs of labor and equipment above the general rate of inflation. Thus the electric utility industry can be characterized as being in transition from a declining-cost industry to one of rising costs. How much and how fast costs will rise are matters of major concern to consumers, utilities, and, more broadly, the nation.

Table 5-3

ELECTRIC UTILITY FUEL PRICES

	Coal (dollars/ton)		Oil (dollars/bbl)		Gas (cents/thousand cubic feet)		Total (dollars/ million Btu)	
	Current	1975	Current	1975	Current	1975	Current	1975
1961	6.22	11.27	2.23	4.05	27.0	48.9	0.27	0.49
1965	5.83	9.95	2.10	3.58	25.7	43.9	0.25	0.43
1970	7.08	9.78	2.45	3.40	28.0	38.9	0.31	0.58
1972	8.69	11.19	3.78	4.87	31.9	41.1	0.41	0.54
1973	9.32	11.28	4.77	5.77	36.0	43.5	0.48	0.58
1974	14.81	16.17	11.21	12.24	51.2	55.9	0.89	0.97
1975	18.71	18.71	12.24	12.24	77.0	77.0	1.08	1.08
1976	19.29	18.23	12.34	11.67	104.8	99.1	1.15	1.09

Source: Edison Electric Institute, Statistical Yearbook, various issues.

SUPPLY FORECASTS

Thirty-four cases were analyzed with the electric utility price forecasting model to investigate parametrically the effect of changes in several important variables upon future electricity prices. Variations were considered in total generation growth rates, growth of nuclear capacity, availability of natural gas, capital costs, fuel prices, and interest rates.

The Model

The model used for the electricity price forecasts (ELECTP) is a simple simulation code developed by the Supply Program, with capacity mixes exogenously specified. The intent of the model is to provide a very fast-running price forecasting tool for parametric analysis.

The structure of the model is as follows. Generation plant types consist of coal, oil, gas, nuclear, hydro, turbine, and other. For each plant type, current capital costs, fuel prices, heat rates, load factors, and operation and maintenance costs are input to the model. The user must provide future annual changes in each variable.

The code calculates net annual additions to capacity (new additions minus retirements) given initial capacities and exogenous growth in capacity for each plant type. Fuel costs are calculated as dollars per million Btu times the heat rate for each plant type (except for nuclear, where a separate exogenous analysis provides input to the model directly in cents per kilowatthour). Annual fuel consumption for coal, oil, and gas is calculated by multiplying generation times the heat rate for each plant type. Conversion factors are then used to express total fuel use as tons, barrels, or cubic feet. Annual capital charges are calculated as a fixed charge rate times the capital cost.

The use of exogenous capacity growth rates by plant type is deliberate. Various optimizing and interfuel substitution or competition models exist, but we believe that they currently have limited forecasting ability. No model accurately represents the present uncertainty surrounding the growth of nuclear power. Nuclear versus coal decisions involve a host of noneconomic factors, many outside the control of electric utilities. In fact, it seems clear that strictly economic factors do not currently control new capacity decisions, although such decisions may be coincident with strictly economic factors in some cases. When the situation stabilizes so that plant choice can be reasonably represented by optimizing or fuel substitution models, we may then convert to their use.

Given exogenous nuclear forecasts (see the section on nuclear power) and the federal policy of phasing down natural gas use in power plants (by eliminating its use in baseload plants) and pushing for coal in preference to oil, the trend of the capacity mix is pretty well established without formal models. The code prints out, for each year and plant type, capacity, generation, load factor, share of total capacity, and fuel consumption. Finally, annual average electricity prices (revenues per kilowatthour) are shown. The capital, fuel, and operation and maintenance components are shown also. Generation costs are converted to prices, with the inclusion of transmission losses and transmission and distribution cost factors.

Input Data

The major input requirements for the cases analyzed here consist of initial capacities, fuel prices, capital costs, and their rates of change between 1975 and 2000. Initial capacities were taken from studies by the National Electric Reliability Council (1) and the Federal Energy Administration (2). Base case capacity growth rates were an attempt at a consensus between figures published by NERC (1), FEA (2, 3), and ERDA (now DOE) (4). Initial fuel prices were taken from FPC (now FERC) data (5). Rates of change in real fuel prices were based on various sources, including EPRI EA-411 (6) and EPRI EA-433 (7). Since the analysis is parametric, fuel prices are not specifically tied to any one set of fuel cost projections elsewhere in this report. Base case capital costs used were EPRI estimates (8). Table 5-4 shows initial values and assumed rates of change for base case capacities and fuel costs. All money costs are given in constant 1976 dollars.

