FUEL AND ENERGY PRICE FORECASTS

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LEGAL NOTICE

FOREWORD

EPRI and the electric utility industry require fuel price forecasts for use in their planning efforts. EPRI's Energy Analysis and Environment Division has a contract research program underway to develop information on which to base such forecasts. Work is being conducted to improve data, to design and develop improved methods of forecasting energy prices, and to reduce the margin of error in such forecasts. This work is a joint effort by the Energy Supply, Energy Demand, and Energy Systems Programs of the Division. As it is a long-range program involving considerable fundamental energy economic and analytical work, major results will not be available for some time.

In the meantime, EPRI required energy price forcasts for R&D planning and other purposes. Therefore, to assist the Energy Analysis and Environment Division staff in the preparation of interim price forecasts, the Energy Supply Studies Program let contracts with Stanford Research Institute,RP 795-1 (a separate report),and Foster Associates, RP 759-2, to prepare independent price forecasts to the year 2000.

While this study prepared by Foster Associates was designed primarily to aid the Energy Analysis and Environment staff, it is being published, in accordance with EPRI policy, so that it may be used by electric utility staffs and others.

It should be emphasized that the forecasts contained in this report are the contractor's and the publishing of them does not imply their endorsement by EPRI. The draft report was reviewed by the Project Manager and other staff members. Comments and critiques were forwarded to the contractor. As the study was designed to give independent price forecasts, the contractor was free to accept or reject the staff's comments.

Not surprisingly, given the complexity of the subject, the contractor and Project Manager did not agree on all the logic, data, and assumptions going into these price forecasts. The reader is cautioned to fully examine the basis of the forecasts before using them.

The Project Manager does feel that this report should prove to be extremely useful and should be a valuable aid to those trying to obtain a better understanding of future energy prices and the complexities surrounding them. Because of the contractor's background and funding limitations, the report devotes considerably more attention to the natural gas deregulation case than to the crude oil deregulation case. This in no way reflects a belief on the part of the Supply Program that crude oil deregulation is not at least an equally important subject or that there would not be a significant supply response from such deregulation. This does not imply any judgment as to the desirability of deregulation from the national viewpoint in either case, but is rather a judgment as to supply response.

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ABSTRACT

Foster Associates, Inc. has undertaken in behalf of the Electric Power Research Institute (EPRI) a technical study of fuel and energy prices over the period 1985 to 2000.

The report develops and sets out projections of energy prices in 1975 constant dollars, on a regional basis, for the United States over the period 1985 to 2000. The major sources of energy analyzed include crude oil and major petroleum products, coal and coal-based synthetic fuels, gas, and uranium. EPRI stipulated that electricty prices were not to be analyzed or projected.

A major stipulation of EPRI was that the price projections be developed within a given set of aggregate energy and electricity demand projections, as set out in the Edison Electric Institute study, <u>Economic Growth in the Future</u>. Accordingly, the emphasis of this study is on the cost and price aspects of the several sources of energy.

The price of each energy type is projected at different levels of commerce (e.g., points of production and points of consumption), requiring a forecast of the cost of production, transportation, and distribution. Delivered energy prices were estimated for four major end-use sectors: residential/commercial, industrial, electric utility, and transportation.

The two major findings of the study were as follows:

1. The real prices of all sources of energy will increase over the forecast period. Both gas and petroleum prices will continue to increase at a rate greater than that of coal, primarily reflecting the higher cost of incremental supplies. Uranium prices are also projected to increase, but could remain below that for coal delivered to the electric utility sector.

2. The range of energy price projections are attended in varying degree by great uncertainty. The bands of uncertainty, set out for each forecast, are considered as important as the price projections.

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SUMMARY

Foster Associates, Inc. has undertaken for the Electric Power Research Institute (EPRI) a technical study of fuel and energy prices over the period 1985 to 2000.

The study develops and sets out projections of energy prices in 1975 constant dollars, on a regional basis for the United States over the period 1985 to 2000. Each major energy type is priced out on a regional basis at different levels of commerce (e.g., points of production and points of consumption). Finally, energy prices are compared for four end-use sectors: residential/commercial, industrial, electric utility, and transportation.

In each of these projections attention is called to the great uncertainty of future prices. Percent ranges are set out to indicate the magnitude of these uncertainties. These bands of uncertainty are considered as important as the price projections themselves.

The major sources of energy for which prices are projected include crude oil and major petroleum products, coal and coal-based synthetic fuels, gas, and uranium. Electricity prices were excluded from the scope of work in accordance with EPRI stipulation.

Another major stipulation by EPRI was that the price projections be developed within a given set of aggregate energy and electricity demand projections as set out in the Edison Electric Institute (EEI) study Economic Growth in the Future. Furthermore, EPRI directed that the emphasis of this study be on price aspects of the types of energy analyzed. However, supply and demand projections were developed on a limited basis to test for correct directionality of the price forecasts.

The EEI projections were developed under three scenarios which encompass a broad range of prospective economic growth patterns in the United States: Case A, the high growth case; Case B, the moderate growth case; and Case C, the low growth case. Case B was selected as the bench mark for this study. In this case total primary energy demand was projected to increase at an annual average rate of 3.0 percent in the United States, from 77 quadrillion Btu in 1975 to 161 quadrillion Btu in 2000, with a range of uncertainty being +16 percent to -48 percent in the latter year. In Case B net electric utility generation was projected to increase from 1.98 trillion Kwh in 1975 to 7.11 in 2000, an average annual growth rate of 5.3 percent and with a range of uncertainty being +14 percent to -38 percent in 2000.

The directional findings of the study are presented below. It should be noted that it is impossible to present in a brief summary the complete set of projected prices because of the numerous analyses underlying these price projections. The reader should therefore refer to the main body of the report for the technical analyses and the detailed price projections:

1. The real price, as measured in 1975 dollars, of those types of energy analyzed in this study will increase in varying degree over the forecast period. Petroleum prices will remain at the high end of the spectrum relative to other primary energy prices. Gas prices are projected to approach petroleum prices. Coal prices while increasing will continue to remain below those of gas and petroleum. Uranium prices may remain below coal prices, based on a comparative cost per Kwh projection, measured at the electric utility bus bar. Synthetic fuels from coal are projected to be among the highest priced future sources of energy, based on the present technological mix.

2. The range of energy price projections are attended in varying degree by great uncertainty. Ranges of uncertainty were judgmentally estimated for all major energy sources. Each range should account for most of the expected variations in energy prices.

RANGE OF UNCERTAINTY:
VARIATION FROM MID-POINT
PRICES PROJECTED FOR 2000

Crude Oil	-46% to +34%
Gas	-49% to +34%
Coal	-35% to +150%
Uranium	-59% to +180%

3. On a national basis, the structure of U.S. energy supply will reflect and amplify trends currently manifested in the country. The EEI Demand Case B was used as the base line yardstick against which energy supply was compared. Over the forecast period imports of natural gas in the form of LNG are projected to triple, yet a supply-demand imbalance will probably still exist with respect to gas. This imbalance will likely require additional imports of oil, increased production of domestic coal, and impose a greater burden on electric demands. The higher cost of these incremental supplies will be a cause of higher real prices of energy.

4. The level of projected energy prices in the various end-use sectors will not only reflect aggregate changes in the national supply/demand balance, but will also be affected by factors unique to each end-use sector.

5. In the residential and commercial sectors energy consumption, as projected in Case B of the EEI study, will grow at an annual average rate of approximately 2.6 percent. According to EEI, over 70 percent of energy growth in the sector will be in electricity. Excluding electricity, over 80 percent of the fuel growth will be in oil, the balance in gas. As stipulated by EPRI, no analysis was undertaken to determine future electricity prices.

Burner tip price projections for both distillate fuel oil and gas were developed under two scenarios: one assuming the continuation of price regulation by the FPC with respect to wellhead prices of natural gas and by the FEA with respect to domestic crude oil prices, the other assuming deregulation of both natural gas and crude oil. The price projections for gas and distillate are set out at Chapter IV-C of the report.

Gas prices are projected to increase over the forecast period to a level near that of distillate fuel oil under both scenarios in all regions except New England where future gas prices are expected to continue exceeding the projected level of distillate prices.

6. Energy consumption in the industrial sector will be affected by both the diminishing availability of natural gas and future energy prices. Curtailments of natural gas will primarily affect boiler users. Higher prices of other fuels will have a substantial impact on decisions with respect to fuel selections and usage.

In the industrial sector, prices were projected for high and low sulfur coal, distillate and residual fuel oil, and gas. These projections are set out at Chapter IV-D of the report. Fuel oil and gas prices were projected under the regulated and free market scenarios. Gas prices at the burner tip are projected to rise to the level of fuel oil prices by 1985. This should serve to reinforce a shift to alternate fuels created by gas supply deficiencies. Coal prices are projected to increase but to remain at levels lower than both fuel oil and gas.

Directionally, the price projections suggest that prospective fuel consumption patterns may not change dramatically, except for shifts created by lack of gas supply. There is, however, the potential for greater coal utilization, which would be reinforced by Federal energy policies to restrict oil imports.

7. The electric utility sector will continue to be the largest consumer of energy over the forecast period, supplied by coal, oil and nuclear. The consumption of natural gas in this sector is expected to be phased out over the forecast period.

Future prices, set out at Chapter IV-E of the report, will also have an important impact on fuel use decisions by electric utilities. Oil will, for the most part, continue to be used in its traditional geographic markets; however, coal and nuclear will provide the major sources of energy to this sector. In order to test the coal-nuclear price interface, a breakeven "price" for U_3O_8 was calculated with respect to low sulfur coal. It was found that, on the basis of price, the potential for substantial nuclear power growth is within the range of reasonableness.

8. Regular grade gasoline was the primary product studied in the transportation sector. As with the other petroleum products, regulated and free market prices of gasoline were projected, as set out at Chapter IV-F of the report.

Due in part to higher prices and to mandatory efficiency standards, gasoline consumption is projected to grow at less than historical rates, as projected by EEI.

9. Underlying the level and structure of projected prices in the end-use sectors are the supply, cost and price of the major sources of primary energy - crude oil and petroleum products, coal, gas and uranium.

10. The OPEC cartel is projected to continue as a dominant factor in determining the price of world oil throughout the forecast period. In real dollars, Saudi Arabian light crude oil is projected to increase by more than 50 percent from 1976 to 2000, although this forecast could vary by ±100 percent. World oil prices are expected to continue influencing other energy prices in the United States, although this influence may wane during the latter part of the forecast period, due to rising costs of domestic energy sources.

11. Prices for crude oil produced in the United States reflect the increasing costs of finding and producing new sources of supply. The sources include cost of domestic crude from conventional areas of supply, North Slope crude, oil produced through tertiary recovery methods, and to a lesser extent, shale oil.

The projected cost of domestic crude oil was developed under two cases: a regulated price, and a free market price. The regulated case assumes continuation of the price control mechanism instituted through the Energy Policy and Conservation Act of 1975. The free market case projects that all domestic crude oil prices will equate to the foreign crude oil price delivered to the U.S. refineries after adjustment for quality differences. While the free market price would remain above the regulated price, the differential will be largely eliminated by 2000 due to the rising cost of finding and production.

Price projections for crude oil in the United States are set out at Chapter III-C of the report. The range of uncertainty associated with these price projections are substantial, reflecting uncertainties attending foreign oil prices, the cost of supplemental sources of oil such as tertiary production, and the uncertainties attached to the cost of exploration and development for domestic oil in the context of a depleting resource base.

12. Petroleum product prices will continue to reflect the mix and cost of crude oil feedstock delivered to the refinery, the refinery margin and transportation and distribution costs incurred for delivery to the market. Five key refinery centers in the U.S. were analyzed as supply points for petroleum products. Using this approach, product prices were projected for distillate fuel oil, residual fuel oil and gasoline at 17 metropolitan pricing point areas. While free market prices are expected to exceed regulated prices, the differential would narrow to about 15 to 20 percent by 2000, subject to the considerable range of uncertainties attending future crude oil prices.

13. The price of natural gas is projected under two alternate cases - continuing price regulation and free market conditions. In the price regulation case, it is assumed that the Government will continue to set the average price of natural gas below the replacement cost of new gas. In the free market case, gas prices are expected to attain a level approaching parity with oil prices.

Gas prices are projected to increase more rapidly than the other fuels, primarily for five reasons: First, regulation has for years kept the price of natural gas substantially below its market value and below its replacement cost. Second, higher priced supplemental gas, such as high Btu coal gas and LNG, is expected to become a larger proportion of the total supply. Third, assuming price controls are eliminated, then the price of gas is projected to increase to parity with oil prices. Fourth, assuming a continuation of price regulation, the cost of finding and producing domestic reserves will substantially increase as the resource base is depleted. Fifth, gas as a commodity is expected to increase in value relative to other fuels due to limited supplies and premium attributes.

Gas price projections are set out at Chapter III-D of the report. A wide range of uncertainties underlie these gas price projections, reflecting the difficulty in forecasting the cost of finding and producing domestic gas supplies, assessing future prices for supplemental gas supplies, and related factors enumerated above.

The projected consumer gas price for relevant end-use sectors was estimated by adding transportation and distribution costs to the projected national average price of gas. These delivered prices were projected for each of the 17 metropolitan pricing point areas.

14. Future coal prices are projected primarily on the basis of the resource cost, although the demand for high quality metallurgical coal will continue to command "premium" values. Regional variations in the producing environment for coal are substantial and reflected in the price. The varied producing conditions were incorporated into the forecast through high and low productivity projections for each major coal producing region.

Projected coal prices are set out at Chapter III-E of the report. A wide range of uncertainty reflects the difficulty in trying to estimate the regional production costs combined with the effect of world oil prices on the future price of coal, and other factors.

The price of coal in the market will reflect the mine cost plus transportation and market premiums. These latter two factors were both analyzed to estimate the regional prices for the two major coal consuming sectors: electric utility and industrial. In the industrial market the price of metallurgical coal was also projected, where two alternative cases were developed to reflect changes in technology.

15. Cost projections were approximated for coal-based synthetics (high and low Btu gas, and syncrude) based upon data estimated for the present state of technology. The product prices were estimated at the plant gate located in each of the major coal regions in order to reflect the impact of feedstock costs, which in turn were based on the coal price projections. The projections, set out at Chapter III-F of the report, must be considered illustrative since they are based on a relatively immature technological mix. Thus, while the greatest uncertainty surrounds these projections, it is impossible to quantify since the parameters affecting cost have not, as yet, been defined.

16. The range of uncertainty regarding future price levels is far greater for uranium than for conventional fossil fuels. There are numerous unanswered questions with respect to requirements, the size and nature of the resource base, and the costs of the various inputs in uranium exploration and production. Thus, the projections, set out at Chapter III-G of the report, should be considered order of magnitude approximations.

The price projections were tied to the electric energy projections made by EEI, as stipulated by EPRI; i.e., it is estimated that cumulative U_3O_8 requirements from 1976 to 2000 could range from 775 thousand tons under EEI Case C to 2110 thousand tons under EEI Case A. This in turn would require reserve additions ranging from 825 thousand tons to 3360 thousand tons. This extraordinary range in estimates for new uranium supplies underscores the difficulty of estimating future prices.

The projected price of U_3O_8 is primarily developed upon the estimated cost of production. Three alternative estimates of costs were developed. The "low" cost estimate corresponds roughly to the situation which might exist with low uranium requirements, combined with favorable discovery experience. The "high" cost estimate is applicable to the situation where uranium requirements are high (moderate growth, no fast breeder reactor and no plutonium recycle, higher tails assay) and the resource base proves to be relatively unfavorable. The "medium" cost estimate can be considered a scenario of moderate uranium requirements plus a reasonably favorable resource base, or to certain other combinations of requirements and resource base; for example, high requirements and a very favorable resource base.

CHAPTER I

FUEL AND ENERGY PRICE FORECASTS FOR THE UNITED STATES

INTRODUCTION

A. PURPOSE AND OBJECTIVE

Foster Associates, Inc. has undertaken a technical study of fuel and energy prices for the United States over the period 1985 to 2000. The purpose of the study is to provide an input to the Electric Power Research Institute (EPRI) staff with respect to decision making involved in research and development selection.

The objective of the study was to develop constant (1975 dollar) price projections for coal, coal based synthetic fuels, gas, crude oil, petroleum products, and uranium in five-year intervals for the period 1985 to 2000. Each fuel or energy type has been priced out at different levels of commerce (i.e., point of production and point of consumption). This undertaking required an analysis of the cost of production, transportation, and distribution, relevant to the different types of energy. Delivered energy prices were then developed for four major consuming sectors: residential/commercial, industrial, electric utility, and transportation.

B. PROJECTION METHODOLOGY AND LIMITATIONS

A projection of energy prices to the year 2000 is a complex undertaking. In a competitive market the determination of prices is typically the result of simultaneous interactions of supply and demand in numerous different markets. Increasingly, these prices are, directly or indirectly, influenced by non-market factors which may cause them to differ from the level determined in a free market. Predominantly these non-market factors are the result of governmental action. By projecting market and non-market factors over the next 25 years, the complexity is compounded. Thus, the price projections analyzed and set out in this study are directional estimates and are not to be considered definitive.

The procedure used in developing the projections for this study relies primarily on two interrelated approaches -- an empirical analysis of those factors which determine the price of a particular source of energy, and the expert judgment the project team. The projections are not keyed to an econometric model, but rather are built upon a framework of key assumptions followed by empirical analysis plus judgments related to both market and non-market factors. Procedures used to develop the projections are set out in subsequent chapters for each type of energy.

There are limitations and uncertainties involved with any projection methodology. These cannot be overlooked for they contribute to variances in the projection. In attempting to account for the uncertainties encountered in a long-run projection we have endeavored to set out ranges of prices for the different types of energy.

One of the limitations of the projection was the requirement to assume and use given demand cases for both total energy and electricity as developed by the Edison Electric Institute (EEI).* These demand projections are based upon certain economic growth, governmental policy, and price assumptions, which have been evaluated and incorporated in the analysis where relevant; however, there may be inconsistencies with the Foster

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*Economic Growth in the Future, Report of EEI Committee on Economic Growth, Pricing and Energy Use, Edison Electric Institute, 1975.

Associates' projections of supply and price, since these were developed independently. However, an attempt has been made to determine future prices which would be sufficient to elicit supplies to meet the EEI demand forecast.

Another limitation of the analysis has been the exclusion of the price of electricity from the scope of work, in accordance with contract specifications set out by EPRI. This prevented a complete inter-energy price analysis, particularly in the residential/commercial sector.

Another limitation of the analysis is that the price projections for each source of energy are not explicitly linked together in any quantitative manner. Rather a comparison of the individual price projections has been set out for each major end-use sector where judgemental adjustments have been made. Contractual budgetary limitations necessarily precluded further refinements.

C. STRUCTURE OF REPORT

The report is divided into three major analytical chapters. Chapter II sets out major assumptions and parameters which are basic to the projections. Included in this chapter is a discussion of the EEI projections, consuming sector definitions, and pricing points. Chapter III develops and sets out the price projections for each of the major sources of energy. For each of the major sources of energy the analysis discusses projection methodology, supply consideration, cost of production where relevant, and other factors which will determine price. Projections are set out both at the point of production and at the point of consumption. Chapter IV completes the report, comparing the price projections for each energy type within the context of market and non-market factors. This is accomplished through an examination of the supply/demand balance on a national level and through a discussion of energy consumption patterns, along with comparison of the price projection for the relevant fuels in each of the major consuming sectors.

D. PROJECT TEAM

Radford Schantz was project director of this study, and Wayne Mikutowicz was project manager as well as principal analyst and author of sections pertaining to coal and coal-based synthetic fuels. William Foster was assistant project manager as well as principal analyst and author of sections pertaining to gas and domestic petroleum. The section on uranium was prepared under the direction of Celia Star Gody, and the section on world oil under the direction of James Tewksbury. Important contributions to the study were also made by Robert Sarikas, Rose Cammon, Maureen Crandall, George Warholic, and Isobel Bowen.

CHAPTER II

MAJOR ASSUMPTIONS AND PARAMETERS OF PRICE FORECASTS

The focal point of this study is the outlook for energy prices in the United States.

There are a great number of variables or factors which could affect future energy prices. To make clear the circumstances surrounding the forecasts, a number of scenarios were developed, where relevant, to present a range of alternative assumptions. Even with these ranges there are uncertainties surrounding the forecast, which are discussed for the price projections for each fuel.