Three different levels of generation in the year 2000 were assumed in order to explore the sensitivity of the average cost per kilowatthour to the customer (required revenue) to various industry rates of growth. Total generation assumed for the high-demand case in the year 2000 was 7.5 trillion kilowatthours. Generation was assumed to be 6.25 trillion kilowatthours in the base case and 5.0 trillion in the low case. In one set of cases, the effect on power costs of holding nuclear capacity in the year 2000 constant at 380 gigawatts while varying total demand was examined. In another set of cases, the level of demand was held constant and the amount of nuclear capacity varied. In most of the cases, coal was assumed to be the swing fuel whose volumes changed with changing amounts of nuclear power under constant demand assumptions. The capacity mix for various demand cases is shown in Table 5-5.

Table 5-4

BASE CASE INPUT ASSUMPTIONS

	Capacity		Fuel Price*	
	1975 GW (e)	Annual Growth (%)	1975 Dollars/ Million Btu	Annual Growth (%)
Coal	195	4.3	0.86	0.5
Oil	119	2.0	2.00	1.7
Gas	69	0.9	0.75	2.0
Nuclear	39	9.5	0.90	0.3
Hydro	56	1.0	0.00	0.0

*Fuel prices for 1975 are from Edison Electric Institute, Statistical Yearbook, 1975, p. 50, except for nuclear fuel (see below).

Annual growth rates were in general derived from the remainder of this report on the basis indicated below. No attempt was made to establish a specific relationship, since fuel price is considered a parameter in the cost analysis.

Coal: Table 3-4 shows a steady to declining national average price for steam coal sold in the open market FOB per ton. A changing mix of coal quality, with increasing amounts of lower-Btu western coal, will tend to offset the lower per-ton prices projected, and Table 3-6 includes gradually increasing real transportation costs for coal. These factors are taken to result in a 0.5% per year increase in real coal prices.

Oil: The proportion of output generated by oil-fired plants is anticipated to decline. Consequently, oil prices do not weigh heavily in the total fuel cost figures. However, the average annual compound growth rate from $12.57 per barrel ($2.00 per million Btu) to the $19.25 per barrel predicted for residual fuel oil in the year 2000 in Table 2-9 is 1.7% per year.

Natural gas: No new baseload natural-gas-fired plants are projected in this study, and the actual volume of natural gas burned by utilities in the year 2000 is predicted to be about one-half that consumed in recent years. The field price of domestic natural gas is projected to increase at over 5% per year during the forecast period. It is very difficult to estimate how fast the price of natural gas used by utilities under conditions of declining volume of use will rise. It is assumed that utilities using gas will tend to hold on to the lower-priced contracts, that some gas for peaking purposes will be available at special rates, and that gas produced by utilities or their subsidiaries will cost somewhat less than the average. We have used a 2% per year rate of increase. It could be greater. However, since the price is not used to determine rates of installation of gas-fired capacity and total gas consumption declines, use of a higher gas price would result in only small increases in average revenue required per kilowatthour.

Nuclear: This is not a 1975 cost. In the nuclear case, for calculation reasons we opted to take into account certain prospective near-term adjustments and use a lower growth rate for the future. The specific composition of the 9 mills/kWh is shown below. No uranium or plutonium reprocessing or recovery is assumed.

		Mills/kWh
U_3O_8	$25/lb (0.45 kg)	2.1
Conversion	$4/kg	0.1
Enrichment	$100/kg	2.1
Fabrication	$120/kg	0.6
Long-term storage	$400/kg	1.2
Subtotal		6.1
Carrying charge		2.8
Total		8.9 (rounded to 9 elsewhere)

Table 5-5

CAPACITY MIX IN THE YEAR 2000: ALTERNATIVE CASES
(GW [e])

	Coal	Oil	Gas	Nuclear	Hydro	Other	Total
High demand	819	196	5	380	72	51	1523*
Base demand	560	196	5	380	72	51	1264
Low demand	362	196	5	380	72	51	1066
No gas phaseout (base demand)	521	196	69	380	72	51	1289
300 nuclear (base demand)	631	196	5	300	72	54	1258
500 nuclear (base demand)	440	196	5	500	72	54	1267

*The EPRI Technical Assessment Guide, June 1977, forecasts total capacity in the year 2000 to be 1680 GW (e). Approximately 300 GW (e) of the total are forecast to come from hydro, geothermal, solar thermal, and storage. The remaining 1380 GW (e) are forecast to come from coal, oil, and nuclear. Our total for coal, oil, and nuclear shown above is 1395 GW (e), essentially the same. We thus have less capacity in the geothermal, solar-thermal, and storage categories. Since the load factor on such facilities may be low, we are probably closer on power production from nonconventional facilities than on capacity.

Table 5-6 shows capital cost assumptions. Two other input assumptions should be noted. First, the fixed charge rate used was 13% for all existing plants in 1975, with an 18% rate used for all new plants. The higher rate for new plants is not intended to reflect inflationary increases in interest rates; rather, it reflects real capital market changes. Finally, several cases were examined with rates of increase in fuel price 25% above those indicated in Table 5-4.

Results

Average Revenue (Price) Forecasts. The principal results of the cases examined are shown in Table 5-7. Average revenue per kilowatthour sold (that is, delivered price) for each of the 34 cases is shown for 1975, 1985, and 2000. "High cap costs" and "low cap costs" refer to construction costs for all new plants at levels 10% above and below, respectively, those used in the reference (base) case. The real increases in plant capital costs which occurred in the recent past have not exceeded the 10% upper limit used in this study. "Low fixed charge rate"

Table 5-6

BASE CASE CAPITAL COST ASSUMPTIONS
(1976 dollars)

	Dollars/kW (e)
Nuclear	790
Coal (w/scrubber)	650
Coal (w/o scrubber)	550
Hydro	700
Oil[a]	420
Gas[b]	--

Note: Assumptions are based on values from EPRI Technical Assessment Guide, June 1977, rounded.

[a]Very few new plants constructed.

[b]No new plants constructed.

cases are those cases in which the fixed charges for newly constructed facilities are at 13% rather than 18%. A 13% rate was used for existing plants throughout the forecast period. The effect of this assumption diminishes with time, both as a result of the retirement of old capacity and the addition of new capacity. "No gas phaseout" cases allow natural gas baseload capacities to remain constant. Finally, variations in nuclear capacity growth rates account for the 300-, 380-, and 500-gigawatt nuclear capacities shown in the year 2000 cases.

As can be seen, year-2000 variations in calculated average revenues per kilowatthour in constant 1976 dollars are surprisingly small. They range from 3.20¢ per kilowatthour (high demand, low fixed charges) to 3.99¢ per kilowatthour (low demand, high cap, high fuel) in the year 2000.

One apparent result of the cases may be misleading. Table 5-7 shows almost no variation in estimated prices resulting from changes in the level of total demand. For example, the high-demand case results in a price of 3.69¢ per kilowatthour in the year 2000 with reference levels of fuel and capital costs. Reducing the level of demand to the base amount results in 3.71¢ per kilowatthour. Reducing still further to the low-demand level results in 3.74¢ per kilowatthour. The closeness of these prices is probably spurious; it results from holding other conditions constant. A high demand for electricity would, more likely, result in higher fuel

Table 5-7

PROJECTED AVERAGE REVENUE REQUIREMENTS
(cents/kWh, 1976 dollars)