This chapter first sets out the major assumptions which are relevant to all the price forecasts. Next, the assumptions which are specific to the individual energy price forecasts are discussed. Finally, the parameters of the study such as the types of energy, end-use sector definitions, and the geographic location of purchase are defined.

A. MAJOR ASSUMPTIONS FOR PRICE FORECASTS

The major assumptions related to all the individual price forecasts are listed below:

1. The price forecast was made on a constant (1975) dollar basis.

2. It was stipulated by EPRI that Foster Associates utilize the total energy demand cases and net electric utility generation forecast as developed in the Edison Electric Institute (EEI) report, Economic Growth in the Future, published in June

1975. EEI developed three energy demand scenarios. In each of the cases it was assumed that energy demand will grow at a slower pace than real GNP. Energy supply was assumed by EEI not to restrict the Nation's growth over the long term since the United States possesses adequate energy resources. It was also assumed that consumption patterns for various fuels will shift gradually from oil and gas to coal and nuclear. There was no regional analysis by the EEI. A number of factors were analyzed by EEI to develop the demand forecast. These were: population, agriculture, growth in income, mineral demand and supply, energy supply and demand, conservation and environmental regulations, pricing policy, capital requirements, and international relations.

The following table sets out the major parameters for each of the EEI demand scenarios:

TABLE 1

MAJOR PARAMETERS FOR THE EEI DEMAND SCENARIOS

	GNP Growth	Energy Demand Growth	Population Growth
Case A	4.2%	3.6%	2.5%
Case B	3.5-3.7%	3.0%	2.1%
Case C	2.3%	1.4%	1.8%

Foster Associates has accepted the basic economic assumptions which are inherent in these demand projections. The reader is referred to the EEI study for more details.

3. The following tables show the EEI's forecasts of total energy demand and net electric generation which were assumed for this study:

TABLE 2

EEI TOTAL ENERGY DEMAND CASES
(Trillion Btu)

	Case A	Case B	Case C
1975	76,955	76,955	76,955
1985	115,890	106,889	101,213
2000	186,118	160,858	109,450
Growth rate	3.6%/yr.	3.0%/yr.	1.4%/yr.

TABLE 3

EEI FORECAST OF NET ELECTRIC UTILITY GENERATION
(Trillion Kwh)

	Case A	Case B	Case C
1975	1.98	1.98	1.98
1985	3.63	3.35	3.17
2000	8.08	7.11	5.17
Growth rate	5.8%/yr.	5.3%/yr.	3.9%/yr.

Case B was considered by EEI to represent the most likely conditions for economic growth, energy demand, and electric generation. This study, therefore, utilizes Case B as the "base line" scenario for specific analysis.

4. In general, the U.S. will pursue a path which will seek to lessen the need to rely on foreign sources of energy. It is assumed this will primarily be accomplished through private incentives. In addition, alternate assumptions were tested that the U.S. will pursue an energy policy of either (a) direct controls over supplies and price, or (b) a reduction in the level of direct government influence over energy supply and price with more emphasis on the free market. Each of these scenarios will be considered where relevant to a particular energy source.

5. It is assumed that the U.S. Government will seek to encourage the level of energy research and development and

will also seek to assist in the commercialization of new energy technologies primarily through the private sector.

6. U.S. environmental goals with respect to air quality will continue to be actively pursued over the forecast period. While some variation in compliance dates is possible between 1976 and 1985, it is assumed that all existing sources will be in compliance with air quality regulations by 1985. It is further assumed that over the forecast period control technologies for SO_2 emissions will be commercially available for intermediate and large boiler sizes, and that Intermittent Control Systems (ICS) will not be acceptable as a control strategy.

7. The energy price forecast will only include those taxes which are presently ingrained in the current prices and cannot be excluded (i.e., severance or royalty taxes). Direct taxes such as users or excise taxes will be excluded from the forecast.

B. MAJOR ASSUMPTIONS FOR INDIVIDUAL ENERGY FORECASTS

Major assumptions applicable to the individual fuel or energy forecasts are set out below. These and other minor assumptions are discussed in more detail in Chapter III.

1. Coal

a) There will not be any type of direct government control over coal prices.

b) U.S. energy policy will seek to encourage greater utilization of coal through its replacement of oil and gas as a boiler fuel and through its conversion to gases. This policy will be evolutionary in nature.

c) A program for the leasing of Federal coal lands will be fully established and operational by 1985.

d) Moderately strict surface mine reclamation regulations will be in effect by 1985.

e) By 1985 legislation will be passed that will lay the necessary groundwork for the construction of coal slurry pipelines.

f) U.S. Coal exports will continue throughout the forecast period with little or no government interference.

2. Uranium

a) Government policy will encourage exploration for uranium supplies through research efforts, demonstration projects, etc.

b) There will be no price controls on uranium (U_3O_8).

c) Some form of export controls will be adopted if required in light of the supply situation.

d) A world market price for uranium will develop. Foreign governments will permit exports of uranium subject to maintenance of supply assurance for internal use. It will also be the policy of foreign governments to seek export of enriched uranium rather than uranium feed, wherever possible.

e) There will be no restrictions on importing uranium into the U.S. Also, by 1985 there will be no limitation on enriching foreign uranium for use in domestic reactors.

f) Privately-owned enrichment plants will come into operation, or in any event, the pricing of enrichment services at government-owned plants will move to a commercial basis.

g) There will be no recycling of plutonium prior to 1985. For the period 1985-2000, an investigation was made of two alternative scenarios:

1) Recycling of available plutonium.

2) No recycling of plutonium.

3. Petroleum

a) Domestic

1) Voluntary and mandatory conservation measures will be instituted by the government.

2) There will be no foreign supply disruptions; therefore, the Administration will not implement its safeguard or standby authority to ease the impact of foreign supply cut-off.

3) The Administration will set up the "strategic petroleum reserve" as required by law.

4) Controlled crude oil prices will increase by the maximum allowed by law over a 40-month period. Two price cases will be developed after this time. The first will assume continuing price controls, and the second will assume free market conditions.

5) The "Entitlement Program" will continue if price controls over crude oil persist. This will result in the same geographic and quality price differentials for crude oil as would occur exclusive of price controls.

6) Price controls over petroleum products will be phased out by 1985.

7) The government will moderately encourage the development of synthetic petroleum by the private sector.

8) Outer Continental Shelf development will proceed on an accelerated pace to the early 1980's as proposed by the Bureau of Land Management.

9) The U.S. Government will not be successful in influencing world petroleum prices unilaterally or through cooperation with the International Energy Agency (IEA).

10) Domestic transportation costs will remain constant at 1975 levels.

11) There will be no direct government restriction on imported oil.

b) Foreign

1) OPEC nations will remain unified.

2) OPEC has one major objective -- to keep oil prices as high as possible within certain economic, political and military constraints.

3) The non-OPEC countries who develop export capacity will either join OPEC, or will set their petroleum prices at the prevailing world price.

4) Canada will restrict and eventually eliminate conventional oil exports to the U.S. by the early 1980's. Arctic oil if in surplus of domestic requirements may be developed for export late in the century.

5) The International Energy Agency will not significantly influence world oil prices.

6) There will not be an interruption of supply, or significant price influence from a Middle East War, or for geopolitical reasons.

7) Communist countries will not use petroleum exports in a way which will significantly affect the world price of oil.

4. Gas

a) Domestic

1) Two cases will be assumed with respect to natural gas prices at the wellhead: (a) Federal Power Commission (FPC) regulation will continue without amending the Natural Gas Act, and (b) new interstate gas price will be deregulated.

2) Two cases are assumed for LNG imports: (a) an optimistic case, and (b) a realistic case.

3) FPC will continue to use its current priority categories for curtailing (allocating) natural gas. There will be a nationwide (including intrastate) trend to service the high priority class of residential, commercial, feedstock and direct firing customers -- although some boiler fuel consumption will continue.

4) North Slope gas will commence to be transported to the mainland in the early 1980's.

5) OCS leasing development will be the same as for petroleum.

b) Foreign

1) LNG exports will be priced at world oil parity.

2) Canada will give priority to domestic requirements before exporting gas to the U.S. If Canada has a long-term gas surplus of

appreciable size, it will export to the U.S. to maximize load factor and to achieve balance of payments benefits.

3) MacKenzie Delta and Arctic Island surplus gas will be exported to the U.S., probably after 1985.

4) All Canadian gas exports will be priced at parity with world oil.

C. MAJOR PARAMETERS

The parameters of the forecast were chosen to give a reasonably complete analysis of future energy price structures. The forecast was made at various points of production, major wholesale points, and for end-use sectors.* The end-use sectors were chosen to encompass a large proportion of U.S. energy consumption. The geographic pricing points were determined from major supply areas and major consuming centers.

Set out below are the parameters of this price forecast.

1. 1975 was selected as the base year. The forecast was made for the years 1985, 1990, 1995 and 2000.

2. The projections were made for the following types of fuel and wholesale pricing points.**

Fuel (1)	Pricing Points (2)	Geographic Location (3)
Crude oil	Domestic wellhead	Lower 48 States Alaska
	c.i.f. U.S. ports	East Coast Gulf Coast West Coast
	Refinery Centers	West Coast Oklahoma/Kansas Gulf Coast Great Lakes East Coast

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*End-use sector prices are alternatively referred to in this study as "burner tip" prices.

**Electricity price projections were not included by EPRI as part of the study requirements.

Fuel (1)	Pricing Points (2)	Geographic Location (3)
Petroleum Products	Refinery Centers	Same as Crude Oil
Natural Gas	Wellhead	Domestic U.S.
	Overland imports	U.S./Canadian Border
LNG	c.i.f. U.S. ports	East Coast West Coast
SNG	Plant tailgate	--
Coal	Mine Mouth	Eastern Coal Region Mid-Continent Coal Region Western Coal Region
Oil Shale	Syncrude plant	Colorado
Coal Gas	Plant tailgate	Eastern Mid-Continent Western
Uranium	Mine Mouth	No geographic demarcations
	Fabrication plant	No geographic demarcations

3. The following cities were used as base pricing points for the end-use sector price forecast. At least one city is located in each of the nine census regions. The projected prices should not be taken to represent precisely those cities. However, they represent, more generally, prices for a geographic location with similar characteristics within the same census region.

Census Region	City
New England	Boston
Middle Atlantic	New York Pittsburgh
South Atlantic	Washington, D.C. Charlotte Miami
East South Central	Birmingham
East North Central	Columbus Chicago
West North Central	Minneapolis-St. Paul Kansas City St. Louis
West South Central	Houston
Mountain	Denver Phoenix
Pacific	Los Angeles Seattle

4. The projected prices for the end-use sectors were developed in accordance with the following definitions:

a) Residential -- Price reflects space heating usage. Volumetric determination for each relevant fuel is as follows:

Gas -- based upon seasonal degree days of a particular area;

Distillate -- tank wagon deliveries (less than 500 gallons).

b) Commercial -- Prices based upon small commercial consumption volumes as follows:

Gas -- consumption rate of 70 Mcf per month;

Distillate -- large tank wagon deliveries (greater than 500 gallons).

c) Industrial -- Price based upon large industrial consumption as follows:

Gas -- average consumption rate of 5,000, 15,000 and 45,000 Mcf per month;

Distillate -- truck transport deliveries;

Residual -- truck transport deliveries;

Coal -- volume or multiple rail car shipments.

d) Electric Utilities -- Prices based upon consumption by base load plants burning a particular fuel.

e) Transportation -- Prices based upon regular grade gasoline pump prices excluding Federal and local taxes.

CHAPTER III

PROJECTED PRICES FOR MAJOR SOURCES OF ENERGY

A. INTRODUCTION

The objective of this chapter is to estimate the prices for each major source of energy over the forecast period on a constant dollar basis. The projected prices are developed both at the point of production and at the designated points of consumption for each end-use sector as discussed in Chapter II.

The term price as used in the context of this chapter embodies a wide range of influences depending upon the particular energy source being examined. While in theory, assuming perfectly competitive markets, cost may be discussed synonomously with price; this may not be the case in the real world. Therefore, one must adapt both theory and practice to meet the existing fact structure. This is especially true of energy pricing. A myriad of influences will determine the price structure for any particular energy source or fuel. Each source of energy is at the same time an industry unto itself and part of a larger sector of the economy. This chapter is concerned primarily with the former consideration.

Since price estimation in the future is based upon expectations concerning the future built on the present pricing mechanism, our emphasis here is to start from the actual fact structure which determines current energy prices. Thus, where prices have no relationship to the cost of production, the projection technique focused primarily on those factors other than cost which determine price.

Each major source of energy is analyzed individually in separate sections below. The analysis will include a discussion of those factors which will influence the price of the different types of energy over the forecast period, a description of the projection approach, and finally the price projections of the relevant pricing points on a constant dollar basis, together with an estimation of the range of uncertainty attending the forecast.

B. WORLD OIL

1. Introduction

While the focus of this study is on energy prices in the United States, the price of world oil has, since 1974, had a strong influence on these prices, and for two reasons. First, the quantum leap in OPEC oil prices in 1974 was far above costs of production, and above energy prices in the U.S. Second, the U.S. has increasingly been required to import world oil because of declining oil and gas production. Given this compounding set of factors, the price of world oil has definitely influenced the structure of energy prices in the U.S. and this influence is projected to continue into the future.

Thus, the projection of world oil prices is important to this study. Yet, being a "value" price determined by a producer cartel, the uncertainty of these forecasts is greater than what it would have been otherwise.

A forecast of ocean-going tanker transportation costs is set out, again attended by considerable uncertainty which has always been the case for this element of world oil prices.

2. Foreign Oil Price Projections

a) Introduction

In the coming quarter century, foreign oil prices are expected to be determined by a number of different major influences which vary substantially in importance with time. Therefore, a single forecasting approach is not suitable over such a long period.

In broadest terms, early in the period prices are expected to be influenced primarily by non supply-demand factors; i.e., by OPEC, which in turn is constrained mainly by still other non supply-demand factors. Later in the period, more conventional supply-demand factors are expected to take over.

Some of the influences on foreign oil price to the year 2000 are presented in Schedule III-B-1, where the number of X's portrays the relative importance. These factors are discussed in detail in the section which follows. Next, a forecast of the price of Saudi Arabian light crude oil, the generally accepted marker, is given. Then, possible variations from this forecast are discussed. Then, for references and background, some forecasts of others are summarized and a brief history of OPEC is presented.

b) Non Supply-Demand Influences

As shown in Schedule III-B-1, non supply-demand influences are projected to continue dominating foreign oil price for at least the next five years, and to remain important or significant through the rest of the period.

The recent upward influence of OPEC on world oil prices is, of course, well known. OPEC will probably continue to have a dominant influence for at least five years, in spite of suggestions by some authorities that OPEC is about to break up. OPEC easily weathered probably the worst crisis it is likely to see for a while in maintaining prices in the summer of 1975, when a severe worldwide recession cut back oil consumption sharply and oil stocks were high from an unusually warm winter.

Nor should one be misled by the current controversy over oil quality differentials (see OPEC history, below, for details) -- this is not a new problem and it has not eroded and will not likely erode the general level of OPEC oil prices. One should also not underestimate what the experience of the current high prices has done to solidify OPEC. Certainly, OPEC is made up of widely diverse elements which have not gotten along well in the past. However, there is a big difference between squabbling over how to achieve a goal for which there is no precedent, and maintaining the huge new source of national income which high prices provide. OPEC has not even had to try any sort of production control yet, even in the summer of 1975, and one can be sure a major and likely successful effort would be made in this direction if any major erosion in price were to start.

The non supply-demand factors creating a downward influence on OPEC oil prices are much less well known and often ignored, but are important. Without these factors, OPEC would probably increase prices much more. These factors are influences of a somewhat intertwined political, military and financial nature, including:

- Concern of possible Russian military and/or political intervention in Middle East countries, including Iran. This is a very real deterrent to higher prices which might severely strain the political relations and/or economies of the U.S. and other developed countries with the Middle East countries.
- Concern by a number of OPEC countries of each other militarily. These countries partly rely on the U.S. and others to protect them, hence, do not want to be the country that encourages oil prices that are much too high.
- Concern of direct military intervention by consuming countries. This has certainly entered the thinking of some OPEC countries, and therefore acts as a ceiling, albeit a high one, on oil prices.
- For Arab countries, fear of and hatred for Israel, yet respect for policies of the U.S. and other countries toward Israel.
- Concern of inflation and/or world recession from excessive oil prices which would erode real value of payments for oil faster than prices can be raised.
- Worry of economic pressure from the U.S. and others, especially through food exports which are important to many OPEC countries.

It is particularly interesting to note that the aggregate of the above constraints, plus the fear of new energy counter-measures by consumers discussed in the next section, appear to be holding foreign prices in a state of near equilibrium (in real terms), which should continue for awhile. In spite of all the dire predictions of world economic disaster and the energy counter-measures which would result from high oil prices, very little counter-measures have actually materialized. Of course, the high oil prices did contribute to the 1975 world recession and have caused an extraordinary burden on underdeveloped countries. Yet, one can sense a strong, but perhaps not explicitly stated, feeling in OPEC that they have achieved high gains without too many problems; and do not want to risk losing these gains by trying to get too much more. Obviously, as OPEC influence ebbs, these influences will become less relevant.

There are also non supply-demand factors which create an "upward" influence on oil prices in OPEC. For example, the two countries with the largest oil reserves in the world -- Saudi Arabia and Kuwait -- as well as some other OPEC countries with large reserves, do not need or even want too much oil income at this time. This tends to restrain production, which is in turn an upward influence on price. These countries are concerned about poor investments and other problems resulting from receiving too much money too fast, and prefer keeping oil in the ground as an investment. Along the same lines, most OPEC countries are now fully cognizant of the finite nature of their resources, so are trying to get the most per barrel they can. None appear to subscribe to the sometimes propounded idea of unilaterally maximizing total oil revenues by cutting prices to increase volume. These upward influences on OPEC are likely to continue to be significant as long as OPEC influences prices.

c) Supply-Demand Influences

As shown on Schedule III-B-1, there are some supply-demand influences on foreign price now, more in the next 5 to 10 years, and ultimately this type of influence is expected to dominate.

Currently, the most important supply-demand factor is the concern of new supply and demand counter-measures which a higher OPEC real price might trigger. This particular influence is different from most other supply-demand influences in that it is only a threat rather than a certainty, and OPEC may choose to ignore it over the short term if they desire. As discussed earlier, this and other non supply-demand constraints on OPEC appear to be holding foreign prices in a state of near equilibrium in real terms.

Another supply-demand downward influence which is significant now, and will become more important, is the pressure resulting from the effect of the very sharp rise in price which occurred during the embargo. Both supply and demand are involved. Substantial new oil supply has resulted and will result from the high prices, and much of this supply will be developed outside of OPEC as consumers strive for self-sufficiency. World oil demand has been and will continue to be substantially less as a result of high prices, both due to price elasticity of demand and conservation efforts by consuming countries. The combined effect will continue to be a downward influence, or at least a strong stabilizing pressure on OPEC prices.

A third supply-demand influence is the increasing cost of new supply as we approach the year 2000. This is coupled with the fact that most of the proven reserves now in place in the world will be depleted by the year 2000, even at only about 2-3 percent increase in production per year. Current (1975) proven reserves were

659 billion barrels; 1975 production was near 20 billion barrels (both from Oil and Gas Journal). Thus, essentially all the cheap supply will be gone and likely replaced with much more costly supply such as the North Sea and Arctic supplies. Good examples of increasing costs are given elsewhere in this report for shale oil and new conventional oil in the United States -- both rise to high levels by the year 2000, and the foreign price projections trend toward these levels as we approach 2000.

The fourth supply-demand influence on price will be the likely developing scarcity of oil as we approach the year 2000. This will probably be a psychological influence at first, but will likely become quite real near the turn of the century. Sometime approaching 2000, the dominance of oil in the energy picture will shift, and oil will be used more and more only where there is no substitute; i.e., in transportation and chemicals, while heating and power generation will be increasingly replaced by other energy sources.

Intrinsic to the foreign oil forecast is the independence of oil from other energy prices. Early in the forecast period, OPEC prices will dominate, and the largely unsubstitutable nature of oil products eliminates most influence from other energy prices. Then, late in the forecast period, climbing price and cost trends will tend to minimize the price interaction with other types of energy.

d) Foreign Oil Price Projections

Combining the influences indicated above, foreign oil prices are projected in terms of the generally accepted marker crude, Saudi Arabian light, FOB Saudi Arabia, as set out in Table 1 (in constant 1975 dollars per barrel).