	1975	1985	2000
High demand, base cap costs, base fuel, 380 nuclear	2.86	3.40	3.69
High demand, low cap costs, base fuel, 380 nuclear	2.86	3.29	3.52
High demand, high cap costs, base fuel, 380 nuclear	2.86	3.51	3.87
High demand, base everything else, low fixed charge	2.86	3.10	3.20
High demand, base cap costs, high fuel, 380 nuclear	2.86	3.43	3.75
High demand, high cap costs, high fuel, 380 nuclear	2.86	3.54	3.93
High demand, low cap costs, high fuel, 380 nuclear	2.86	3.32	3.58
Base demand, base cap costs, base fuel, 380 nuclear	2.86	3.37	3.71
Base demand, low cap costs, base fuel, 380 nuclear	2.86	3.27	3.53
Base demand, high cap costs, base fuel, 380 nuclear	2.86	3.47	3.88
Base demand, low cap costs, high fuel, 380 nuclear	2.86	3.29	3.60
Base demand, base cap costs, high fuel, 380 nuclear	2.86	3.39	3.78
Base demand, high cap costs, high fuel, 380 nuclear	2.86	3.50	3.95
High demand, base cap costs, base fuel, 300 nuclear	2.86	3.37	3.69
High demand, high cap costs, base fuel, 300 nuclear	2.86	3.48	3.86
Base demand, base cap costs, base fuel, 300 nuclear	2.86	3.33	3.69
Base demand, high cap costs, base fuel, 300 nuclear	2.86	3.43	3.86
Low demand, base cap costs, base fuel, 380 nuclear	2.86	3.33	3.74
Low demand, low cap costs, base fuel, 380 nuclear	2.86	3.24	3.57
Low demand, high cap costs, base fuel, 380 nuclear	2.86	3.42	3.91
Low demand, base cap costs, base fuel, 300 nuclear	2.86	3.30	3.71
Low demand, high cap costs, base fuel, 300 nuclear	2.86	3.39	3.88
High demand, base cap costs, base fuel, 500 nuclear	2.86	3.37	3.76
High demand, low cap costs, base fuel, 500 nuclear	2.86	3.27	3.58
Base demand, base cap costs, base fuel, 500 nuclear	2.86	3.33	3.79
Base demand, low cap costs, base fuel, 500 nuclear	2.86	3.24	3.61
Base everything, low fixed charge rate	2.86	3.09	3.23
Low demand, base everything else, low fixed charge	2.86	3.08	3.26
Low demand, base cap costs, high fuel, 380 nuclear	2.86	3.36	3.81
Low demand, low cap costs, high fuel, 380 nuclear	2.86	3.27	3.64
Low demand, high cap costs, high fuel, 380 nuclear	2.86	3.45	3.99
Low demand, base cap costs, base fuel, no gas phaseout	2.86	3.42	3.80
Base demand, base cap costs, base fuel, no gas phaseout	2.86	3.45	3.76
High demand, base cap costs, base fuel, no gas phaseout	2.86	3.48	3.73

prices (if fuel supply curves are positively sloped), and likewise could result in higher capital costs. Cases of greater interest may be the low-demand, low-capital-cost, base-fuel case (3.57¢ per kilowatthour); the base case of 3.69¢ per kilowatthour; and the high-demand, high-capital, high-fuel case (3.93¢ per kilowatthour). Some of these price forecasts are shown in Figure 5-1.

If the analysis in this study had included inflation, the estimated prices would have been substantially higher. Table 5-8 shows the data from Table 5-7 inflated at 5% per year through the year 2000. Figure 5-2 shows the essential data from Figure 5-1 replotted to use the inflated data from Table 5-8. Each set of data has its uses. Utilities must work in a world of inflated prices, paying inflated prices for fuel, labor, equipment, and construction and consequently obtaining revenues from consumers which will enable payment of these inflated costs. Similarly, investors are unlikely to continue providing the funds which the industry needs unless the real purchasing power of their dividends remains constant or increases. On the other hand, the performance of the industry and its relationship to the rest of the economy can perhaps best be judged in terms of constant dollars.

Comparison With Other Price Forecasts. A few other forecasts of electricity prices are shown in Table 5-9 for comparative purposes. Unfortunately, these forecasts contain widely divergent assumptions concerning future growth rates, generating capacity mixes, fuel and capacity costs, and interest rates. Work is under way to use the input assumptions of this study in the models associated with the forecasts listed in Table 5-9, as well as some others, in order to determine the extent to which the different prices produced by the models are the result of different assumptions.