TABLE 1

WORLD CRUDE OIL PRICE PROJECTION

	Base Case	Low Case	High Case	Range of Uncertainty
1976	$11.10	$11.10	$11.10	--
1985	10.00	4.00	15.00	375%
1990	11.00	6.00	17.00	283%
1995	13.00	8.00	19.00	238%
2000	16.75	11.00	22.00	200%

The base case corresponds to about a 10 percent price drop between 1976 and 1985, about a 2 percent per year growth between 1985 and 1990, about 3-1/2 percent per year growth between 1990 and 1995, and about 5 percent growth from 1995 to 2000. The high and low cases are discussed at the end of the next section.

The above forecast, of course, assumes that essentially a single price structure will continue in the foreign area in each of the three cases.

e) Range of Uncertainty in Projected Prices

Given the vast and uncertain economic and geopolitical interplay among the countries of the world, a wide range of uncertainty attends the world oil price forecast -- a range as great as 375 percent in 1985. Some of the reasons for this range are set out below.

During the next 10 years, as long as OPEC supplies remain dominant, foreign oil prices are particularly subject to variation, both up or down. A very large downward variation from the forecast could occur if the OPEC cartel were to break up as producing costs are much lower than price, and because reserves and producibility are high relative to consumption. It is not probable that OPEC will break up, but the right combination of very low consumption and internal OPEC strife could cause a breakup.

On the other hand, substantially higher prices are also possible over the next 10 years if OPEC chooses to ignore the restraints on price. Such an action might well be followed by a sharp price drop resulting from the effect of high prices on consumption and retaliation to the high prices by the U.S. and other consumers.

Contributing materially to variability in the early years is uncertainty in U.S. energy policy. Presently, as the energy crisis has ebbed, so apparently has the interest in energy self-sufficiency. In turn, the possible influence of U.S. self-sufficiency on world prices has ebbed. A new energy crisis, created perhaps by another foreign supply cutback, or from mounting balance of payments problems resulting from paying for imported oil, could quickly and sharply end U.S. apathy; and if the crisis were severe enough, could even lead to breaking OPEC's hold on price.

Later in the forecast period, less variation is projected. Costs, at least for newly discovered oil, such as that in the North Sea and in the Arctic, will be much closer to prevailing prices; and therefore, more conventional supply-demand influences, which are less variable, are likely to dominate. By the year 2000, most crude oil supplies will likely be high in cost and much will be outside OPEC. Of course, it is always possible that huge new reserves of cheap oil will be found, but this seems unlikely in the present state of technology and extent of exploration. And, of course, it is also possible that new discoveries will be fewer and costs much higher than expected at this time.

Throughout the forecast period, there is uncertainty in the forecast resulting from the still evolving impact of the 1974 quantum leap in world oil prices on longer term oil supply and demand. During the two and one-half years since the large increase, even the short-term effect has been very much obscured by the severe worldwide economic recession.

The high and low cases given in the last section are an approximate quantitative representation of the above possible variations. The low case in 1985 represents a near total collapse of cartel pricing by OPEC. Even so, the low case price in 1985 would still be well above cost because enough countries like Saudi Arabia, Kuwait and Libya who do not need the current income would unilaterally cut production sharply rather than sell at prices that were much lower than current levels. After 1985, the low case reflects the consequence of new reserves (and/or alternates) being at a much lower cost than anticipated.

The high case price in 1985 reflects what might happen if OPEC ignored the restraints on price previously discussed. The high case prices after 1985 could occur if new reserves (and/or alternates) are at a much higher cost than anticipated. A sustained very high real price of oil such as shown in the high case is quite unlikely, for example, because such a high price in 1985 likely would bring out enough new energy supply, cut demand enough, and/or trigger enough other counter-measures by consumers to bring price down again.

f) Forecasts of Others

There have been several forecasts of foreign oil price subsequent to the embargo which have been surveyed. The basic approach in these forecasts is probably of more interest than the price level *per se* because most did not project to the year 2000.

Most projections were for 5 to 10 years, and most assumed only a single major influence to dominate. The following classifications of forecast approach are suggested by this survey:

- A. U.S. Price Level Dominates
  - 1. U.S. Self Sufficiency Price Controls
  - 2. U.S. "Unconventional" Oil Price Controls
- B. Foreign Price Level Dominates
  - 1. OPEC Stays Strong
    - a) Real price up
    - b) Real price constant
    - c) Real price down
  - 2. OPEC Weakens
    - a) Maximizes revenues rather than price
    - b) Other
  - 3. OPEC Collapses

Schedule III-B-2 gives the data published, author, approach (per above), price forecast, dollar bases (current or constant dollars), and reference to the forecasts which were surveyed. Forecasts are arranged in order of date published, with the latest given first. Type of crude and location is not usually specified, but most likely is Saudi Arabian Light, FOB Persian Gulf. No forecasts dated prior to 1974 are included because none prior to the sharp embargo price increases are meaningful.

g) Brief History of OPEC

OPEC, the Organization of Petroleum Exporting Countries, is so important in the recent history of foreign oil prices and in the study forecast that a brief history of OPEC is included, although the scope of this study precludes an in-depth analysis. Some other key related foreign price developments are also given.

Schedule III-B-3 summarizes estimated foreign oil price (Arabian Light at the Persian Gulf) since World War II in current dollars and in 1975 dollars. Schedule III-B-3 also shows "take," which is simply the host government's share of revenues from oil. "Take," because it has become such a large part of total price, strongly influences price. Schedule III-B-3 also gives posted price. For the purpose of this study, this is not a particularly useful figure. Initially it was a true "posting" or offering price, which was generally higher than the actual market price. Then, it became a basis for a somewhat complex calculation of take; i.e., it became the "tax reference price," and as such usually had little meaning in terms of actual market price. More recently, the meaning again shifted, with market price for certain transactions as a fixed percentage of posting. Presently, OPEC essentially states what the price of Saudi Arabian Light will be for direct sales by Saudi Arabia, which sets a practical ceiling on what companies can charge; and states what crude oil will cost companies who formerly owned it, which is a floor that prices are not likely to drop below.

From the late 1940's to about 1957, "take" increased. Then, though, take declined as a result of declining posted prices upon which take was based. This led the major producing countries to band together to counter the decline by forming OPEC in 1960. Initially, there were five members -- Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela. This list still includes those with the largest oil reserves or reserve potential, but the total membership has expanded to thirteen.

OPEC was eventually able to check the decline in postings, and achieve some other small victories, but was unable to make major gains in take throughout the 1960's in spite of considerable effort in this direction.

In part, the politics, religion, and needs of different OPEC countries were so different that they were unable to work effectively in concert even though the stakes were very large.

In 1967, the first event occurred which would eventually create the climate for substantial increases in host country take. Most foreign crude oil reserves and productive capacity, then and now, are located in the Persian Gulf, and there are only limited pipeline facilities to move oil from the Persian Gulf to the Mediterranean. Therefore, the closing of the Suez Canal in 1967 forced more crude oil to take the long route around Africa, which brought on a tanker shortage. The tanker shortage was then severely aggravated in May 1970, by the closing of Tapline from Saudi Arabia to the Mediterranean. Tapline could carry up to one half million barrels a day of oil, and its closing required that up to this amount go around Africa. Tapline was not reopened for many months, which sent tanker rates skyrocketing. After six months of unsuccessful negotiations to increase take, in June 1970 Libya ordered sharp cutbacks in crude production. Since, of course, Libyan crude oil is "short-haul" to market, i.e., on the Mediterranean, this further strained tanker capacity. The remaining Libyan oil then, of course, sold at a large premium, which prompted Libya to demand a large share. Libya succeeded in September 1970 in this regard because consumers had no viable alternative to Libyan oil. Next, Venezuela in December 1970, also increased take, again because consumers had no viable alternative.

Up to this time, OPEC had not as a group achieved major results counter to existing market conditions. Then, in December 1970, OPEC issued Resolution XXI-120, demanding increases in take and greater uniformity in take. Largely as a result of this resolution, in February 1971 the famous Teheran agreement raised take substantially (see Schedule III-B-3) for Persian Gulf countries. The Persian Gulf was not in the same strong, independent bargaining position that characterized Libya -- oil was in plentiful supply, there was limited access to market due to the tanker shortage, and Persian Gulf oil is generally high sulfur compared to the more desirable low sulfur content of African crude oil. This was the real beginning of OPEC power -- a major gain counter to economic conditions, i.e., a successful cartel action.

The Libyans next said that if Persian Gulf countries got more, they should get even more. This was achieved in April 1971 with the Tripoli agreement. Persian Gulf countries did not "leapfrog" another increase in take this time, as both they and Libya had signed 5-year agreements at the time of the early 1971 increases, which fixed future take including some escalation. Most informed observers at the time did not expect OPEC to abide by these 5-year agreements for long. It was a surprise, however, that they only lasted until January 1972, when the first Geneva agreement superseded them. Another agreement in Geneva in June 1973 further increased prices.

Bargaining began again in October 1973 as market price rose above posted price, and OPEC wanted to share this increase in profits. The start of the 1973 Arab-Israeli War terminated this bargaining.

Up to this time, the increases in "take," and consequently in price, had been substantial, as is shown in Schedule III-B-3. The quantum leap for OPEC was yet to come, however. The Arab oil embargo of the U.S. and the Netherlands, coupled with a cutback in production to reduce "cheating" on the embargo, provided the shortage climate which permitted the spectacular increases in price and take in early 1974. Prices and take then continued to increase more moderately until the present, more or less following inflation in cost of goods imported by oil producing countries.

Particularly noteworthy in the post-embargo years was the summer of 1975, when world oil consumption was down sharply due to severe, worldwide recession, and stocks were unusually high following an unusually warm winter. During this period, OPEC countries generally reduced oil output, and reduced it enough to weather this worst strain on high prices since the embargo. Remarkably, output was sufficiently reduced without any formal production controls or market sharing arrangements. The strength and unity of OPEC was thus confirmed, with all that this implies for the future.

Another controversy within OPEC is still unresolved -- that of price differentials between different countries' crude based on sulfur content, gravity and location. OPEC basically has only set the price of Saudi Arabian Light "marker" crude oil at the Persian Gulf, with the rest left to adjust as they will. This has led to considerable controversy between some OPEC countries, which in turn has perhaps misled some observers into thinking that OPEC is about to collapse. However, this problem is not considered to be as serious as that of the summer of 1975, which OPEC weathered with hardly a ripple.

Still another important recent influence has been "participation," which is in essence partial or total transfer of ownership of oil operation in host countries from oil companies to the host countries. All the results that this could have on price are not in --

so far, the oil companies still refine and market most OPEC oil. There are substantial quantities of oil now marketed directly by OPEC, though, and this apparently has not yet had a significant effect on the OPEC oil price.

As a reaction to the OPEC price increases and the Arab embargo, there has been considerable dialogue and effort on the part of major oil consuming countries to counter these problems in concert. So far, these efforts have not been significantly productive, and there is little reason to think this will change soon, if at all. The interests of the consuming countries seem to be too diverse and nationalism too strong for them to work together on this complex and important problem.

Thus, the history of OPEC as it relates to price has been first, a long period of being relatively ineffective; then a jump to real power in 1971 with the Teheran agreement; another jump to great prosperity and even greater power as a result of the Arab oil embargo; and finally, a continuing viselike grip on this great prosperity and power in spite of possibly divisive problems.

3. Tanker Transportation Costs

Tanker transportation costs from the Persian Gulf to the U.S. are projected as set out in Table 2.

TABLE 2

PROJECTED TANKER COST

	Cost , $/Bbl.	Range of Uncertainty
1975 (Actual*)	1.74	-50%, +100%
1985	1.75	-50%, +100%
1990	1.75	-50%, +100%
1995	1.75	-50%, +100%
2000	1.75	-50%, +100%

---

*AFRA rates for LR-1 size tankers (45-80,000 DWT) from Petroleum Economist. These are the largest now able to serve the U.S.

A number of influences combine in this forecast. Tending to push costs up early in the forecast period will be some easing of the current severe surplus of tankers, and later in the period rising fuel costs. Tending to push costs down will be increasing size of tankers able to serve the U.S. resulting from construction of deepwater ports and transshipment from larger tankers in the Caribbean and perhaps Canada. Also tending to push costs down will be the shortening of the distance traveled as the Suez Canal is widened and deepened, and/or more pipeline capacity connects the Persian Gulf to the Mediterranean.

Although the current severe surplus of tankers is likely to ease somewhat, there will probably be a continuing excess of tankers throughout the forecast period. Producing countries are moving more and more into shipping their own crude; and to the extent that this results in new building, it will contribute to the surplus. Many tankers are now in layup, and others are "slow steaming" to reduce fuel cost, providing a reservoir of extra capacity which will last many years. Reduced consumption of oil, resulting from high prices and conservation, will tend to keep tanker needs down. Increased refining in producing countries could result in more, smaller product tankers being built. And, of course, widening and deepening Suez and more pipeline capacity connecting the

Persian Gulf and the Mediterranean will reduce tanker needs.

The possible variation from the above projections is substantial in both directions. The tanker market traditionally is extremely competitive and volatile, and rates even over the long term are very sensitive to these competitive conditions. Tanker rates have in the past remained for considerable periods both well above and well below actual costs. An extended worldwide economic boom which increases oil consumption can easily push rates up, and conversely, another worldwide recession can push rates down sharply. Another factor which could substantially increase costs to the U.S. would be a law requiring part of the U.S. oil imports to be carried in U.S. flag tankers. The forecast in this study assumes there would be no such laws, but such a law is quite possible. In fact, just recently Congress passed a bill to this effect, but did not override a Presidential veto.

In summary, the uncertainty of future tanker costs is as great as any cost/price forecast in this study, especially in the short run.

C. U. S. PETROLEUM

1. Introduction

Future U.S. petroleum prices were analyzed at three levels -- at the production level, at the refinery, and delivered to the ultimate consumer.

At the production level, two general cases were analyzed -- a price control case and a free market case. In the price control case, it was assumed that the Government will keep the average domestic crude oil price below the cost of new crude oil and below world oil prices. In the free market case, it was assumed that domestic crude oil prices will equate to delivered foreign crude oil prices after adjusting for quality differences.

Refinery feedstock is a blend of domestic and foreign crude oil. The price of domestic feedstock is the price at the production level, plus the estimated cost of transportation to the refinery. The price of foreign feedstock to refineries is the basic price projected in the Foreign Oil Price section of this report (Chapter III-B); plus tanker transportation to the United States (also in that section); plus, for inland points, estimated cost of internal United States transportation. Then, refinery margins were added to estimate products prices at the refinery.

Finally, prices at the consumer level were estimated by adding transportation and distribution cost to product prices at the refinery.

The first section of the domestic petroleum price forecast deals with the future U.S. petroleum supply and demand outlook. The remaining three sections describe in detail the price forecast. These cover the price of domestic crude oil under price controls, the price of domestic crude oil under free market conditions, and development of consumer prices under both cases.

2. U.S. Supply and Demand for Petroleum

Future domestic petroleum supplies will come from several sources: conventional production from the Lower 48 States (by primary and secondary recovery methods); Alaskan oil; shale oil; and oil produced by tertiary recovery techniques. The price of crude oil from each of these sources may differ. Therefore, it is important to evaluate each prospective source of supply.

The Department of the Interior (Geological Survey) has estimated U.S. crude oil reserves under different categories. These reserves are the present and potential resource base from which future U.S. crude oil will be produced. The reserves are set out in Table 1 on the following page.

The most certain category is the "demonstrated" reserves, which include 39 billion barrels. These are proven API reserves plus indicated estimates. Most of these are located in West Texas, East New Mexico, the West Gulf Basin, and Alaska (North Slope).

The "inferred" reserves are more speculative. These reserves are made up partly of revisions of current estimated reserves and partly of "undiscovered" oil from future extensions and new pools in known fields. Total U.S. "inferred" reserves are estimated at 23 billion barrels. These reserves are essentially located in the same areas as the proven reserves.

Even more speculative than the "inferred" reserves are the "undiscovered" reserves. These reserves have not been discovered; however, there is some probability of discovery in the future. The total reserves in this category are 82 billion barrels. Most of these are located onshore in the Lower 48 States. In addition, there is some indication of other Alaskan finds the size of the North Slope, both onshore and offshore.

TABLE 1

MEASURED AND POTENTIAL U.S. CRUDE OIL RESOURCE ESTIMATES

(Billion barrels)

	Demonstrated (Measured & Indicated) (1)	Inferred (2)	Undiscovered (3)	Sub-Economical	
				Identified (4)	Undiscovered (5)
Lower 48 States - onshore					
Pacific Coast	4	Nil	7	--	--
W. Texas & New Mexico	9	2	8	--	--
Western Gulf Basin	8	9	8	--	--
Other	4	3	21[a]	--	--
Total	25	14	44	--	--
Lower 48 States - offshore					
Pacific Coast	1	Nil	3	--	--
Gulf of Mexico	2	2	5	--	--
Atlantic Coast	0	0	3	--	--
Total	3	3	11	--	--
Alaska - onshore	10	6	12	--	--
Alaska - offshore	Nil	Nil	15	--	--
Total U.S.	39	23	82	120-140	44-111

[a] Mid Continent - 6 and Northern Rocky Mountain - 7.

Source: Department of the Interior (Geological Survey) Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, 1975.

The "Sub-Economic" category will require technological advances in enhanced recovery techniques to be realized. The historical recovery factor has averaged 32 percent. As the relative economics change over time reserves from this category will become available.

The U.S. Geological Survey (USGS) estimates natural gas liquid reserves in the same categories, except for "uneconomical." These are: proved reserves - 6 billion; inferred reserves - 6 billion; and undiscovered reserves - 16 billion.

The USGS reserve estimates for all categories are based on historical trends in experiences and technological changes to 1974, and the pre-1974 price-cost relationship. To the extent that future situations differ significantly from past trends, these reserve estimates would change. The pre-1974 price-cost relationship is not valid today. While higher crude prices are likely to increase U.S. reserves from the indicated levels, U.S. price controls, on the other hand, probably keep the reserves below the potential level.

Petroleum from shale oil is another potential supply of U.S. energy. It has been estimated by the Department of the Interior and the National Petroleum Council that U.S. shale oil reserves may be as large as 400-600 billion barrels; however, only 50-80 billion barrels may be commercially recoverable. There is no commercially acceptable process to produce oil from shale oil at this time. At least some commercialization of shale oil is expected during the forecasted period.

The projected supply used in this study from each of these sources, in million barrels per day (MMBD) is shown on Table 2.

TABLE 2

PETROLEUM SUPPLY PROJECTION MMBD

	1975	1985	1990	1995	2000
Conventional Lower 48[1]	8.4[2]	8.0	7.3	6.6	6.0
Alaska (North Slope)	-	2.0	4.0	4.0	3.8
Shale Oil	-	.3	.8	1.4	2.0
Tertiary Recovery	-	.6	1.0	1.6	2.3
Total	8.4	10.9	13.1	13.6	14.1

1/ Primary and secondary oil. Excludes NGL of about 1.6 MMBD. And, includes South Alaska.

2/ Source: Bureau of Mines (includes South Alaska and some tertiary).

The above forecast shows conventional Lower 48 States production dropping from the 1975 levels of 8.4 MMBD to 6.0 MMBD by 2000. This results primarily from an expected decline of onshore production. Offshore production is projected to increase to the mid-1980's and then level off before slightly declining. The projected decline in Lower 48 production is based on the assumptions used to develop the price forecast. First, the price forecast is based on a 15 percent discounted cash flow rate of return. A sustained rate of return at this level is expected to provide sufficient incentive to increase well drilling over the forecast period. Second, the price forecast assumes a constant productivity rate (constant number of barrels found per foot of successful wells drilled). Third, the price forecast assumes a declining success ratio (ratio of successful wells to total drilled). The rising drilling rate is expected to roughly offset this declining success ratio. Thus, reserve additions are projected to remain approximately constant through the period, at about the current level of just under 6 MMBD. And, finally, the projection assumes production levels will approach this reserve addition level by the year 2000.