Even in constant dollars, our year-2000 forecast average revenue (price) per kilowatthour is about the same as that of Manne (9) but significantly higher than the figures produced by the Joskow and Baughman (10) and Hudson and Jorgenson (11) models. The figures in the TRW study for ERDA (12) are considerably higher than ours. The FEA estimate does not go to the year 2000, but its estimate for 1985 is somewhat lower than ours.

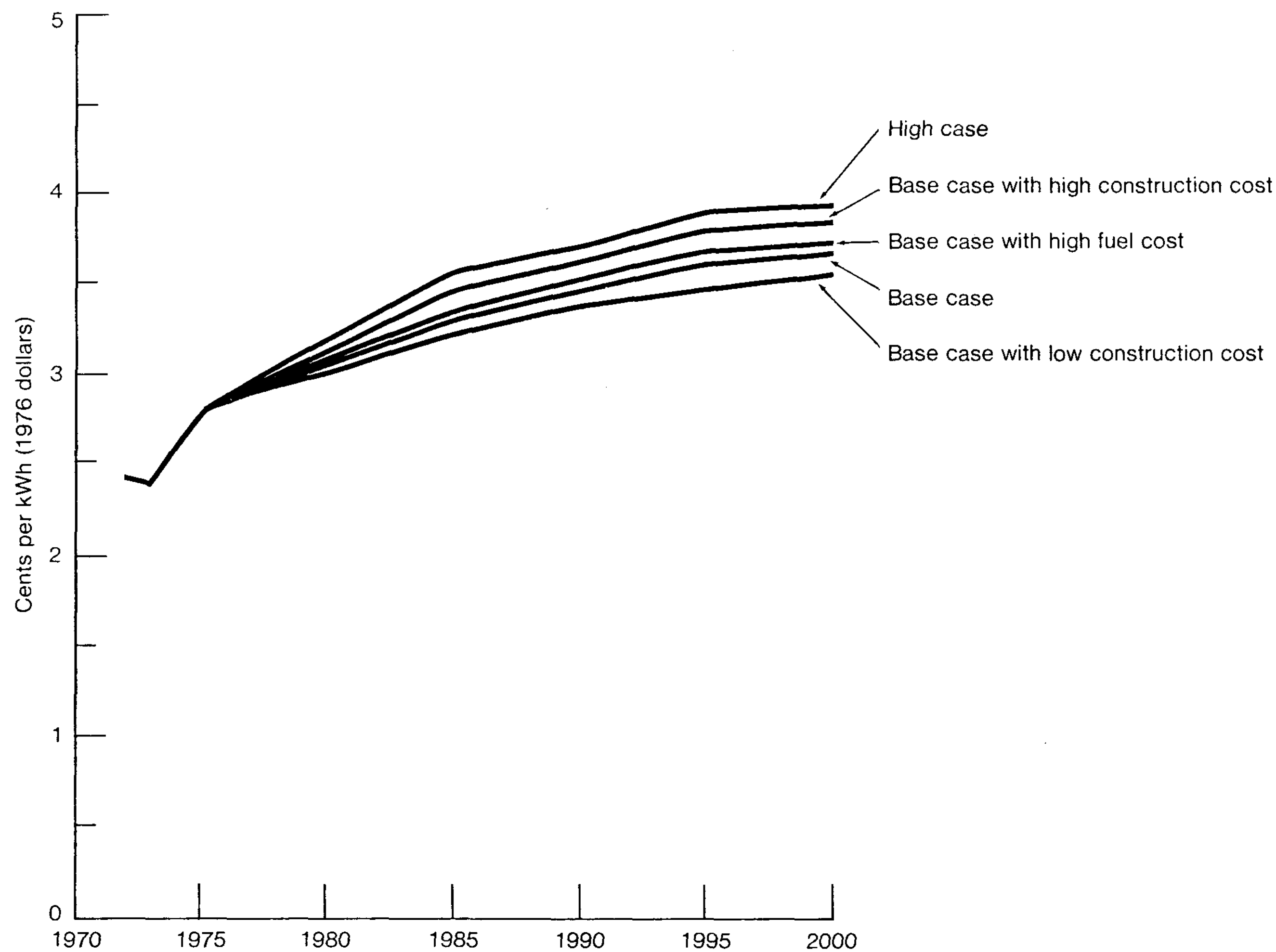


Figure 5-1. Average Revenue per Kilowatthour (in constant 1976 dollars)

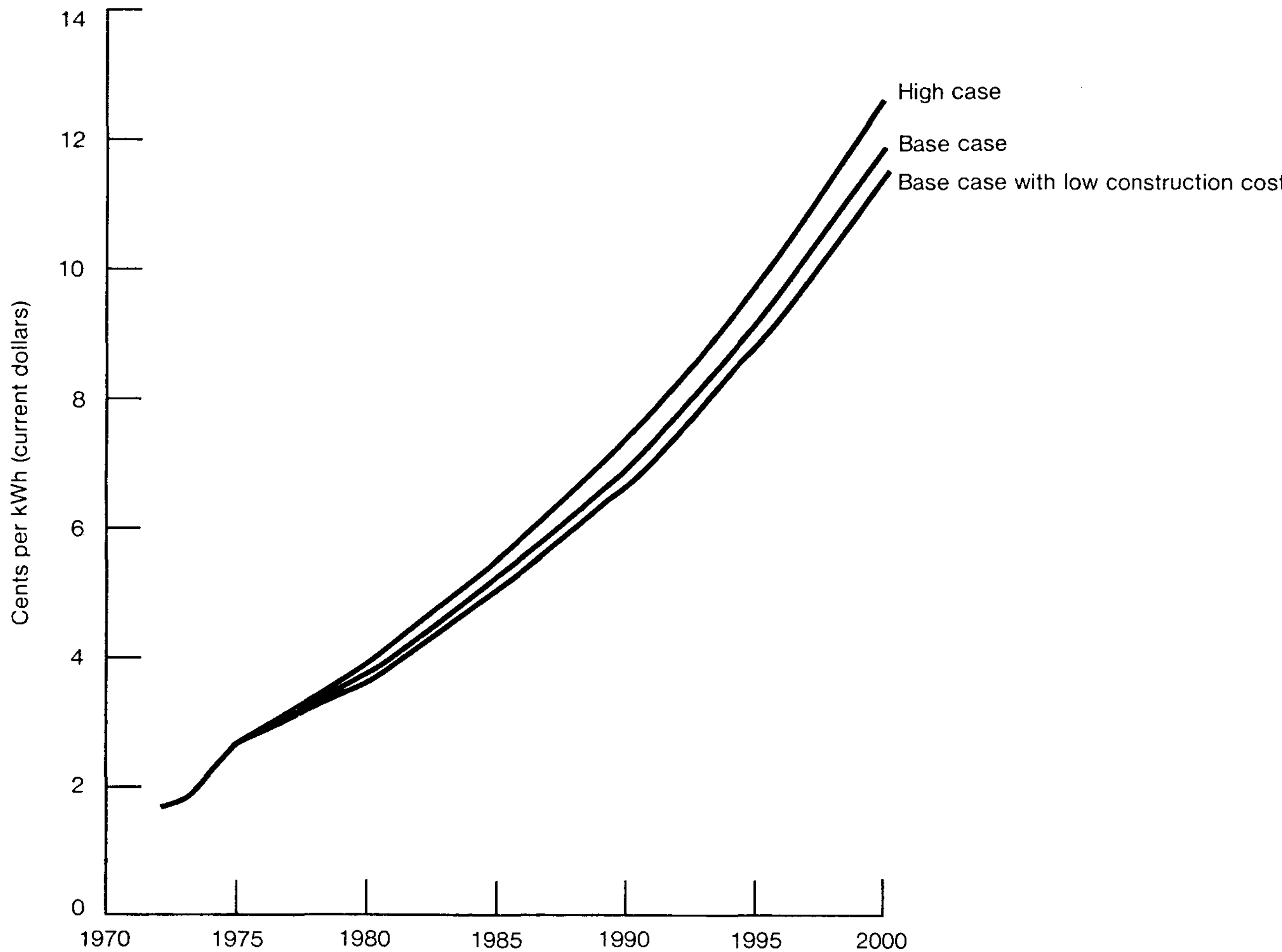


Figure 5-2. Average Revenue per Kilowatthour (in current dollars at 5%/yr inflation)

Table 5-8

PROJECTED AVERAGE REVENUE REQUIREMENTS
(cents/kWh, 5% annual inflation)