No distinction was made in the supply forecast between the price control case and the free market case. There is no doubt that larger domestic petroleum supplies would result from the higher prices projected for the free market case. However, there is not sufficient certainty of this volumetric difference to justify quantifying the different supply levels given budgetary constraints attending the study, and given the wide range of uncertainty in the price forecasts. Therefore, the conventional domestic supply forecast for the Lower 48 is a blend of both cases.

The 1985 shale oil figure is a nominal amount only, representing the start of commercial production. Even this level may be optimistic. By the year 2000, shale oil production may increase significantly if environmental, technological, and price constraints are overcome. If any of the constraints are not overcome, the shale oil volumes are optimistic. Oil recovered through tertiary methods is projected to be economical by 1985 and grow in importance by the year 2000. Lastly, North Alaskan oil will be delivered to the Lower 48 by the late 1970's. The initial pipeline capacity is 2 MMBD. It is assumed that this line will be expanded to 4 MMBD by 1990 to transport Naval Petroleum Reserve No. 4 and other undiscovered North Alaskan oil.

The petroleum demand forecast prepared by the Edison Electric Institute* is presented in Table 3 to compare with the supply estimates.

TABLE 3

EEI DEMAND FORECAST
MMBD

	1975 (Actual)	1985	2000
Case A	16.3	23.4	31.1
Case B	16.3	21.6	26.5
Case C	16.3	20.4	18.7

A comparison between supply and demand cannot be made until natural gas liquids (NGL) production is added to the

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*EEI, Economic Growth in the Future, June 1975.

supply forecast. In 1975 NGL production was about 1.6 MMBD. Optimistically assuming this level will continue for the projected period, then the proportion of domestic petroleum production which will make up future U.S. demand can be estimated. These proportions are set out in Table 4.

TABLE 4

PROPORTION OF U.S. PETROLEUM DEMAND SUPPLIED DOMESTICALLY

EEI Demand	1975	1985	2000
Case A	61%	53%	50%
Case B	61%	58%	59%
Case C	61%	61%	84%

3. Projected Price and Cost of U.S. Crude Oil Under Price Controls

The projected price of domestic crude oil from each supply source under price controls is summarized on Table 5.

TABLE 5

$/Barrel (1975 Dollars)

	1985	1990	1995	2000
Conventional Lower 48 (Wellhead)				
Price	$9.99	$11.59	$12.80	$14.13
(Incremental Cost)	$11.39	$12.68	$13.80	$15.00
Alaska (FOB Lower 48 States)				
Price	$12.30	$13.30	$14.00	$15.00
Shale Oil (FOB Syncrude Plant) (Excludes lease bonuses and land costs)				
Price	$13.88	$14.44	$15.02	$15.64
Tertiary (Wellhead)				
Price	$15.75	$16.45	$17.41	$18.19

a) Projected Price for Conventional Lower 48 States Crude Oil Under Price Controls

In 1975 the U.S. Government enacted the Energy Policy and Conservation Act (EPCA) which, among other things, fixed the average price of domestic crude oil at $7.66 per barrel for 1976. Further, EPCA -- (1) would allow this price to increase 3 percent per year in real terms, assuming it can be demonstrated that such an increase is needed to provide incentives for domestic exploration; and (2) would allow price controls to expire in 40 months. It is assumed in this part of the study that the 3 percent annual increase to 1990 and 2 percent annual increase from 1990 to 2000 will be justified, as discussed below, and that price controls will extend to 2000.*

Further, it was assumed that price controls would continue to operate essentially as they do now; i.e., they would hold the average price below the incremental cost of new supply, and would have one or more higher price tiers for "new" oil. Thus, the approach was to project the average (controlled) price on the same basis as in the EPCA formula, increasing at 3 percent per year in real terms to 1990 and at 2 percent per year to 2000. Then, to provide an alternate case, a cost forecast was made for new oil. This calculation showed that costs as calculated ran $1-2 per barrel over the average, which is consistent with the present relationship of the allowed price of new oil compared to the average (of new and old). Thus, the 3 percent and then 2 percent real rise in the average price of crude oil appears to be a reasonable basis for the price control case. The projected cost of new crude oil was therefore used as a barometer to the price forecast of the average cost of crude oil under price controls.

Set out below in Table 6 are the estimated price ceilings to the end of the 40-month period which are

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*See below for the alternate assumption that price controls will expire in 1979.

projected to the year 2000, assuming a 3 percent increase to 1990 and a 2 percent increase to 2000. As a comparison, the projected cost of "new" domestic crude (developed in a subsequent section) is also shown in the table.

TABLE 6

$/Barrel (1975 Dollars)

	Price Projection	Projected Cost of New Crude Oil
2/76[1/]	$7.66	$8.81[2/]
2/79	$8.44	$9.28[3/]
1985	$9.99	$11.39
1990	$11.59	$12.68
1995	$12.80	$13.81
2000	$14.13	$15.00

1/ Established by the Energy Policy and Conservation Act.

2/ 1975.

3/ 1980.

b) Projected Cost of New Conventional Crude Oil (Lower 48 States)

There is no authoritative methodology for determining the future cost of "new" crude oil.* Therefore, a discounted cash flow (DCF) approach has been used based on methodology developed at the FPC regarding the cost of "new" natural gas (See Chapter III-D). The method is relatively complex and required a number of approximations. While not precise, it is useful as a guide to what might constitute a regulated cost-controlled forecast for an incremental barrel of crude oil produced in the Lower 48 States.

In essence, the method separately forecasts the different cost components such as drilling costs, lease acquisition costs, operating costs, and carrying charges,

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*However, the National Petroleum Council covered this question in the U.S. Energy Outlook, 1972.

and based on a DCF calculation determines the required price at an internal rate of return of 15 percent. Information was not available as to the costs for recompletion and deeper drilling, therefore, these costs were excluded from the calculation.

Schedule III-C-1 sets out the projected Lower 48 cost for new oil for every fifth year, 1985 to 2000. Each cost component shown on the schedule was projected in total dollars and then divided by an estimated productivity factor to put it on a dollars-per-barrel basis:*

Line 1 - Successful Oil Well Costs

The cost of successful wells is the cost per foot drilled for successful oil wells with a one-year lag divided by the productivity factor.

The productivity factor is the most sensitive variable in the forecast. Schedule III-C-2 sets out the oil reserve additions per foot drilled from 1950 to 1974 for the Lower 48 States. A 5-year moving average of reserve additions was used to moderate the considerable year to year fluctuation. There is a slight increase in productivity from the middle 1950's to the late 1960's, averaging 1.5 percent per year. The primary causes of this rise included -- (1) the increasing proportion of offshore drilling in which at the outset the productivity was substantially higher; and (2) the substantial amount of oil which has been classified as recoverable under secondary recovery methods.

An optimistic productivity factor of 43.0 barrels per foot drilled was assumed in this study. It is

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*Productivity is defined as reserves added per foot of successful oil wells drilled.

expected that secondary recovery methods will not continue to have an important impact on productivity.[*] Furthermore, the productivity of offshore drilling might decline as drilling evolves to deeper and more inaccessible waters and terrains.

The cost per foot drilled for successful oil wells was based on data reported by the Joint Association Survey (JAS) sponsored by the American Petroleum Institute, Independent Petroleum Association of America, and the Mid-Continent Oil and Gas Association. The data are set out separately for onshore and offshore drilling in Schedule III-C-3.

Columns 1 and 2 of Schedule III-C-3 set out the cost per foot drilled in current dollars. Column 3, the GNP price deflator, is used to convert these costs to 1975 dollars, as shown in Columns 4 and 5. There has been an increase in drilling costs in constant dollars for both onshore and offshore drilling, especially in recent years. This is partly due to an increase in the average well depth for onshore wells as shown on Schedule III-C-4. This, in turn, reflects the fact that the deeper the well, the cost per well and the cost per foot drilled increase substantially. (See Schedule III-C-5.) For example, after passing the depth interval of 3750-4999 feet, the average cost per foot drilled, at 2500 feet intervals, increases by an average of 36 percent for onshore. Offshore costs are markedly greater at depths of 5000 feet or more.

The costs per foot drilled in constant dollars (Columns 4 and 5 of Schedule III-C-3) were used to calculate a linear regression line to project future drilling costs. It is therefore assumed that the

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[*] Tertiary recovery of oil is analyzed separately in this study and therefore is not relevant here.

historical trend in drilling costs will extend into the future. Onshore and offshore drilling costs were projected separately and then averaged together. The projected costs are shown on Sheet 2 of Schedule III-C-3 and averaged on the basis of an estimate made by the National Petroleum Council.* NPC estimated that 15 percent of the drilling footage would be offshore by 1985. This figure was assumed for the entire projected period. Schedule III-C-6 sets out historical onshore versus offshore drilling. The 15 percent offshore drilling effort would represent a substantial increase over recent levels.

Line 2 - Lease Acquisition Cost

Lease acquisition costs have varied erratically over the years. To a large extent this level depends on Government policy. A summary of the Government's OCS leasing is shown on Schedule III-C-7.

Schedule III-C-8 shows the ratio of the total (both oil and gas) successful well costs to the 5-year moving average lease acquisition expenses. There has been a significant increase in this ratio; for example, in 1967 this ratio was .37; however, by 1974 it rose to .87. This upward trend is expected to continue. The factor used for the cost projection was 1.16, based on the following estimates:

1) The projected 1985-2000 average successful oil well cost represents a 45 percent increase over the present level. The estimated average (1985-2000) total successful well cost is $2,707** million x 1.45 = $3,925 million per year.

2) The average lease acquisition cost is projected to be $4,555 million per year, based on the following assumptions:

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*NPC, U.S. Energy Outlook, 1972.

**1974 data (Schedule III-C-8).

(a) Six lease sales will be offered each year by the Government.

(b) The average size lease sale will be 800,000 acres.

(c) The average price per acre will be $2,200 (1970-1975 average).

(d) The average leased/offered ratio will be .384 (1970-1975 average).

(e) Non-OCS leasing will be $500 million per year (1972-1974 level).*

3) The projected lease acquisition cost, $4,555 million per year, divided by the projected total successful well cost, $3,925 per year, is 1.16.

4) The projected lease acquisition cost component is the cost per foot drilled with a two-year lag multiplied by 1.16.

The lease acquisition cost is one of the most uncertain cost components in our price projection. It is difficult to predict future government leasing policies and prices which industry is willing to pay for offshore acreage. Therefore, the 1.16 multiplier has to be considered as a best judgement estimate.

Line 3 - Lease Equipment and Other Production Facilities

Little information is available regarding this cost component for oil. It is assumed that this cost would be similar to the corresponding cost for natural gas. In that part of Chapter III-D dealing with the cost of non-associated new gas, it was determined that lease equipment and other production facilities were approximately 23.2 percent of the cost of drilling successful wells. This ratio was applied here to estimate this cost component.

Line 5 - Dry Hole Cost

The dry hole cost allocated to oil costs is the projected cost per foot drilled with a one-year lag

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*Source: Chase Manhattan Bank, Capital Investments of the World Petroleum Industry, 1974.

divided by the productivity factor, and divided again by a factor, 1.12.

The 1.12 factor is necessary because oil wells are less deep and hence less costly than gas wells. The FPC adopted a constant factor of 1.08 to increase dry well costs attributable to gas. This factor has been updated to a level between 1.12 and 1.28. The low portion of the range was assumed for this study for both oil and gas.

Schedule III-C-9 sets out the dry hole costs per foot drilled which are allocated to oil costs. They are shown in current and in constant 1975 dollars. The dry hole costs were allocated between oil and gas according to the proportions of oil well costs to the total successful well costs. There is likely to be a significant increase in this cost component in 1975 dollars. The annual percentage increase since 1966 has been 5 percent for onshore drilling and 16 percent for offshore drilling. There have been three primary reasons for these increases.

First, the success ratio, as shown on Schedule III-C-10, has fallen over the years for both onshore and offshore drilling. The NPC* predicted that this ratio will continue to fall, but at a slower rate than it had in the past.

Secondly, onshore dry wells have been drilled deeper over the years. Schedule III-C-11 sets out the average dry well depth since 1961. The average cost onshore per well and per foot increases significantly the deeper the well as shown on Schedule III-C-12. No relationship is apparent in offshore drilling

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*NPC, U.S. Energy Outlook, 1972.

between depth and cost, primarily due to the lack of a reasonable sample in both the shallow and deep depth intervals.

Lastly, the cost of drilling per foot has increased at a much faster pace than the general level of inflation because of substantial increases in costs for materials and labor.

The projected cost of dry holes per foot drilled is based on a linear trend line of the historical data located in Columns 4 and 5 of Schedule III-C-9. It is therefore assumed that the historical trend will extend into the future. The projected costs are shown on Sheet 2 of Schedule III-C-9 as labeled. The costs are averaged between onshore and offshore based on weights determined by the National Petroleum Council.*

Line 6 - Geological, Geophysical, Land Department, Lease Rental, and Other Production Expenditures Including Direct Overhead Expenses

This cost component was estimated at 38 percent of the cost of successful wells. The 38 percent is the ratio of the G&G, etc. expenses (1969 to 1972) to the successful well costs (1971 to 1974). The two-year lag allows the time for development. (See Schedule III-C-13.)

Line 7 - Exploration Overhead

The exploration overhead expense is assumed to equal 6 percent of the cost of dry holes plus lease acquisition cost with a three-year lag.

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*NPC, U.S. Energy Outlook, 1972.

Schedule III-C-14 shows the ratio of exploration overhead expense to dry hole costs plus lease acquisition cost from 1967 to 1973. The average for the period was 9 percent; however, dry hole costs and lease acquisition costs are expected to rise sharply over the projected period, which will keep this ratio at a low, or falling level.

Line 9 - Production Operating Expense

Production operating expense was estimated to be $.47 per barrel based on a special survey of several crude oil producers. This expense is assumed constant over the forecast period.

Line 10 - Net Gas Credit

Associated/dissolved natural gas produced with crude oil provides added revenues above the sale of crude oil. A gas credit is required to account for this revenue.

In 1975, the ratio of associated/dissolved gas produced to crude oil production was 1.5 Mcf to each barrel of oil. This ratio has been on a downward trend, because a higher proportion of gas is produced in the earlier production years of the well. This trend is expected to continue. The NPC* predicted a ratio of .85 by 1985 which represents a declining rate of 6 percent per year. Beyond 1985, this ratio is expected to decline further, but at a slower pace, by 2.5 percent per year.

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*NPC, U.S. Energy Outlook, 1972.

Schedule III-C-15 sets out the calculation for the net gas credit.

Line 11 - Return on Working Capital

Little information is available regarding the amount of working capital needed for crude oil operations. The Federal Power Commission estimated this amount for gas operations. It is assumed in this study that crude oil operations have the same relative percentage of working capital to other expenses as in the natural gas industry.

Return on working capital is therefore taken as [(Line 8 x .125 x 1.21) + (Line 9 x .125 x 1.48) + (Line 2 x 1.5)] x 0.15. (See Chapter III-D.)

Line 12 - Total Cost of Oil

The cost components of Line 1 through Line 11 were used in a DCF calculation at an internal rate of return of 15 percent to determine the cost of new crude oil. The main purpose of the DCF calculations is to estimate the carrying charges on the invested capital. The DCF calculation sets the discounted net income flow to the discounted costs. In the oil and gas industries there are substantial pre-production costs, a portion of which can be immediately amortized according to current provisions of the Federal tax law. The remainder of the pre-production costs are written off during the production period.

The short DCF form was used in this calculation:

$\sum_{i=1}^{N}$ discount factor (mid-point of production year) x (price - cost) = discounted pre-production costs, where N equals the operating life of the well.

Assumptions used in the DCF calculation were:

1) G&G etc. expenses, exploration overhead, lease acquisition expenses, dry hole cost, successful well cost, and production facility expense were considered pre-production expenses.

2) The FPC's percent of the pre-production cost which determined the tax credit used in gas costing was applied.*

3) An income tax rate of 48 percent was applied.

4) A royalty rate of 16 percent was assumed.

5) State production tax was estimated at 6.8 percent (See Schedule III-C-17).

6) The discount factor used was the sum of the mid-year discount rates weighted according to an oil well depletion curve over 18 years. No build-up period was assumed and secondary recovery methods were assumed to be employed in the 9th year.

The calculation of the required crude oil price under the DCF method is located on Schedule III-C-16, Sheets 1 through 6.

Once this price is determined, the cost components on lines 12 (return), 13 (royalty), 14 (state production tax), and 15 (income tax) can be determined by netting out the other costs and applying the appropriate tax and royalty rates.

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*FPC Opinion No. 699-H.

c) Major Uncertainties of Cost Forecast

Set out below are the major uncertainties of this forecast:

1) The cost per foot drilled for successful well and/or dry wells may not continue its past trend.

2) Offshore drilling may not reach 15 percent of the total drilling effort by 1985.

3) When necessary, it was assumed natural gas costing methods were applicable to crude oil.

4) Lease acquisition expenditures have varied erratically, and are, therefore, difficult to forecast.

5) New technology may be introduced which may affect the cost of finding oil, the drilling cost, or the productivity factor.

6) The income tax rate was assumed at 48 percent.

7) The productivity factor was assumed to increase slightly and then remain constant. Any variation of this factor, up or down, would have a significant impact on the production cost. The productivity factor may be slightly dependent on price. A problem of circularity exists with this methodology to the degree to which this is true.

d) Cost of Delivered Alaskan Crude Oil Under Price Controls

Alaskan crude oil will be delivered to the Lower 48 States commencing in the late 1970's. The initial capacity of the Alaskan pipeline is 2 MMBD. By the 1990's this line is expected to be expanded to 4 MMBD to carry oil from the Naval Petroleum Reserve No. 4 and other undiscovered sources, as well as from the North Slope.

The price of Alaskan oil delivered to the Lower 48 States under price controls is projected to be delivered at the cost of foreign crude oil for 1985 and 1990, and the cost of new crude oil produced in the Lower 48 States for 1995 and 2000. The projected cost of delivered foreign crude oil is not far out of line with the cost of new domestic oil until 1995. It is therefore assumed that the authorities will allow Alaskan oil to be priced at foreign oil prices until 1995.

The basis for this assumption comes from FEA's schedule of price increases which deletes the Alaskan estimates, and from the Energy Policy and Conservation Act, which states that the weighted average --

> "(A) excludes up to 2 million barrels a day of crude oil production transported through the trans-Alaska pipeline from the computation of the maximum weighted average first sale price specified in subsection (a); and,
>
> "(B) establishes ceiling prices (or a manner determining prices) for the first sale of crude oil production referred to in subparagraph (A) such that the actual weighted average first sale price for such production will not exceed the highest actual weighted average first sale price permitted under the regulation for significant volumes of any other classification of domestic crude oil."

Set out in Table 7 is the projected landed cost of Alaskan oil under price controls:

TABLE 7

ALASKAN OIL (LANDED) (1975 DOLLARS)

1985 1985	-	$12.30/barrel
1990	-	$13.30/barrel
1995	-	$14.00/barrel
2000	-	$15.00/barrel

e) Projected Shale Oil Cost

Shale oil is one of our Nation's largest undeveloped natural resources. Approximately 418 billion barrels of shale oil are classified as producible, but some of this is not commercially available because of economic, legal or political reasons. Thus, the cost estimate herein applies only to an approximate 50 billion barrels which is considered high yield shale (greater than 30 gal./ton).

The great majority of the shale oil deposits are located in a single geological formation in Western Colorado, Utah, and Wyoming, known as the Green River Formation.

Oil has never been commercially produced from shale in the U.S. Shale oil cost estimates have always been above the cost of conventional oil, and constraints such as water availability and environmental considerations have further deterred production. This situation is expected to continue into the 1980's. The .3 MMBD projected production programmed for 1985 in this study may be optimistic. It assumes that essentially all the present projects planned as of 1975 are completed. Some of these are shown on Table 8 on the following page.

TABLE 8

Name	Plant Size (MBD)	State	Land Ownership Private (PR) or Public (PU)	Status
Colony Development Co.	50	CO.	PR	suspended indefinitely
Union Oil Co.	50	CO.	PU	early stages of planning
Superior Oil Co.	44	CO.	PR	testing and research
Gulf Oil Co. & Standard Oil Co. of Indiana	50	CO.	PU	pre-development studies under way
Shell Oil Co. & Ashland Inc.	50	CO.	PU	pre-development studies under way
White River Oil Corp.	50	CO. & UT.	PU	pre-development studies under way
Occidental Oil Co.	50	CO.	PR	advanced stage of research

By the year 2000, a major and optimistic assumption is made that current problems associated with shale oil production will be resolved, and that the cost of shale oil will come more in line with the cost of new conventional crude oil. Therefore, the production level is expected to rise substantially.

There has been a phenomenal increase in the engineering cost estimates for shale oil plants since 1970 when the construction cost of the Tosco II plant was estimated to be between $250-300 million. In 1975 the estimated cost of a shale oil plant was over one billion dollars. The increase is considerably in excess of the general rate of inflation.

The source of the 1975 shale oil cost used in this analysis was a study prepared by the Synfuels Interagency Task Force (SITF)*. The basic cost components used by SITF in their DCF calculation to determine a required price are presented in Schedule III-C-18. The basic assumptions made in the study were as follows:

- Required price is based on a DCF 15 percent internal rate of return.
- Interest during construction is 10 percent.
- Tax rate is 50 percent.
- Prices remain at January 1975 level.
- The calculation is based on a single 50 MBD plant.
- Lease bonus bids are not included.
- The life of the plant is 20 years.
- The plant is an underground mine with aboveground retort.
- The shale quality is 30 gallons per ton.
- Land costs are not included.

The result of the SITF calculation was $12.70 per barrel for syncrude produced from shale oil as of January 1975. It is assumed that the forecast cost for investment in a shale oil plant will continue to increase at a greater rate than the general inflation rate, by 3 percentage points per year.

As shown on Schedule III-C-18, 34.7 percent of the total operating cost for a shale oil plant is depreciation of plant investment. It is further assumed that other operating costs remain constant in real terms over the projected period. With these assumptions the projected cost of shale oil can be estimated for each year as shown on Schedule III-C-19.

Schedule III-C-20 averages the different costs of oil shale according to the plant vintage.

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*Recommendations for a Synthetic Fuels Commercialization Program. November 1975.

The projected average cost of producing syncrude (including upgrading) from shale oil, excluding lease bonus bids and land costs is shown on Table 9.

TABLE 9

	$/Barrel
1985	$13.88
1990	14.44
1995	15.02
2000	15.64

The above analysis assumes conventional shale oil operations (i.e., mining, crushing, aboveground retorting and upgrading) and no government subsidies.

The in situ process is an alternative method of extracting hydrocarbons from shale. This process is carried out underground, which may eliminate many of the environmental problems as well as the water supply constraint associated with aboveground retorting. This process is not sufficiently advanced to make cost estimates at this time.

It is assumed in this study that there will be no government subsidies for the shale oil industry. The above cost figures could be lowered if there were to be subsidies. Also, it is possible that the second generation plants will be less costly than the initial ones. The above cost figures would be still lower to the extent this occurs.

f) Cost of Tertiary Recovery of Crude Oil

It is estimated that only about 25 percent* of the original oil-in-place is recoverable by the use of primary techniques. In order to increase the

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*U.S. Department of Commerce, National Technical Information Service, PB-244-970.

output of a field it is customary to plan for some kind of enhanced recovery method which will come into use as primary production diminishes, thereby prolonging the life of the field. Today about 50 percent of U.S. production is from fields with some kind of enhanced recovery.

There is no clear dividing line between secondary and tertiary recovery methods, but "secondary" is generally taken to include such relatively inexpensive methods as water flooding and non-miscible gas injection. "Tertiary" recovery methods include the use of miscible water or gas injection, steam flooding, and in situ combustion -- methods which require considerable investment and a time lag of some years before recovery of the additional oil.

Secondary recovery methods are estimated to produce about 8-10 percent of the original oil-in-place, bringing about the total recoverable by primary and secondary techniques up to about 35 percent. Tertiary methods are still in the experimental stage but it is estimated that their use could increase the total recoverable oil to about 60 percent.

Tertiary recovery methods are expensive because elaborate field tests must be made to determine the extent of the reservoir and its geological characteristics such as oil concentration, porosity of sandstone, and permeability. Injection equipment may have to be custom made and a considerable quantity of chemicals may be required. If the field had been water flooded under secondary recovery, this water would usually have to be removed; therefore, it would seldom be an economic proposition to reopen old wells. Thus, it would be more economical to plan at the outset for the whole producing life of the field.

Because of the time required for preparation, it is not expected that there will be significant production by tertiary methods until at least 1985. The FEA* predicts that 1 MMBD might be possible in 1985 (6-7 percent of total domestic production) but this seems to be overly optimistic. It is assumed in this study that tertiary oil production will be: 0.6 MMBD - 1985; 1.0 MMBD - 1990; 1.6 MMBD - 1995; and, 2.3 MMBD - 2000.

In order to estimate cost of oil produced by tertiary recovery methods, a cost estimate for a hypothetical oil well producing under primary recovery and then producing by miscible augmented water flooding was analyzed. A discounted cash flow calculation was used with a 15 percent internal rate of return to estimate the cost of the average production over the life of the well. The average cost per barrel of oil produced under primary recovery and then a tertiary technique was calculated using similar methodology to that employed in estimating new crude oil costs.** Secondary production was deleted because of the problems water flooding causes for tertiary techniques. The investment for tertiary recovery is assumed to take place in the eighth and ninth years. Tertiary production would start in the eleventh year as primary production is depleted. Tertiary production is carried on until the twenty-first year.

The main investment for tertiary production was based on the lower range estimated by Department of Commerce*** -- $3 per barrel multiplied by the tertiary

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*FEA, <u>National Energy Outlook 1976</u>.

**See Projected Cost of New Conventional Crude Oil (Lower 48 States).

***See U.S. Department of Commerce, National Technical Information Service, PB-244-970.

production volume to determine the investment. Operating costs for tertiary production are taken as a constant $1.25 per barrel, which is also the lower end of the range estimated by the Department of Commerce.*

Annual costs for primary production are the operating expenses at $.47 per barrel and a figure for interest on working capital which was an average for the period, based on line 11 in Schedule III-C-1.

A calculation was made of costs in each of the 21 years, assuming tax credits in the pre-production years in the same way as in the calculation of "conventional" oil costs. The costs were then discounted at 15 percent to arrive at the discounted cash flow.

The calculation of the net cash flow assumed a royalty of 16 percent, state production tax at 6.8 percent and income tax at 48 percent. Revenues, net of tax and depreciation, tax credit per annum, operating expenses, and interest on working capital, were then discounted at 15 percent. The required price was the one at which the discounted cash flow equated its discounted costs.

Four 21-year periods were studied, and the results are presented in Table 10.

TABLE 10

PROJECTED TERTIARY OIL COST

	Start of Primary Production	Start of Tertiary Production	Required Price $/Bbl
1975-1995	1978	1985	15.75
1980-2000	1983	1990	17.50
1985-2005	1988	1995	19.00
1990-2010	1993	2000	20.00

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*See U.S. Department of Commerce, National Technical Information Service, PB-244-970.

The average cost of oil produced by this method is estimated to be the cost for each year weighted according to the projected production level. Set out below in Table 11 is the calculation of those averages.

TABLE 11

AVERAGE TERTIARY OIL COST

Year	Quantity Produced (MMBD)	Projected Cost ($/Barrel)	Percent Supplied by year	Average Cost $/Barrel
1985	.6	$15.75	1985-100.0%	$15.75
1990	1.0	17.50	1985-60.0% 1990-40.0%	16.45
1995	1.6	19.00	1985-37.5% 1990-25.0% 1995-37.5%	17.41
2000	2.3	20.00	1985-26.1% 1990-17.4% 1995-26.1% 2000-30.4%	18.19

In this analysis the cost of the incremental supply of tertiary produced oil is quite high. Two major reasons are -- the foregone secondary produced oil which substantialy raises the average per barrel cost, and the slow start-up time after a high initial investment.

The incremental cost of tertiary cost is set out on Table 12.

TABLE 12

INCREMENTAL COST OF TERTIARY OIL

	$/Barrel
1985	21.85
1990	24.24
1995	26.26
2000	26.99

Many uncertainties surround the cost projection for tertiary oil. In the first place, the technology of tertiary recovery methods is only partially developed. It is fair to assume that improved technology will reduce costs; however, little cost information is currently available. Secondly, there are a number of different types of tertiary recovery methods, some being more expensive than others in relation to their effectiveness. The characteristics of individual fields would determine the most suitable method to use. Further, a 15 percent rate of return may be considered insufficient for initial commercial operations. And, insofar as there may be existing shutdown wells which have not been water flooded, the cost of recovery oil by tertiary methods could be below the cost estimated in this report.

4. Projected Price of U.S. Crude Oil Under Free Market Conditions

While the free market projection for domestic crude oil is less complex than the price control case, it is attended by equal if not greater uncertainty. This is because domestic crude oil prices are assumed to equate to the projected foreign crude oil price delivered to the U.S. refineries after adjustment for quality differences.

The projected foreign price for the marker crude, Saudi Arabian light, delivered to the U.S. coastal refineries was developed in Chapter III-B of this report. The "base case" was used in this section.

In 1975 the average price of all foreign crude oil delivered to the U.S. was approximately 30 cents per barrel higher than the marker crude. This differential will be used as the cost above the marker crude for foreign crude oil over the projected period.

Set out on Table 13 is the projected landed price of foreign crude oil for the "base case."

TABLE 13

FOREIGN OIL PRICE PROJECTION (LANDED)
($/Barrel)

	Marker Crude				
Year	FOB Saudi Arabia	Freight	Landed	Plus Differential	Landed: All Foreign Crude
1975(actual)	10.46	1.68	12.14	.30	12.34
1976	11.10	1.75	12.85	.30	13.15
1985	10.00	1.75	11.75	.30	12.05
1990	11.00	1.75	12.75	.30	13.05
1995	13.00	1.75	14.75	.30	15.05
2000	16.75	1.75	18.50	.30	18.80

The quality premium of U.S. crude oil, which is lower in sulfur than most world oils, is assumed at 50 cents per barrel for Lower 48 States crude and 25 cents per barrel for Alaskan crude oil. (Most of the Lower 48 States crude contains less than .5 percent sulfur while Alaskan crude contains about 1 percent sulfur, compared to the Arabian light marker crude at 1.8 percent to 2.4 percent sulfur.) The weighted average quality premiums assigned to domestic crude oil are: 1985-46 cents per barrel; 1990-45 cents per barrel; 1995-43 cents per barrel; and 2000-43 cents per barrel, according to the projected production levels presented in Section 2 of this Chapter.

Adding these quality premiums to the delivered foreign crude oil prices (supra) yields a national projected average price for all source of domestic crude oil delivered at coastal refineries, as shown on Table 14.

TABLE 14

PROJECTED NATIONAL AVERAGE PRICE OF CRUDE OIL
($/Barrel)

1985	-	$12.51
1990	-	$13.50
1995	-	$15.48
2000	-	$19.23

There are considerable uncertainties associated with this forecast. Some of the major ones are set out below.

a) All the uncertainties attending the world oil price forecast in Chapter III-B are applicable here.

b) U.S. refiners may give domestic crude oil supplies an additional premium above foreign oil because of security of supply.

c) The average quality and transportation differential of $.30 per barrel of all foreign crude delivered to the U.S. above the marker crude may change over time; e.g., OPEC is presently determining the differential between crude types as a marketing mechanism.

d) The assumed quality premium for domestic crude oil over foreign oils may be different in the future. A larger percent of U.S. refineries will have the ability of running sour crude as revamping of old refineries takes place and as new refinery construction is completed.

e) The foreign oil price forecast is below the projected cost of shale oil until 1990 and the projected cost of new conventional and tertiary oil until 1995. The U.S. Government may choose again to support domestic production by tariffs, quotas, or other means which have similar results. If this action were to be taken it could mean about a $2 per barrel increase in the average cost of crude oil delivered to U.S. refineries.

5. Price of Crude Oil to Refinery, Refinery Margin, and Price of Petroleum Delivered to Consumers

a) Delivered Crude Oil Price in 1975

Five key refining centers (KRC) were chosen to represent supply points of petroleum products for the selected areas across the Nation. The KRC's are Great Lakes, East Coast, Oklahoma-Kansas, Gulf Coast, and the West Coast. The map on Schedule III-C-21 sets out the general area of each of the KRC's and the locations of the large refineries in each area. Approximately 83 percent of the U.S. total refining capacity as of January 1, 1975 was located in these KRC's. (See Schedule III-C-22).

Seventeen cities were chosen as retail pricing points. At least one city was chosen in each of the census regions. The location of these cities and a map of the census regions are set out on Schedule III-C-23 of this report.

The current price control system when first employed by the Government, i.e., old and new price ceilings, created substantially different crude costs between refiners. The entitlement program was established to eliminate most of these differences. The Government determines the average proportion of old (cheaper) crude oil being used by all the U.S. refineries. If a refinery has a higher percentage of old oil than the average, then it pays entitlements to refiners with a lower percentage of the old oil. The entitlement program tends to equate all U.S. refiners' crude oil prices except in the following cases -- domestic new crude oil prices do not equal delivered foreign prices; different refiners have different foreign crude oil sources with different prices; and transportation and quality cost differentials.

The average 1975 crude oil cost delivered to refiners in each of the five KRC's was estimated under the following assumptions:

1) Foreign crude oil sources for each KRC were the same as sources for the PAD in which the KRC is located. Schedule III-C-24 sets out imports of foreign crude oil by PAD and country of origin.

2) The domestic field price of new crude oil was assumed to be $12.08 per barrel and domestic field price of old oil was assumed to be $5.25 per barrel, the national average 1975 prices as published by FEA in the Monthly Energy Review.

3) In 1975 old crude oil supply was 41 percent of refinery runs. All KRC's were assumed to have this percentage because of the entitlement program. The remaining 59 percent was allocated to new domestic crude oil and foreign oil based on the refining district breakdown of supply as reported by the Bureau of Mines.

4) Estimated transportation costs to the KRC for domestic crude oil were based on the Bureau of Mines refinery district sources of supply and ICC pipeline rates. Estimated transportation costs to the KRC for foreign crude oil were developed from the AFRA world scale tanker rates for Large-1 size tanker and ICC pipeline rates, where relevant.

Based on this analysis, the 1975 delivered crude oil price to each KRC was determined by the weighted average of the three sources of supply. Schedule III-C-25 sets out these averages, summarized as follows:

TABLE 15

Great Lakes	-	$9.62/barrel
East Coast	-	$9.42/barrel
Oklahoma-Kansas	-	$9.52/barrel
Gulf Coast	-	$9.48/barrel
West Coast	-	$9.98/barrel

b) Projected Crude Oil Supply for KRC's

Each of the KRC's will continue to be supplied by different sources of crude oil which may have different prices relating to transportation cost and/or quality differences. These price differences will continue in various degrees into the future. The forecast supply sources of crude oil and shale oil were developed for each of the KRC's by minimizing transportation cost, thereby maximizing the field or plant value. Schedule III-C-26 sets out the estimated refinery runs by sources of supply for five-year intervals, 1975-2000.

The following analytical assumptions were made for these estimates of supply sources:

1) U.S. refining crude runs will remain at about 80 percent of U.S. petroleum demand; i.e., the KRC refinery runs are assumed to increase by the same rate as the EEI Demand Case B to the year 2000.* Thus, refinery runs will be: 1985-17.9 MMBD; 1990-19.2 MMBD; 1995-20.5 MMBD; 2000-21.9 MMBD.

2) Foreign crude oil will represent the following proportion of U.S. refinery crude runs: 1975-32 percent; 1985-39 percent; 1990-32 percent; 1995-34 percent; 2000-36 percent.

3) Alaskan crude oil will be used first on the West Coast, replacing all foreign crude oil. After the Alaskan pipeline is expanded above the 2 MMBD capacity, excess supply will be transported to the Great Lakes KRC and the Gulf Coast KRC.

4) Shale oil supplies will be divided between the Oklahoma-Kansas KRC and the Gulf Coast KRC.

5) The flow of domestic crude oil to the East Coast from the Gulf Coast is replaced by foreign oil.

c) Projected Crude Oil Price Delivered to the KRC

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*EEI, Economic Growth in the Future, June 1975.

The future delivered crude oil prices have been estimated under a price controlled case and a free market case.

1) Price Control Case.

If price controls exist, we would expect controls to set domestic crude oil prices below world prices. Then, a competitive advantage would exist for U.S. refiners with a higher proportion of the domestic oil. An entitlement program (or its equivalent) would then likely be instituted to equate in terms of costs the proportion of inexpensive crude oil supplied to all refiners.

In administering this program, it is assumed that the government will first calculate the weighted average price of all domestic crude oil feedstock. This calculation is shown on Schedule III-C-27. For simplicity, the pricing points are assumed to be the wellhead for conventional and tertiary Lower 48 oil, the syncrude plant for shale oil, and the West Coast for Alaskan oil. It is assumed that foreign oil prices will set a ceiling for both Alaskan oil and shale oil until the cost of shale oil and the price of Alaskan oil are below projected world oil prices. This occurs in 1990 for shale oil and 1995 for Alaskan oil. The weights used for the calculation are the projected production levels covered in Section 2. The weighted average domestic feedstock costs in 1975 dollars are thus projected as follows:

TABLE 16

($/Barrel)

1985	10.47
1990	12.20
1995	13.37
2000	14.58

The next step in this entitlement program under the price control case is to determine the U.S. average proportion of domestic oil vs. foreign oil refinery runs. All refiners who have a higher proportion of less expensive domestic crude oil than the U.S. average will have to pay entitlements to refiners with a lower proportion. The end result of this program in terms of cost is to keep the proportion of foreign crude oil the same for all U.S. refiners, e.g., 39 percent foreign and 61 percent domestic crude oil for the year 1985. Therefore, the refiner feedstock cost for all the KRC's will differ only with respect to transportation and quality cost differentials. The calculation of the delivered crude oil cost to the KRC under the price control case is presented on Schedule III-C-28. The foreign crude oil price forecast used on this schedule was the "base case" as developed in Chapter III-B. All foreign crude oil sources are assumed to rise or fall on an absolute dollar basis according to the marker crude (Saudi Arabian light), thereby keeping the freight and quality differentials constant.

The geographic source and type of foreign crude oil to be delivered to each of the KRC's to 2000 is not possible to predict. In 1975 the average price of all foreign crude oil delivered to the U.S. was approximately 30 cents per barrel higher than the marker crude. Therefore, this differential will be used as the cost above the marker crude for the projected period for all KRC's.

Schedule III-C-28 also shows the weighted average domestic crude oil price. The transportation cost represents weighted average transportation for the different sources of supplies in each KRC. Transportation costs are assumed to remain constant in 1975 dollars throughout the projected period.

The projected foreign crude oil prices and the projected average domestic prices are averaged according to the national proportion of foreign and domestic supplies.

The results of the projections are on Table 17 below:

TABLE 17

PROJECTED REFINERY COST OF CRUDE OIL
($/Barrel)

KRC	1975 (Actual)	1985	1990	1995	2000
Great Lakes	9.62	11.41	12.79	14.05	16.42
East Coast	9.42	11.45	12.88	14.38	16.48
Okla.-Kansas	9.52	11.32	12.71	14.18	16.34
Gulf Coast	9.48	11.17	12.57	14.04	16.20
West Coast	9.98	11.14	12.53	13.99	16.15

2) Free Market Case

In the free market case it is assumed that domestic crude oil will equate at the refinery to the projected foreign crude oil price after adjusting for transportation costs and quality differentials. (See Section 4.) The proportions of foreign vs. domestic oil needed to calculate the weighted average crude oil price are the proportions that were developed above under Section 2.

The projected price for crude oil delivered to the KRC under free market conditions in 1975 dollars is set out on Schedule III-C-29, summarized as follows:

TABLE 18

PROJECTED REFINERY COST OF CRUDE OIL
$/Barrel

KRC	1975 (Actual)	1985	1990	1995	2000
Great Lakes	9.62	12.74	13.76	15.75	19.50
East Coast	9.42	12.05	13.05	15.05	19.30
Okla.-Kansas	9.52	12.81	13.71	15.80	19.45
Gulf Coast	9.48	12.39	13.43	15.43	19.16
West Coast	9.98	12.30	13.41	15.40	19.14

d) Projected Refinery Margin

It is necessary to forecast the refinery margin as the approximate cost of refining crude oil into petroleum products.

In 1975 the gross refinery margin varied between 6.5 and 9.5 cents per gallon. This estimate was determined by the following steps:

1) Calculate the delivered feedstock cost for each KRC (Schedule III-C-25).