	1975	1985	2000
High demand, base cap costs, base fuel, 380 nuclear	2.86	5.54	12.50
High demand, low cap costs, base fuel, 380 nuclear	2.86	5.36	11.92
High demand, high cap costs, base fuel, 380 nuclear	2.86	5.72	13.11
High demand, base everything else, low fixed charge	2.86	5.05	10.84
High demand, base cap costs, high fuel, 380 nuclear	2.86	5.59	12.70
High demand, high cap costs, high fuel, 380 nuclear	2.86	5.77	13.31
High demand, low cap costs, high fuel, 380 nuclear	2.86	5.41	12.12
Base demand, base cap costs, base fuel, 380 nuclear	2.86	5.49	12.56
Base demand, low cap costs, base fuel, 380 nuclear	2.86	5.33	11.95
Base demand, high cap costs, base fuel, 380 nuclear	2.86	5.65	13.14
Base demand, low cap costs, high fuel, 380 nuclear	2.86	5.36	12.19
Base demand, base cap costs, high fuel, 380 nuclear	2.86	5.52	12.80
Base demand, high cap costs, high fuel, 380 nuclear	2.86	5.70	13.38
High demand, base cap costs, base fuel, 300 nuclear	2.86	5.49	12.50
High demand, high cap costs, base fuel, 300 nuclear	2.86	5.67	13.07
Base demand, base cap costs, base fuel, 300 nuclear	2.86	5.42	12.50
Base demand, high cap costs, base fuel, 300 nuclear	2.86	5.59	13.07
Low demand, base cap costs, base fuel, 380 nuclear	2.86	5.42	12.66
Low demand, low cap costs, base fuel, 380 nuclear	2.86	5.28	12.09
Low demand, high cap costs, base fuel, 380 nuclear	2.86	5.57	13.24
Low demand, base cap costs, base fuel, 300 nuclear	2.86	5.38	12.56
Low demand, high cap costs, base fuel, 300 nuclear	2.86	5.52	13.14
High demand, base cap costs, base fuel, 500 nuclear	2.86	5.49	12.73
High demand, low cap costs, base fuel, 500 nuclear	2.86	5.33	12.12
Base demand, base cap costs, base fuel, 500 nuclear	2.86	5.42	12.83
Base demand, low cap costs, base fuel, 500 nuclear	2.86	5.28	12.22
Base everything, low fixed charge rate	2.86	5.03	10.94
Low demand, base everything else, low fixed charge	2.86	5.02	11.04
Low demand, base cap costs, high fuel, 380 nuclear	2.86	5.47	12.90
Low demand, low cap costs, high fuel, 380 nuclear	2.86	5.33	12.33
Low demand, high cap costs, high fuel, 380 nuclear	2.86	5.62	13.51
Low demand, base cap costs, base fuel, no gas phaseout	2.86	5.57	12.87
Base demand, base cap costs, base fuel, no gas phaseout	2.86	5.62	12.73
High demand, base cap costs, base fuel, no gas phaseout	2.86	5.67	12.63

Table 5-9

COMPARISON: FORECAST ELECTRICITY PRICES
(cents/kWh average revenue, 1976 dollars)

	1985	2000
Manne*	2.80	3.60
Joskow and Baughman	2.05	2.54
Supply 77	3.37	3.71
FEA	2.9	--
Hudson and Jorgenson	2.6	2.5
TRW, Inc.		
Busbar costs	2.8	3.3
Probable costs*	3.6	4.4

Note: The average revenue estimates in this table are EPRI estimates derived from the studies indicated. In most cases, base years for dollar estimates have been changed; in two cases, estimates for nongeneration costs have been added. All forecasts were based upon different input assumptions.

*Assumes generation costs equal 70% of total average revenue per kilowatthour.

Fuel Consumption. Historical levels of fuel consumption, by fuel type, are shown in Table 5-10 on both an absolute and a market share basis. In Table 5-11, requirements for fossil fuels are shown for selected cases listed in Table 5-7. Utility coal consumption in the year 2000 varies from about 950 million tons per year (low power growth and base nuclear) to nearly 2200 million tons (high power demand and base nuclear). The base-demand, base-nuclear case requires about 1500 million tons of coal for utility use per year. This is over three times current utility coal consumption. Projected fuel consumption figures for 1985 are given below, where the results of this study are compared with the figures compiled by NERC.