2) Determine the refinery price for each petroleum product. Regular gasoline, distillate fuel oil, residual fuel oil, and the "remainder of the barrel" were the products used in this study.

3) Calculate the differences between the refinery feedstock cost and the refinery product price.

4) Calculate a weighted average refinery margin (gross margin) by using the refinery product yields as weights. (See Schedule III-C-31.)

The refinery margins for each KRC in 1975 are set out on Schedule III-C-30. The product prices are published prices in trade journals and/or prices obtained from industry sources. The price for the "remainder of the barrel" is the weighted average price of LPG, jet fuel, naphtha, lubes, and kerosene, available only for the Gulf Coast KRC. Some of the published product prices used here are spot prices. Refinery margins based on spot product prices are not ideal because of the possibility of short-term variations resulting from supply and demand factors.

The projected refinery petroleum product prices equal the projected crude oil costs plus the projected refinery margin. Based on a historical analysis, it was assumed that the refinery margin would not increase in real terms over the current level except for fuel costs, a conservative assumption. This analysis is set forth on Schedule III-C-32. The refinery operating costs were divided into four components -- fuel, labor, investment and maintenance, etc., and chemicals. Since the early 1960's the fuel cost component increased substantially greater than the rate of inflation. In the composite, the other three components remained fairly stable.

In 1974 the fuel consumed by U.S. refineries was equivalent to 9 to 10 percent of crude oil runs. In this study it is assumed that 9 percent of equivalent crude runs will be used as fuel over the projected period. Therefore, the gross refinery margin will increase by 9 percent of the increase in crude oil cost.

While it is assumed that the refinery margin for individual petroleum products will remain constant except for fuel cost increases, an adjustment in the margin for residual fuel oil is required, as follows:

1) The Oklahoma-Kansas low sulfur residual fuel oil margin will increase to the prevailing Gulf Coast level to reflect its future higher value.

2) The price for regular (high) sulfur residual fuel oil for all KRC's will equate to the delivered crude oil cost on a price per Btu basis. Residual fuel oil contains approximately 8 percent more Btu per barrel than crude oil; therefore, it is projected at 8 percent higher on a price per barrel basis than crude oil costs.

Thus determined, Schedules III-C-33 and III-C-34 set out the projected refinery price for each petroleum product in each KRC under the price control case and the free market case.

e) Forecast of Consumer Prices

The final step in this analysis is to estimate the price of petroleum delivered to consumers. Retail petroleum prices are the equivalent of the refinery price plus transportation costs and dealer margins.

Seventeen cities were chosen as general pricing points. At least one city was located in each of the census regions. Schedule III-C-23 sets out the general location of each of the seventeen cities. The following refining centers are considered as domestic supply points for the numbered cities.

City Number	KRC
1.	Gulf Coast
2.	East Coast
3.	East Coast
4.	East Coast - residual fuel oil Gulf Cost - gasoline and distillate fuel oil
5.	Gulf Coast
6.	Gulf Coast
7.	Gulf Coast
8.	Great Lakes
9.	Great Lakes
10.	Great Lakes
11.	Great Lakes
12.	Oklahoma-Kansas
13.	Gulf Coast
14.	Oklahoma-Kansas
15.	West Coast
16.	West Coast
17.	West Coast

It is estimated that approximately 12 percent of domestic demand will be supplied by imported petroleum products over the forecast period. These imports are assumed to be priced at the same level as domestic petroleum products. This may be a reasonable assumption for the free market case; however, it may understate the average price of all sources of petroleum products for the price control case.

Petroleum product prices for five consuming sectors were evaluated in this study.

1) <u>Residential Heating</u> - Distillate tank wagon deliveries of 200-400 gallons.

2) <u>Small Commercial Heating</u> - Distillate tank wagon deliveries of greater than 400 gallons.

3) Industrial - Distillate and residual fuel oil truck transport deliveries.

4) Electric Generation - Large transport volume of residual fuel oil.

5) Automobile Transportation - Regular grade gasoline pump prices excluding federal and state excise taxes.

Schedule III-C-35 sets out the petroleum product prices for 1975 for each of the consuming sectors in each of the 17 cities. Sheet 1 shows the residential, commercial, industrial and transportation prices. Also estimated are the cost components which are -- refinery price, transportation cost to the city, truck transportation cost, and the dealer margin. The mode of transportation to the city was pipeline, truck, rail or water, whichever was the least expensive and accessible. The truck transportation cost and pipeline rates were based on tariffs filed with the ICC. The tanker and barge rates were obtained through industry sources. And, the dealer margins for distillate home heating oil and gasoline pump prices were the margins reported by FEA for 1975.*

The gasoline pump prices exclude federal and state excise taxes. These taxes range from 9 to 14 cents per gallon as of 1975.

The average 1975 fuel oil prices for steam electric generating plants are presented on Schedule III-C-35, Sheet 2 of 2, by census region. These data were obtained from publications of the Federal Power Commission which summarize Form 423 data filed by the power plants with the Commission. The schedule

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*FEA, Monthly Energy Review.

shows the price in cents per gallon, cents per MMBtu, and the sulfur content of the fuel oil. The fuel oil is an admixture of residual fuel oil, distillate fuel oil, and crude oil burned by the power plants, with over 90 percent residual fuel oil.

Petroleum transportation cost was assumed to remain constant for the projected period in 1975 dollars. This assumption appeared reasonable, although it was not analyzed in depth. The dealer margin was also assumed to remain constant in 1975 dollars based on historical data. Schedule III-C-36 sets out the cost components of the dealer margin for 1965 and 1975 in actual dollars and in 1975 dollars. In 1975 dollars the aggregate of the cost components remained remarkably stable, changing from 5.97 cents per gallon in 1965 to 5.82 cents per gallon in 1975.

As stated above, the sum of the transportation costs, dealer margin and the refinery product prices are assumed to equal the consumer product prices over the forecast period. These projected prices for cities within the different census regions are set forth for the residential, commercial, industrial, and transportation sectors on Schedules III-C-37 and III-C-38 for the price control case and the free market case, respectively.

The projected prices of residual fuel oil (RFO) for the electric utility market were determined on a census region basis. Four prices for each region were projected:

- High transportation cost - low sulfur
- High transportation cost - high sulfur
- Low transportation cost - low sulfur
- Low transportation cost - high sulfur

The high transportation cost represents prices of RFO delivered to approximately the center of the census region. The low transportation cost represents RFO prices for electric utilities located in metropolitan areas with refineries. The low sulfur prices are for RFO containing .3 percent sulfur to 1.0 percent sulfur depending on the local environmental restriction. Lastly, the prices for high sulfur residual fuel oil are for RFO containing greater than 1 percent sulfur.

It is estimated that the more typical case will be the low transportation and low sulfur case. Most residual fuel oil is consumed by generating plants located within a relatively short distance of a refinery, or on a navigable waterway because of the high transportation cost. On the other hand, electric utilities are generally located in large metropolitan areas, and these more populated areas typically have stricter environmental controls.

Schedule III-C-39 sets out projected prices for residual fuel oil as defined to electric utilities, for both the price control and free market cases, by census region.

f) Uncertainties Attending the Projected Refinery Prices and Consumer Prices

In broad terms, the greatest uncertainty attending the projected refinery prices and consumer prices are created by the uncertainty attending the projected crude oil prices. However, there remain considerable uncertainties in projecting refinery margins, transportation and distribution costs to the consumer, including --

1) The scheduled sulfur emission levels may change in the future. If they are tightened, then the projected residual fuel oil prices would likely be higher. If they were loosened, then the converse will probably be true.

2) The cost to refiners of desulfurizing residual fuel oil may change from the current level assumed in this study for the projections.

3) The gross refinery margin (except for fuel costs and some adjustments for residual fuel oil), transportation costs, and dealer margins were all held constant in 1975 dollars for the projected period. These costs may be higher or lower in 1975 dollars to the year 2000.

4) In some instances where volumes are large and distances relatively short, residual fuel oil pipelines could be used and this might reduce projected transportation costs.

5) Refiners under free market conditions have considerable latitude in adjusting their product margins for the individual products. No such market adjustments were considered in this study.

6) The current gross refinery margin used in the projection was based on current refinery yields. If refinery yields change because of Government action or demand factors, then the margins for the individual products could change in the future.

7) Large tank wagon prices for delivery of distillate to small commercial heating were projected at .5 cents per gallon below residential prices. If there is a tight market for

distillate fuel oil, this margin would disappear. However, if there is a soft market, this margin may broaden.

8) This study assumed import of petroleum products at domestic product prices. Under the price control case, this may be an understatement.

9) The type of Government control program used to equate refinery feedstock costs, necessary under the price control case, may differ considerably from the program assumed in this study. This would probably yield different prices.

10) The price of natural gas liquids (NGL) was not analyzed in this study. NGL is valued slightly lower than crude oil at this time. To the degree that this remains true, the price forecast for petroleum products, especially gasoline, may be overstated.

6. Range of Uncertainty in Projected Petroleum Prices

The most substantial uncertainty in projecting petroleum prices lies in future crude oil prices relative to other costs making up the consumer petroleum prices (supra). Throughout Chapter III-C uncertainties were listed regarding the price projections. However, the only price range developed was for the two general cases -- price controls and free market. This range was only about 11 percent for 1985 and 18 percent for 2000. This range does not incorporate the degree of confidence attending the price forecast.*

Set out in the following table is a range of prices which more accurately reflects the degree of uncertainty associated

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*For example, the base case forecast of world oil prices was used in Chapter III-C. Yet the high and low cases for world oil prices (supra, Chapter III-B) present a substantial range of uncertainty.

with the price forecast. These prices are domestic field prices or landed foreign prices.

TABLE 19

RANGE OF PROJECTED PRICES
($/Barrel)

	1985	1990	1995	2000
Low Range	9.60	9.60	9.60	9.60
Base Case[1]	11.86	13.65	14.78	17.77
High Range	16.75	18.75	20.75	23.75

[1] Average of price control case and free market case.

The lower level of the range is merely the 1975 U.S. weighted average cost of crude (domestic and foreign). It is probable that the U.S. refinery feedstock cost will not fall below the 1975 level. All indications point to higher prices in real dollars in the future. Some of these are:

a) Depletion of resource base.

b) Higher exploration and development cost.

c) No real substitutes for petroleum.

d) Government policy (i.e., Energy Policy and Conservation Act).

e) A larger percentage of expensive foreign oil to meet domestic requirements.

f) A larger percentage of expensive supplemental oil to meet domestic requirements (i.e., shale oil and tertiary oil).

The upper level of the range is the high foreign oil price projections developed in Chapter III-B. This price is believed to be sufficiently high in real terms to incorporate most of the upper pressures on future prices listed above.

If the average of the price control case and the free market case is used as a basing point, then a percentage variation from that price can be calculated. In general terms, this percentage variation can be carried through to the consumer price. The following table sets out the percentage variables from the basing point price:

TABLE 20

UNCERTAINTY OF U.S. PETROLEUM PRICE FORECASTS

	1985	1990	1995	2000
Low Range	-19%	-30%	-36%	-46%
High Range	+41%	+37%	+40%	+34%

Two observations can be made about this range. First, the percentage variation is asymmetrical, i.e., skewed to the upper side until the year 2000. And secondly, the percentage variation increases as time progresses.

D. GAS

1. Introduction

The price of gas is projected under two general cases, continuing price regulation and free market conditions. In the price regulation case, it is assumed that the Government would set the average price of natural gas below the replacement cost of new gas. In the free market case, gas prices are expected to increase toward parity with oil prices.

Gas prices are projected to increase more rapidly than the other fuels, primarily for four reasons. First, regulation has, for years, kept the price of gas substantially below its market value and below its replacement cost. Second, higher priced supplemental gas is expected to become a larger proportion of the total gas supply. Third, if price controls are eliminated, then the price of gas is expected to increase to parity with oil prices. Even if controls persist, the price of gas is projected to increase toward market value. Fourth, gas as a commodity is expected to increase in value due to limited supplies and its premium attribute is relative to other fuels.

The sections that follow first deal with the future supply and demand for natural gas, then turn to current and projected prices. The projected price sections first set out the projected U.S. average price of gas at the points of production or importation, then at the burner tip. Finally, a summary of the major uncertainties of this forecast is covered.

2. Supply and Demand for Gas

Future supplies of gas will come from several sources: Lower 48 production, synthetic natural gas, liquefied natural gas and Canadian imports.

The current domestic resource base is summarized as follows in trillions of cubic feet.

TABLE 1

MEASURED AND POTENTIAL U.S. NATURAL GAS RESOURCES (TCF)[1/]

	Measured	Inferred	Undiscovered
Alaska - Onshore	32	15	32
- Offshore	nil	nil	44
Lower 48 - Onshore	169	119	345
- Offshore	36	67	63
TOTAL U.S.	237	201	484

1/ Source: U.S. Geological Survey, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States, 1975.

These estimates are somewhat lower than previous Potential Gas Supply Committee (PGS) estimates. In part, this is because tight sand potential was not included in the U.S. Geological Survey (USGS) estimate, and also PGS estimated offshore potential out to a depth of 1,500 feet of water (457 meters) whereas USGS excluded potential reserves beyond 200 meters.

The USGS reserves are shown by areas in the Lower 48, as follows (in trillions of cubic feet):

TABLE 2

MEASURED AND POTENTIAL U.S. NATURAL GAS RESOURCES BY AREA (TCF)

	Measured	Inferred	Undiscovered
Pacific Coast - Onshore	5	4	13
- Offshore	nil	nil	3
Permian Basin	25	23	70
Gulf of Mexico - Onshore	82	59	133
- Offshore	35	67	50
Mid-Continent	34	21	72
Atlantic Coast - Offshore	-	-	10
Other (Appalachian & Other)	43	5	13

The same comments which were made regarding U.S. crude oil reserves are relevant here as well. USGS reserve estimates are developed from historical patterns. These patterns may not extend into the future, thereby changing the resource base.

Moreover, these reserves estimates are based on the pre-1974 price-cost relationship which has changed substantially. Today's higher prices will most likely increase the potential resource base, all other factors remaining unchanged. On the other hand, if field price regulation persists, keeping prices below market closing levels, then U.S. natural gas reserves may not reach their potential.

The assumed level of gas supply used in this study is set out in Table 3.

TABLE 3

PROJECTED SUPPLY OF NATURAL GAS
(Q Btu)

	1975 (Actual)	1985	1990	1995	2000
Lower 48 State Production					
Low	20.4 1/	17.0	16.0	15.0	13.7
High	20.4 1/	20.0	19.3	18.6	17.9
Canadian Imports	1.0	0.9	0.9	0.9	0.9
SNG	NA	0.8	1.2	1.7	2.2
Alaskan Gas	--	1.2	1.2	3.0	3.0
LNG					
Base Case	2/	0.6	1.0	1.5	2.0
High Case	2/	1.0	1.7	2.5	3.0
Total Supply					
Low Production and Base Case LNG 3/	21.4	20.5	20.3	22.1	21.8
High Production and High LNG 4/	21.4	23.9	24.3	26.7	27.0

1/ Net marketed production.

2/ Less than .5 Tcf.

3/ Assumed for continued price regulation.

4/ Assumed for free market case.

Most gas supply forecasts for the Lower 48 States point to a continuing decline of production from present levels. Schedule III-D-1 sets out six recent forecasts of Lower 48 States production as of 1985. Various assumptions and "scenarios" make up these forecasts; therefore, they are not entirely comparable.

In this study two levels of future Lower 48 States production has been estimated based on two sets of assumptions. In both cases the levels of reserve additions were first estimated and then production was assumed to reach that level by the year 2000.

The following are the primary assumptions in the low production case: a) there is a continuation of price controls, b) the price of new gas is set at the cost of new gas as developed in this report for the 300 Mcf per foot productivity level, c) the drilling success ratio remains constant, and d) there is an increase in drilling activity corresponding to the price increase.

Following are the primary assumptions in the high production case: a) there is an immediate decontrol of new gas prices, b) the price of new gas rises to the price of new domestic crude oil, c) drilling activity increases considerably as a result of higher prices, d) the productivity factor remains at 300 Mcf per foot (an optimistic assumption) and, e) the drilling success ratio remains constant.

In the costing section of this chapter, a productivity factor of 400 Mcf per foot was used. If this productivity factor were assumed in the supply forecast, then the projections of the Lower 48 States production could be as much as 33 percent higher.

The future proportion of Lower 48 States gas production, classified as "old" and "new" under the price control case, was estimated on the assumption that the rate of production from existing and new reserves was pro-rated between the two according to the proportion of each to the total "proved" reserves. This assumption may slightly overstate the proportion of "old" gas production.

The results of the calculation show the following breakdown between "old" and "new" gas.

TABLE 4

PROPORTION OF OLD AND NEW GAS

Year	Old	New	Total
1985	39%	61%	100%
1990	24	76	100
1995	12	88	100
2000	7	93	100

Canadian imports are expected to fall off slightly from the present level and remain constant over the projected period. Perhaps this is an optimistic assumption since existing Canadian export licenses will expire over this period.

It is assumed SNG production will be limited to coal gas. All planned plants are projected to be built by 1985. The increase in production to the year 2000 assumes emergence of the second generation process which will supplement the Lurgi process.

It is assumed Alaskan gas supplies (North Slope) will be on line by the early 1980's. By 1985 between .8 Q Btu and 1.2 Q Btu is projected, and it is assumed these deliveries to the Mainland will be about double by the year 1995.

LNG imports have the potential of being substantial in the years to come. However, the LNG import level may be restricted because of expected environmental siting problems and possible restrictions set by the Government.

The demand forecasts made by EEI are set out in Table 5. In most cases, there is a gap between supply and demand. This deficiency will result in an absolute short-fall in gas supplies which -- (1) must be fulfilled by alternative fuels or by supplies of natural gas from unknown sources, or (2) demand will be foregone.

TABLE 5

EEI DEMAND FORECASTS FOR NATURAL GAS
(Q Btu)

	1985	2000
Case A	32.5	40.6
Case B	30.0	33.4
Case C	28.3	21.6

3. Projected Average Price of Gas

The 1975 average price of natural gas in the U.S., measured in the field and at points of importation, was 48 cents per MMBtu. In future years, supplemental supplies -- Alaskan gas, LNG and SNG -- will make up an increasing proportion of the total supply. The estimated prices for each of these supplies are developed in the following sections of this chapter. The supply forecasts are then used as weights to average the different forecast prices into a national average price of gas.

Set out below are projected U.S. average prices of all gas measured in the field or, in the case of supplemental gas, at the city gate. The average prices are calculated on Schedule III-D-2, Sheets 1 and 2.

TABLE 6

PROJECTED GAS PRICE
(¢/MMBtu in 1975 Dollars)

	1985	1990	1995	2000
Price Regulation Case	149	183	229	270
Free Market Case	222	243	278	343

4. Wellhead Price and Cost of Natural Gas Under Regulation

It is assumed that the average field price of natural gas under continuing FPC price controls will be set below the cost of new gas. Two price levels set by the FPC are assumed, one for "new" gas dedicated to the market after 1973 and one for "old" gas dedicated to the market prior to 1973. The projected average price of gas will depend upon the relative price levels of "new" and "old" gas as well as the rate of depletion of both "old" and "new" gas.

Current gas costing methods were applied to calculate the projected cost for new non-associated gas. The projected cost is assumed to be the regulated level for "new" gas. This costing method utilizes separate components such as drilling costs, lease acquisition costs, operating costs, and carrying charges. Based on a discounted cash flow (DCF) calculation, the required price is determined at an internal rate of return of 15 percent. The results of this calculation are shown on Table 7.

All gas dedicated to the interstate market prior to 1973 is classified as "old" gas. In Opinion No. 749 (Docket R-478), the FPC set the nationwide rate for old gas at 29.5 cents per Mcf, effective July 1, 1976. It is assumed this price will not increase in constant dollars over the projected period except for gas under expiring contracts. No analysis was undertaken to estimate the amount of gas under expiring contracts. Therefore, the projected weights as between new gas and old gas are conservative.

TABLE 7

PROJECTED PRICE OF LOWER 48 STATES PRODUCTION UNDER CONTINUING PRICE REGULATION IN 1975 DOLLARS
(¢/Mcf)

	1985	1990	1995	2000
A. New Gas				
1. Price				
a. High Productivity	156	170	180	190
b. Low Productivity	209	229	242	255
2. New Gas Weight	61%	76%	88%	93%
B. Old Gas				
1. Price	29.5	29.5	29.5	29.5
2. Old Gas Weight	39%	24%	12%	7%
C. Weighted Average Price				
1. High Productivity	107	136	162	179
2. Low Productivity	139	181	216	239

The uncertainty in projecting the cost of new gas is substantial because of the number of variables and assumptions utilized. The most sensitive variable in this forecast is the productivity factor (reserve additions of non-associated gas per foot of successful wells drilled). To account for this uncertainty, two productivity factors were employed to calculate the future cost of new gas -- a high productivity factor and a low productivity factor.

Schedule III-D-3 and Schedule III-D-4 set out the projected cost components under the two productivity assumptions for new non-associated gas. Each cost component was projected and then divided by the estimated productivity factor to put it on a cents per Mcf basis. Each cost component will be described separately by line number:

Line 1 -- Successful Gas Well Costs*

The cost of successful gas well drilling is the projected cost per foot drilled for successful gas wells with a one-year lag prior to production, divided by the projected productivity level (Mcf per foot).

The productivity is the most sensitive variable in the forecast; therefore, two productivity cases were calculated. Schedule III-D-5 sets out the non-associated gas reserve additions per gas well foot drilled since 1947. There has been no definite trend in productivity from 1947 to the late 1960's. However, for the shorter period since 1967, there has been a serious decline, averaging 11 percent per year.

The FPC in its 1973-1974 biennial review** of new gas prices adopted a productivity factor of 485 Mcf per foot. This level is substantially above the level which

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*A successful well is a well completed for the production of oil or gas. In this section we are concerned with successful gas wells only, unless total successful wells are specified.

**Opinion No. 699-H, December 4, 1974.

existed over the past four years. In the 1976 review of the nationwide new gas cost, the FPC Bureau of Natural Gas based its cost estimates on two productivity levels, 454 Mcf per foot (12-year average) and 375 Mcf per foot (9-year average); and, the FPC Office of Economics recommended a productivity factor of 333 Mcf per foot (1970-1974 average*).**

As indicated above, two constant productivity factors are assumed in this forecast. The high productivity factor is 400 Mcf per foot drilled and the low productivity factor is 300 Mcf per foot drilled.

In using the high productivity factor, it is assumed that the expected rise in the proportion of offshore drilling will offset the recent decline in productivity. The use of the lower productivity factor also assumes that the decline in productivity will be arrested, but that it will remain at a lower level.

The cost per foot drilled for successful gas wells, based on data reported by the Joint Association Survey (JAS) sponsored by American Petroleum Institute, Independent Petroleum Association of America, and the Mid-Continent Oil and Gas Association, are set out on Schedule III-D-6.

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*Docket No. RM75-14.

**On July 27, 1976 the FPC issued Opinion No. 770 which set the national rate for gas dedicated to the interstate market after January 1, 1975. This national rate was set at 142 cents per Mcf. The productivity levels used in determining this rate were 373 Mcf per foot and 279 Mcf per foot. This opinion also set a rate of 101 cents per Mcf for gas sold to the interstate market between January 1, 1973 and January 1, 1975.

There has been a slight increase in the average onshore well depth since the beginning of the 1960's. The offshore average well depth has declined slightly over the same period. (See Schedule III-D-7) As wells are drilled deeper, the cost of the well and the cost per foot drilled are higher, especially for onshore drilling. Schedule III-D-8 shows these costs at different depth intervals for 1974. It can be seen that drilling costs per foot climb steeply after the 5,000 foot mark for onshore drilling. For example, for every increment of 2,500 feet above the 5,000 foot mark, the average cost for onshore drilling increases about 39 percent.

Columns 1 and 2 of Schedule III-D-6 set out the actual reported cost per foot drilled for successful wells, onshore and offshore. Column 3 shows the GNP price deflator, where 1975 equals 100.0. Columns 4 and 5 show the costs in 1975 dollars from which the projected costs were estimated. The projected costs were calculated by a linear regression method. This assumes that the historical trend in drilling costs in real terms will extend into the future. The projected costs are shown as labeled on Sheet 2 of Schedule III-D-6.

As indicated above, onshore and offshore drilling costs were developed separately. The projected costs were averaged with weights developed by the National Petroleum Council*. Offshore drilling is assumed to reach 15 percent of the total gas well footage by 1985

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*NPC, National Energy Outlook, 1972.

and remain there for the entire projected period. This represents a substantial increase over the 1974 level of 4 percent. (See Schedule III-D-9).

Line 2 - Recompletion and Deeper Drilling Costs

The estimates for recompletion and deeper drilling costs are available on an annual basis for 1963-1969 for 23 gas producers responding to the drilling data questionnaire in FPC Docket AR69-1. These expenditures were related to total gas well drilling expenditures reported by the respondents to determine appropriate ratios applicable to total drilling costs. Expenditures for recompletions and deeper drilling ranged from 3 percent of total gas well drilling expenditures in 1963 to 5 percent in 1969. This study used 4 percent (the mid-point) of the gas well cost per foot to estimate the future recompletion costs.

Line 3 - Lease Acquisition Costs

Lease acquisition costs have varied erratically over the years. To a large extent this level depends on the leasing policy adopted by the Government. A summary of the Government's OCS leasing is shown on Schedule III-D-10.

Schedule III-D-11 shows the ratio of the total (oil and gas) successful well costs to the 5-year moving average lease acquisition expenses. There has been a significant increase in this ratio; for example, in 1967, this ratio was .37; however, by 1974 it rose to .87. This ratio is expected to continue to increase to about 1.16, which is used in this forecast for all of the projected years.

The estimate of 1.16 was based on the following assumptions:

a) The projected average cost per foot of successful gas wells for the period 1985-2000 represents a 45 percent increase over the current level. The projected average (1985-2000) total successful well cost is $2,707* x 1.45 = $3,925 million per year.

b) The projected average lease acquisition cost is $4,555 million per year, based on the following assumptions:

1) Six lease sales will be offered each year by the Government.

2) The average size of lease offered for sale will be 800,000 acres.

3) The average price per acre will be $2,200 (1970-1975 average).

4) The average leased/offered ratio will be .384 (1970-1975 average).

5) Non-OCS leasing will be $500 million per year (1972-1974 level.)**

c) The projected lease acquisition cost, $4,555 million per year, divided by the projected total successful well cost, $3,925 million per year, is 1.16.

The projected lease acquisition cost component is therefore, the cost per foot drilled with a one-year lag prior to production multiplied by 1.16.

As explained in Chapter III-C, future lease acquisition expenses are quite uncertain, therefore these have to be considered as best judgement estimates.

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*1974 data (Schedule III-D-11).

**Source: Chase Manhattan Bank, Capital Investment of the World Petroleum Industry, 1974.

Line 4 - Lease Equipment and Related Producing Facility Expenses

A factor of .232 was applied to the cost for successful wells to derive this cost component. The derivation of this factor is shown in Schedule III-D-12.

Line 6 - Dry Hole Cost

Schedule III-D-13 sets out the average dry well depth for each of the years 1961-1974. The onshore wells have been drilled continuously deeper since the early 1960's. The average depth of offshore wells was stable to 1971, then declined through 1974.

Schedule III-D-14 sets out cost per well and cost per foot drilled at different depth intervals in 1974. The cost per foot drilled rises substantially for onshore wells once the well passes the 5,000 foot mark.

The historical cost per foot drilled -- dry holes -- is presented on Schedule III-D-15. The dry hole cost was allocated to gas on the basis of the ratio of the gas well cost to total successful well cost. The costs were projected in a like manner to the successful well costs (i.e., a linear least square line was developed to project the cost per foot of dry wells).

The weighted average cost per foot drilled with a one-year lag, divided by the appropriate high or low productivity factor and multiplied by a factor of 1.12, is projected to represent the dry hole cost and is entered on line 6 of Schedules III-D-3 and III-D-4.

The 1.12 factor adjusts upward the dry hole cost attributed to gas to allow for the greater depth and hence higher cost of gas wells as compared with oil wells. The FPC adopted a constant factor of 1.08 for this adjustment. Foster Associates has updated this factor to a level between 1.12 and 1.28. The low level of this range was assumed for this study for both oil and gas.

Line 7 - Geological, Geophysical, Land Department, Lease Rental and Other Direct Overhead Expenses

This cost component was estimated at 38 percent of the cost of successful wells. The 38 percent is the ratio of the G&G, etc. expense (1969 to 1972) to the successful well costs (1971 to 1974). The 2-year lag allows the time for development. (See Schedule III-D-16) The 38 cents was applied to the cost per foot drilled with a one-year lag prior to production, since geological, geophysical, and other expenses are assumed to take place 3 years prior to production.

Line 8 - Exploration Overhead

The exploration overhead expense is assumed to equal 6 percent of the cost of dry holes plus lease acquisition cost.

Schedule III-D-17 shows the ratio of exploration overhead expense to dry hole costs plus lease acquisition cost from 1967 to 1973. The average for the period was 9 percent; however, dry hole costs and lease acquisition costs are expected to rise faster than exploration overhead expenses, which will keep this ratio at a low level.

Line 10 - Operating Expenses

This cost component includes lease operating expenses, corporate, general, area and district expenses, and miscellaneous lease revenues. This unit cost is projected to remain constant in real terms for the projected period.

Line 11 - Regulatory Expense

This unit cost is forecast to increase from its current level because the cost will be spread over a smaller volume of gas sales; i.e., cost will increase in inverse proportion to the decrease in projected gas production.

TABLE 8

Year	Projected Gas Production Estimated 1/ Production (Tcf)	 Percent of 1975
1975	20.4	--
1985	17.0	83.6
1990	16.0	78.4
1995	15.0	73.5
2000	13.7	67.1

1/ See Supply and Demand for Natural Gas.

For example, in 1985, the regulatory expense would be .20¢* divided by 83.3 percent, or .24¢.

Line 12 - Net Liquid Credit

Condensate and other natural gas liquids are extracted from natural gas after production. This liquid production provides additional revenue for the producer, and this must appear as a credit on Schedules III-D-3 and III-D-4. Schedule III-D-18 sets out the calculation of this credit based on the projected cost of oil.

Line 13 - Return on Working Capital

The return on working capital was calculated from the same formula employed in FPC Opinion No. 699-H, December 4, 1974. However, factors which account for the materials and supplies were updated by the use of the FPC Staff's recommendation as of March 23, 1976.** Schedule III-D-19 shows the derivation of these factors.

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*1975 level reported in FPC Opinion No. 699-H, December 4, 1974.

**Docket No. RM75-14.

Return on working capital equals ((Line 9 x 0.125 x 1.21) + (Line 10 x 0.125 x 1.48) + (Line 3 x 1.5)) x 1.5. The .125 (1.5 months out of 12 months) is the portion of the year which working capital is assumed to be tied up. The 0.15 is the assumed rate of return. And, the other factors, 1.21, 1.48, and 1.5 are the percentages of the cost components, indicated by line number, needed for materials, supplies and/or prepayment expenses.

Line 19 - Total Cost of New Gas

The cost components on lines 1 through 13 of Schedules III-D-3 and III-D-4 were used in a DCF calculation at an internal rate of return of 15 percent to determine the cost of new non-associated gas. The main purpose of the DCF calculation is to estimate the carrying charges on the invested capital. The DCF method sets the discounted net income flow to the discounted costs. In the oil and gas industries there are substantial pre-production costs and a portion of this investment can be immediately amortized according to the Federal tax law. The remainder of the pre-production costs are amortized during the production period.

The short DCF form was used in the calculation which is:

$$\sum_{i=1}^{N} \text{discount factor (mid-point of production year)} \times \text{(price-cost)} = \text{discounted pre-production cost.}$$

Where N equals the operating life of the well.

The following assumptions were made for this calculation:

1) G&G, etc. expenses, exploration overhead, lease acquisition expense, dry hole cost, successful well cost, recompletion and deeper drilling cost, and production facility cost were considered pre-production expenses.

2) The FPC's* "percent expensed" of production costs was used to forecast the level of net investment.

3) An income tax rate of 48 percent was applied.

4) A royalty rate of 16 percent was assumed.

5) State production tax rate of 3.16 percent plus 2.5 cents per Mcf was used in the calculation. (See Schedule III-D-21)

6) The discount factor was the sum of the mid-year discount rates weighted according to gas well depletion curve over 18 years. (No build-up period was assumed.)

The calculation of the required gas price under the DCF method is set out on Schedule III-D-20, Sheets 1 through 10.

Once the price is determined, the cost components on Line 14 (return) and Line 16 (royalty), Line 17 (state production tax) and Line 18 (income tax) of Schedules III-D-3 and III-D-4 can be determined by applying the appropriate tax and royalty rates. Then Line 14, the unit return on investment can be found by netting out the other costs.

5. Major Uncertainties of The Cost Forecast

Set out below are the major uncertainties of this forecast in addition to the level of productivity:

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*Opinion No. 699-H, December 4, 1974.

a) The U.S. Government's method of regulation over natural gas prices is subject to major changes, such as elimination of old gas, initiating new methods of calculating new gas costs, and giving greater emphasis to "economic" factors.

b) The cost per foot drilled for successful wells and/or dry wells may increase at a different rate than previously experienced.

c) Offshore drilling may not reach 15 percent of the total drilling efforts by 1985.

d) Lease acquisition expenditures may vary erratically in the future.

e) New unforeseen technology may be introduced which could affect the cost of finding gas, the drilling cost, or the productivity factor.

f) The income tax rate was assumed at 48 percent.

6. Wellhead Price of U.S. Natural Gas Under Free Market Conditions

The projected wellhead price of natural gas under free market conditions is assumed to approximate the price on a Btu basis of domestic crude oil under the free market case. There are factors which indicate the value of gas should be higher than crude oil and there are factors which indicate the value of gas should be lower than crude oil. Factors which increase the value of gas with respect to other fuels include the fact that gas is the clean burning fuel which has greater versatility for many industrial processes. Furthermore, gas, unlike crude oil, does not incur the substantial cost of refining. On the other hand, crude oil is refined into the gasoline which has a high value and the cost of transporting oil to the burner tip is less than for gas.

For the purpose of this study, it is assumed that these are offsetting factors; therefore, the projected wellhead price of natural gas is set at approximately the domestic oil price expressed in 1975 dollars, as follows:

TABLE 9

PROJECTED PRICE OF DOMESTIC GAS

	Domestic Oil		Domestic Gas	
Year	$/Barrel	¢/MMBtu 1/	¢/MMBtu	¢/Mcf 2/
1985	12.35	213	213	220
1990	13.35	230	230	238
1995	15.35	264	264	273
2000	19.10	329	329	341

1/ 5.8 MMBtu/barrel.

2/ 1035 Btu/cf.

7. Alaskan Natural Gas

It is assumed that deliveries of natural gas from Alaska's North Slope will commence by 1985. Initial deliveries are projected to be between .8 and 1.2 Tcf, building up to 3 Tcf by 1995. It is assumed this gas will be sold in the Lower 48 market comparable with world oil prices; i.e., the delivered price of foreign crude oil plus the cost of refining the crude into distillate fuel oil, as follows:

TABLE 10

PROJECTED ALASKAN GAS PRICE

	Delivered Foreign Crude Oil Price		Cost of Refining	Value of Alaskan Gas (Lower 48 City Gate)
Year	$/Barrel 1/	¢/MMBtu 2/	¢/MMBtu	¢/MMBtu
1985	11.75	203	40	243
1990	12.75	220	40	260
1995	14.75	254	40	294
2000	18.50	319	40	359

1/ Chapter III-B and C.

2/ 5.8 MMBtu/barrel.

8. Canadian and LNG Imports[*]

Canadian and LNG imports are both projected to be marketed in the U.S. at equivalent parity with world crude oil prices, as shown on Table 11.

TABLE 11

PROJECTED CANADIAN AND LNG PRICES - CITY GATE
(¢/MMBtu in 1975 Dollars)

1985	243
1990	260
1995	294
2000	359

9. Consumer Gas Prices

The average 1975 consumer prices for natural gas by cities representing the census regions are presented on Schedule III-D-22, Sheet 1 of 2, by consuming sector. The general location of the cities is shown on the map at Schedule III-D-23.

All of these prices, except as noted, were calculated from rate schedules of local gas distributors. The residential price represents residential spaceheating. The volumes used for the calculations were based on the seasonal degree day of the particular region. The average price for all residential gas usage[**] would be somewhat higher. The commercial gas price is the price for users consuming 70 Mcf per month. The industrial gas price is an average price at three consumption volumes: 5,000 Mcf, 15,000 Mcf, and 45,000 Mcf per month.

Schedule III-D-22, Sheet 2 of 2, presents the 1975 electric power plant prices for gas by census region. The source of these data is the Form 423 filed by electric utilities with the FPC.

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[*] The projected cost of SNG is estimated in Chapter III-F.

[**] Base load and spaceheating.

In projecting retail prices there remains the need to estimate future trends in transportation and distribution costs.

Two simplifying assumptions are used in this analysis:

- Gas pipelines and distributors will not importantly change their rate structure.
- The impact of future increases in the cost of gas to pipelines and distributors is distributed evenly between the census regions.

Another assumption is stipulated by EPRI -- the future cost and price projections are to be stated in 1975 dollars. This means, of course, that future inflation is not a part of the analysis. A final assumption is that increases in the cost of capital will level off and therefore not cause further changes in the cost of transportation and distribution.

There remains, then, future changes in these costs caused by declines in load factor and by increased real costs of purchased fuel.

As to load factor, the stipulated EEI base case demands (Table 5) show a 50 percent increase in gas throughput from 1975 to 2000. (Even EEI's low case shows 2000 gas demand at approximately the 1975 level.) While Foster Associates is unable to reconcile the supply required to meet this demand, nevertheless, such a demand suggests improved load factors for distributors and much, if not all, of the national pipeline network.*

Thus, the major cost increase for transportation and distribution will come from fuel utilization. In recent years gas pipelines and distributors have consumed about 7 percent of the gas throughput for compressor fuel and other company uses. Thus, pipeline and distribution costs will increase

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*Because much of the increased supply presumably will be imported, or come from coal gas, it is plausable to expect much of the interstate trunkline system out of the Southwest to be utilized by exchange, or, if necessary, by conversion to liquid transportation.

by 7 percent of the projected increased cost of purchased gas , as follows:

TABLE 12

PROJECTED INCREASED COST OF TRANSPORTING & DISTRIBUTING GAS - 1975 DOLLARS

	¢/MMBtu	
	Price Regulation Case	Free Market Case
1985	7	12
1990	9	14
1995	13	16
2000	16	21

Based on the above analyses and assumptions, the retail prices of gas can be forecast. The 1975 U.S. average price of natural gas for three consuming sectors were:*

Residential	-	170¢/MMBtu
Commercial	-	141¢/MMBtu
Industrial	-	99¢/MMBtu

If the projected increase in transportation and distribution is added to the forecast of U.S. weighted average price of gas (Table 6) the projected retail prices would be as follows:

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*Source: AGA, Quarterly Financial Review, June 1976.

TABLE 13

PROJECTED RETAIL PRICE OF GAS
(¢/MMBtu)

		Price Regulation Case	Free Market Case
Residential	- 1985	278	356
	- 1990	314	379
	- 1995	364	416
	- 2000	408	486
Commercial	- 1985	249	327
	- 1990	285	350
	- 1995	335	387
	- 2000	379	457
Industrial	- 1985	207	285
	- 1990	243	308
	- 1995	293	345
	- 2000	337	415

By the use of the several assumptions set out above, the projected retail prices can be determined on a regional basis. These prices are presented on Schedule III-D-24, Sheet 1, for the residential, commercial, and industrial sectors; and on Schedule III-D-24, Sheet 2, for the electric utility power plants.