The coal figures cited above do not include nonutility coal consumption or export requirements. Inclusion of these figures would increase the total quantities but would probably decrease the required growth rate in coal production, since these markets will probably grow at a slower rate than utility coal consumption.

Table 5-10

ANNUAL FUEL USE BY ELECTRIC UTILITIES

	Quantity		
	Coal (million tons)	Oil (million barrels)	Gas (trillion cubic feet)
1930	40	9	0.12
1940	52	16	0.18
1950	92	75	0.63
1960	177	85	1.72
1965	245	115	2.32
1970	321	336	3.93
1972	351	494	3.98
1973	388	560	3.64
1974	392	536	3.43
1975	406	507	3.15
1976	448	555	3.08

	Share of Total Generation (%)			
	Coal	Oil	Gas	Nuclear
1951	68.5	10.6	20.9	--
1960	66.3	7.6	26.0	0.1
1965	66.3	7.5	25.8	0.4
1970	55.0	14.2	29.1	1.7
1972	52.3	18.5	25.5	3.7
1973	53.4	19.8	21.5	5.3
1974	53.1	19.1	20.5	7.3
1975	52.9	17.9	18.6	10.6
1976	54.0	18.3	16.8	10.9

Source: Edison Electric Institute, Statistical Yearbook, various years.

Table 5-11

FUEL CONSUMPTION IN THE YEAR 2000

	Coal (million tons)	Oil (million barrels)	Gas (trillion cubic feet)
High demand (base nuclear)	2178	1076	1.6
Base demand (base nuclear)	1489	1076	1.6
Low demand (base nuclear)	964	1076	1.6
No gas phaseout (base demand)	1386	1076	4.3
300 nuclear (base demand)	1678	1076	1.5
500 nuclear (base demand)	1170	1076	1.6

Comparison With NERC Forecasts. The exogenous fuel mix used in these cases is compared with the NERC tabulations (1, 13, 14, 15) of utility plans in Table 5-12. Several differences should be noted. First, our forecasts include slightly more oil plants in the early years. This is in part influenced by FEA estimates (2). Also, 1975 capacities are slightly different. This is due to obtaining estimates from a variety of sources.

Nuclear capacity projections by NERC are similar to ours until 1985, where we project about 16% lower nuclear capacity. NERC, however, points out that its projections are probably too high by as much as 20% (14).

The generation figures reflect smaller differences than noted for capacity. Coal, gas, and oil projections are quite similar to the NERC estimates.

Finally, our fuel consumption estimates are similar. Natural gas consumption is higher, but that is in part due to our arbitrarily assigning all combustion turbine production to gas for the purposes of calculating fuel use.

Table 5-12

COMPARISON: NERC FORECASTS AND EPRI BASE CASE

Capacity (GW [e])

	Coal		Oil		Gas		Nuclear		Hydro		Total[a]	
	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI
1975[b]	193		122[c]		71[c]		39		59		505	
1980	242	237	106	132	53	41	73	71	65	59	605	569
1985	309	288	114	146	44	24	151	125	67	62	767	681

Generation (billion kWh)

	Coal		Oil		Gas		Nuclear		Hydro		Total[a]	
	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI	NERC	EPRI
1975[b]	848		281		282		168		297		1918	
1980	1130	1289	419	406	193	171	435	365	257	321	2561	2678
1985	1595	1563	461	448	106	101	897	632	267	338	3380	3228

Fuel Consumption

	Coal (million tons)		Oil (million barrels)		Gas (trillion cubic feet)	
	NERC	EPRI	NERC	EPRI	NERC	EPRI
1975[b]	431		502		3.0	
1980	611	619	764	724	2.1	2.6
1985	824	792	878	800	1.2	2.0

[a]"Other" not shown separately.

[b]Actual capacity is NERC, but see note below. Generation and fuel are FPC.

[c]70% of combustion turbine capacity is allocated to oil and 30% to gas. NERC figures for 1980 and 1985 in these columns do not include combustion turbines.

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