10. Major Uncertainties of the Forecast

Many of the major uncertainties and problems of forecasting natural gas prices to the year 2000 have been covered in the preceding sections. Other major concerns bear emphasizing here.

a) The future method of field price regulation for production in the Lower 48 is highly uncertain. In this report, it is assumed that the current FPC type of regulation will continue to 2000. If future regulation relies more on economic factors, then field prices will probably be higher.

b) Much of the different sources of gas supply are projected to be priced at parity with oil prices. All the uncertainties regarding the oil price forecast apply to these gas prices (see Chapter III-B and C).

c) To derive the future retail gas price on a regional level, it was necessary to make simplifying assumptions. While it is possible to forecast more accurate regional prices, it is beyond the scope of this study. The result would be an uneven increase in gas prices as among regions, but similar when averaged to the national basis as shown here.

d) It is beyond the scope of this study to predict future sources of supplies for each census region. The different sources of supplies will not be spread evenly over the entire country unless by Government regulation. This assumption becomes less important in this study as the projected prices of the different sources of gas supply merge to oil prices.

e) Political, economic, financial, and/or gas supply problems may dictate shifts in the rate structures of gas pipelines and distributors. The more apparent shift, according to present curtailment plans, would be away from large boiler fuel markets.

f) This analysis does not take into account expiring contracts for old gas which, under current FPC regulation, would become new gas and therefore command a higher price.

g) If gas supply, counter to the EEI analysis, continues to decline then the cost of transportation and distribution will rise because of decreasing load factors.

11. Range of Uncertainty in Projecting Gas Prices

Substantial uncertainties attend the projected gas prices. Two of these uncertainties were recognized in the analysis -- the high and low productivity case for calculating the cost of new gas, and the regulated price case versus the free market case. These ranges are necessary but not sufficient to cover the total degree of uncertainty in the projected gas prices.

Therefore, ranges of uncertainty were developed on a judgemental basis. The following table sets out a range which more closely approximates most of the uncertainties of projecting gas supply prices:

TABLE 14

PROJECTED GAS SUPPLY PRICE RANGE
(¢/MMBtu)

	1985	1990	1995	2000
Low Range	142	144	147	150
Base Case 1/	186	213	254	306
High Range	289	323	358	409

1/ Average of regulated price case and free market case.

The lower portion of this range represents the 1976 field price for new gas. This price level was used because proven reserves are expected to be essentially depleted by the beginning of the projected period. This lower range is expected to increase over time because a larger volume of more expensive supplemental gas will replace the Lower 48 States production. The price of this supplemental gas is assumed to be the price of the lower range of the crude oil price on an equivalent Btu basis (see Chapter III-C).

The upper level of the gas supply price range is the upper level of the crude oil price range (Chapter III-C) on an equivalent Btu basis.

The percentage variations from the most likely supply price are set out on the following table. These variations would apply to retail prices because they represent the wholesale price of gas.

TABLE 15

PERCENT VARIATION FROM THE BASE CASE PRICE TO REFLECT THE UNCERTAINTY OF THE SUPPLY PRICE PROJECTION

	1985	1990	1995	2000
Low Range	-24%	-32%	-42%	-51%
High Range	+55%	+52%	+41%	+34%

It is interesting to note that in 1985 the range skewed to the upper side; however, by the year 2000 the opposite is true. Also, as to be expected, the variation increases as one progresses in time.

To the uncertainty of the gas supply price forecast there is also a lesser, yet additive, uncertainty attending the transportation and distribution cost estimates.

E. U.S. COAL

1. Introduction

United States coal resources have been given a significant role in this country's future supply of energy by energy policy makers, primarily because of a substantial resource base position relative to other domestic fuels, and the presence of cartel controlled foreign oil supplies. This new level of significance in the U.S. energy economy places coal in a dynamic posture with respect to both supply and utilization.

The purpose of this section is to analyze and estimate the price of coal from a supply/cost viewpoint for the period 1985 to 2000; to develop an appropriate costing methodology; to estimate the projected cost of coal at the mine for each of the designated producing regions; and to develop the projected prices in consumer markets after a consideration of direct market influences.

Three producing regions, which encompass all major coal basins, are utilized as a basis for projecting FOB mine costs. These are -- (1) the Eastern region; (2) the Mid-Continent region; and (3) the Western region, which includes the Northern Great Plains coal province and the Rocky Mountain coal province. Schedule III-E-1 shows the coal provinces making up these producing regions.

Within each region, the coal is classified by type for which costs are projected, as follows:

TABLE 1

REGIONAL COAL TYPES

Coal Rank/Product	Producing Region		
	Eastern	Mid-Continent	Western
Bituminous			
High Sulfur Steam Coal 1/	X	X	
Low Sulfur Steam Coal	X		X
Metallurgical Coal	X		X
Subbituminous Steam Coal 1/			
Lignite		X	X

1/ Could also be used as feedstock for synthetic fuel plant.

2. Determinants of Long-Run Coal Costs

A projection of coal prices at the mine and delivered to end-use consumers from 1985 to 2000 must be considered in the context of a long-run analysis. Two key factors will be considered -- producer response and the reserve base. Producer response is relevant since it is the reaction of producers to anticipated demand that determines the size and type of supply ultimately produced. This demand is a driving force behind the supply response. Therefore, while supply and cost are the major consideration of this report, demand must be taken into account in order to establish the relation between cost and price. This has been accomplished by relating coal supply to the three energy demand cases as set out in the EEI report. These alternate demand cases, therefore, provide a basis for determining the level of supply which, in turn, will be affected by the level and nature of costs. These, in turn, will be dependent upon time horizons.

The time horizon for this study is sufficiently long to allow for the consideration of alternate technologies in coal production which, in turn, could affect the future structure of costs. In addition, the real prices paid for factor inputs will change over time, thereby affecting the level of costs.

The level of costs in a producing region will also be affected by the reserve base at a particular point in time. Production costs from mature producing areas will tend to increase over time as the most accessible portions of the reserve base are depleted. Alternatively, in those producing regions where coal reserves are large and have not been developed to any significant degree, the cost of supply will be lower. The absolute size of the resource base will also have an overriding influence on the long-run supply price. A resource base that is sufficiently large and well defined will exhibit supply prices which will affect the cost of production in the long run, other factors remaining constant. This has been historically true of coal prices although in recent years, particularly 1974, prices deviated significantly from costs due primarily to short-run factors.*

In actuality, long-run costs will be determined by the simultaneous interaction of all of the above factors. The present analysis will rely on a stepwise procedure which examines demand, supply, and cost, as follows:

The projected demand, supply, and reserve base are first examined in order to gauge the incremental supply for the major producing regions. The projected cost is then determined for the incremental mine which would provide that supply. Because of the uncertainty attending all of these factors, it is impossible to determine the projected costs with precision. Rather it is more appropriate to indicate what the likely range of cost will tend to be over the forecast period.

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*For a discussion of these short-run influences on price, see <u>A Study of Coal Prices</u>, Council on Wage and Price Stability, March 1976.

3. Coal Supply and Demand

The projected cost of coal is based on a determination of what the incremental regional supply will be over the forecast period. The determination of incremental supply will be based upon an examination of projected requirements (demand), and the projected supply.

a) Projected Demand

As stipulated by EPRI, the demand analysis in this study is to play a subsidiary role to that of projected prices. In this regard, the EPRI contract required that the total energy demand projections as set out in the EEI report be utilized by the contractor. Comprising this total energy demand projection are projections for coal as well as other fuels which are in turn, supported by a number of assumptions. Even though they are lower than other recent projections of coal consumption, the impact on the determination of incremental supply was not considered critical.

A comparison of the EEI projected coal requirements with those of the Department of Interior and the Federal Energy Administration (FEA) is set out in Schedule III-E-2. Since the EEI projection does not include exports, both the Interior and FEA projections were adjusted to exclude exports. In addition, industrial non-fuel uses were also excluded from the Interior projection. On this basis, the FEA projection presents the most optimistic outlook for coal consumption. The Interior projection is also higher than the EEI projection, although the rate of growth in consumption is similar to both the high and intermediate growth cases for EEI.

In order to determine the impact of demand on the major supply regions, it was necessary to estimate the long-run regional demand for coal. The regional projections were tied to the EEI national projections in order to maintain internal consistency, and were developed separately for each end-use sector. The projection for the electric utility sector was based upon planned capacity additions as submitted to the Federal Power Commission (FPC). The industrial sector was based upon projections of industrial growth by the Department of Commerce, while regional consumption by the residential-commercial sector was assumed constant over the forecast period. Schedule III-E-3 sets out the regional projected coal consumption for these three end-use sectors. It is to be noted that projected regional coal requirements for coal based synthetics have not been included since the location of these plants will depend in part upon the demand structure of alternate fuels.*

Having projected regional coal requirements, the next step is to determine what the probable allocation of regional coal supply to meet these requirements will be over the forecast period.

b) Current Regional Production and Distribution

During 1974 the distribution of coal production was as follows:

TABLE 2

1974 REGIONAL COAL PRODUCTION
(Million Tons)

	Producing Region			
Mining Method	Eastern	Mid-Continent	Western	Total
Underground	212.4	54.7	10.2	277.3
Surface	165.4	95.4	65.3	326.1
Total	377.8	150.1	75.5	603.4

Source: U.S. Bureau of Mines

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*The exclusion will not seriously affect the determination of long-run incremental supply since, for the most part, synthetic fuel plants will be located at the mine site and would not be competing for alternate supply sources as would the primary end-use sectors.

The Eastern producing region accounted for approximately 63 percent of total production, while the Mid-Continent and Western regions accounted for approximately 25 and 12 percent, respectively. Underground mining accounted for approximately 56 percent of total Eastern production, while surface production was predominant in both the Mid-Continent and Western regions, accounting for 64 and 86 percent of total regional production, respectively.

The geographic market shares using a Census Region basis, for each of the major producing regions as of 1975 is shown in Table 3.

TABLE 3

1975 GEOGRAPHIC MARKET SHARES
(Percent)

	Producing Region			
Census Region	Eastern	Mid-Continent	Western	Total
New England	100.0			100.0
Middle Atlantic	99.9		0.1	100.0
South Atlantic	90.1	9.9		100.0
East North Central	54.0	35.0	11.0	100.0
East South Central	48.7	51.0	0.3	100.0
West North Central	3.9	54.8	41.3	100.0
West South Central	6.0	93.8	0.2	100.0
Mountain		0.7	99.3	100.0
Pacific			100.0	100.0
Total U.S.	56.4	28.7	14.9	100.0

Source: U.S. Bureau of Mines, Mineral Industry Surveys, Bituminous Coal and Lignite Distribution.

The Eastern producing region dominates supply to the East Coast markets, and also has a significant share of the East Central markets. The Western producing region dominates supply to the Mountain and Pacific markets and also has a significant share of the West North Central markets. The Mid-Continent producing region dominates only the West South Central market, but has a significant share of the East Central and the West North Central markets.

There is a trend away from distinct geographic coal markets for Eastern and Western coal. Regional supply competition may play an increasing role in determining the future market structure. It is a well known fact that the growth of Western coal production has been due to the need to comply with SO_x regulations. Experience gained in burning Western type coals will serve to establish this source of supply as a viable alternative on solely a Btu basis. In order to determine what impact this may have, it is necessary to look at projected supply trends for these producing regions.

c) Projected Supply

The purpose of this section is to determine the probable structure of regional coal supply based upon available studies and the projected regional coal requirements. The reasonableness of the projections will then be assessed in terms of the reserve base.

A first indication of the prospective regional supply structure is provided by a survey of coal mine expansion plans from 1975 to 1985 prepared for FEA*. The survey was based on the following assumptions:

1) The Clean Air Act amendments proposed by the Administration will be enacted.

2) Capital will be available for the projected expansion.

3) No unreasonable surface mining legislation will be enacted.

4) A viable Federal coal leasing program will allow development of Western coal.

5) Realistic means of complying with the National Environmental Policy Act (NEPA) will allow energy development without undue delay or restraint.

6) Adequate transportation will be available.

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*Statement of John Corcoran, Chairman of FEA Coal Advisory Committee, June 1975.

These assumptions and therefore the survey could be considered optimistic. The period covered by the survey is significant in terms of regional coal development since the effects of both air quality regulations and delayed nuclear power plant construction schedules may have run their course. Thus, the pattern of regional supply structure that emerges over this period may not change significantly to the year 2000. The results of this survey are shown in Table 4 in terms of the major producing regions:

TABLE 4

SURVEY OF COAL CAPACITY ADDITIONS, 1975-1985

Region	Million Tons	Percent
Eastern	159.9	29.9%
Mid-Continent	104.5	19.6
Western	269.6	50.5
Total	534.0	100.0

Source: FEA Coal Advisory Committee.

It is apparent that the Western producing region will contribute significantly to future supply expansion. By adding these capacity expansions to the 1974 regional production, an illustrative distribution of 1985 coal production can be developed as shown in Table 5.

TABLE 5

1985 REGIONAL SUPPLY STRUCTURE BASED ON CAPACITY ADDITIONS[1/]

Region	Million Tons	Percent
Eastern	537.7	47.3%
Mid-Continent	254.6	22.4
Western	345.1	30.3
Total	1,137.4	100.0

1/ 1974 production plus 1975-1985 expansion.

Another view of the prospective regional structure of coal supply is provided by the FEA projections, which are set out in Table 6.*

TABLE 6

FEA - PROJECTED REGIONAL COAL PRODUCTION[1/]
(Million Tons)

Regional	1985	Percent	1990	Percent
Eastern	505	48.6	545	41.7
Mid-Continent	186	17.9	207	15.8
Western	349	33.5	555	42.5
Total	1,040	100.0	1,307	100.0

1/ Reference Scenario.

The FEA regional distribution of production in 1985 is similar to that developed for capacity additions plus production. FEA indicates that most of the growth in coal production to 1985 will be due to the demand for low sulfur coal. Thus, of the 1985 production, approximately 46 percent (476 million tons) is estimated by FEA to be low sulfur steam coal.**

Implicit in the production projections of FEA is the assumption that coal reserves are adequate to meet demand. Hence, projected national production will approximately equal demand. This is also true of the Interior Department projection.***

In light of the above data, and for the purposes of developing an illustrative supply projection, it will be

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*<u>1976 National Energy Outlook</u>, Federal Energy Administration, February 1976.

**FEA is careful to point out that the regional production estimates as well as those for low sulfur production are approximations rather than precise calculations due to the sensitivity of supply to tradeoffs in delivered costs plus scrubbing costs.

*** <u>United States Energy Through the Year 2000</u>, Department of Interior, December 1975.

assumed that supply will equal demand over the forecast period for each EEI demand case. The projection is considered illustrative since cost was not explicitly taken into account, thus it was not possible to determine precise market shares for each supply region. Rather, the development of the projection was based on the historic market shares, plus assumptions concerning the importance of Western coal in meeting low sulfur coal requirements in those regions where both low sulfur Eastern and low sulfur Western coals would be alternative sources of supply.

The purpose of this analysis is to gain insight as to how the regional supply changes under the three EEI demand cases and with alternative assumptions concerning Western coal supply.

Schedule III-E-4 sets out the projected regional supply under each EEI demand case. The demand cases utilized are those set out in Schedule III-E-3, which estimated regional demands for steam coal only. Thus, the projected regional supplies exclude export coal, metallurgical coal, and coal feedstocks for synthetic fuel production. This adjustment is reflected in the 1974 regional production data shown in Column (1) of Schedule III-E-4.*

Two supply cases (I and II) are shown for Demand Cases A and B while, under Demand Case C, a third separate supply Case III is projected. Supply Case I assumes moderate expansion of Western coal production. Supply Case II assumes relatively rapid expansion of Western coal production, while Supply Case III assumes slow expansion of Western coal production.

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*During 1974 metallurgical and export coal, produced primarily in the East, amounted to 139 million tons.

The Case I and Case II supply projections were based upon the 1975 market shares with respect to each production region. These were applied to the regional demand projections set out in Schedule III-E-3 and adjusted for low sulfur coal demands, which were estimated for 1985 from projections developed by FEA*. The proportion of low sulfur coal required by utilities in 1985 as estimated by FEA is set out in Table 7.

TABLE 7

SULFUR CONTENT OF UTILITY COAL
1985 REFERENCE SCENARIO, $13 OIL IMPORTS
(Percent of Regional Coal Consumption)

Region	High Sulfur	Low Sulfur
Northeast	83.2	16.8
Middle Atlantic	58.7	41.3
South Atlantic	61.4	38.6
East North Central	55.1	44.9
East South Central	55.7	44.3
West North Central	48.1	51.9
West South Central	42.2	57.8
Mountain	34.1	65.9
Pacific	100.0	
National	55.7	44.3

Source: FEA, <u>1976 National Energy Outlook</u>.

For Case I it was assumed that Western coal would supply one-half the requirements for low sulfur coal in those markets where Eastern and Western sources would be viable alternatives.** For Case II it was assumed that Western low sulfur coal would supply 100 percent of the low sulfur coal requirements in the East North Central market region. This procedure was carried

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*<u>1976 National Energy Outlook</u>, FEA February 1976.

**The East North Central and East South Central regions.

out for each of the forecast years, under the assumption that all incremental demand would be primarily low in sulfur content. This appears reasonable since most increased demand would be coming from large industrial users and power plants which would need to comply with new source performance standards. The same procedure was utilized for both Demand Cases A and B.

Supply Case III is developed for Demand Case C where domestic demand decreases over the forecast period. Under this supply case it is assumed that up to 1985 Eastern coal production maintains its historical market share, while Western coal production increases its market share due to low sulfur coal requirements. The Mid-Continent region experiences only moderate growth. After 1985 it is assumed that production declines would occur in the Eastern and Mid-Continent regions, while production would remain constant in the Western region.

The three supply cases indicate that under Case I the Eastern region remains the major supply area, while under Case II conditions the Western region becomes the dominant source of supply. Table 8 sets out the regional share of production for each supply case under Demand Cases B and C.*

TABLE 8

DISTRIBUTION OF REGIONAL SUPPLY UNDER
ALTERNATE EEI DEMAND CASES B AND C
(Percent)

	1974	1985			2000		
Region	(Actual)	I	II	III 1/	I	II	III 1/
Eastern	53.9	50.8	43.7	53.8	49.3	39.6	53.8
Mid-Continent	31.2	23.3	23.3	26.1	18.2	18.2	25.2
Western	14.9	25.9	33.0	20.1	32.5	42.2	21.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0

1/Demand Case C only.
Source: Schedule III-E-4.

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*The distribution of regional supply for Supply Cases I and II would be similar under Demand Case A.

Table 9 sets out the rates of growth over the forecast period for each of the supply cases.

TABLE 9

COMPARATIVE ANNUAL RATES OF GROWTH UNDER ALTERNATE SUPPLY CASES

(Percent)

Supply Case	Supply Region	1974-1985	1985-2000
I[1/]	Eastern	2.8	1.8
	Mid-Continent	0.7	0.4
	Western	8.8	3.6
II[1/]	Eastern	1.4	1.4
	Mid-Continent	0.7	0.4
	Western	11.2	3.8
III[2/]	Eastern	2.8	(0.3)
	Mid-Continent	1.2	(0.6)
	Western	5.7	-0-

[1/] Based on Demand Case B.
[2/] Demand Case C only.
Source: Schedule III-E-4.

Growth in coal supply is higher for all regions in the 1974-1985 period than the 1985-2000 period. This is due primarily to the increase in coal consumption from new capacity of electric utilities and the lag in the growth of nuclear power. The slower growth in coal supply from 1985 to 2000 stems from the growth of nuclear power inherent in the EEI demand cases.

On a regional basis, Western supply shows the highest rate of growth over both the 1974-1985 period and the 1985-2000 period. This latter period exhibits a growth pattern for the Western region which portends the maturing of this producing area. The Eastern region displays moderate to low growth over the two periods under Supply Cases I and II and a slight decline in supply under EEI Case III demand.* The Mid-Continent region exhibits the lowest rate of growth under all supply cases, due primarily to the assumed loss of markets to Western and Eastern low sulfur coals.

The projected regional rates of growth in supply under Cases I and II as shown in Table 9 for the 1974-1985 period are lower than those projected by FEA, although the regional pattern of growth is similar.** The primary reason, of course, is the lower level of demand projected in the EEI study. FEA projects a high rate of growth for the Western region, a moderate rate of growth for the Eastern region, and a low rate of growth for the Mid-Continent region. The specific growth rates are set out in Table 10.

TABLE 10

REGIONAL SUPPLY GROWTH
PROJECTED BY FEA 1/
(ANNUAL RATE - PERCENT)

Region	1974-1985
Eastern	3.7
Mid-Continent	1.9
Western	15.5

1/ Reference Scenario

d) Determination of Incremental Mining Capacity

Given the projected regional supply set out above, the long-run incremental cost will be dependent upon the type of production that is utilized in each region to bring forth such supply. Such a determination can be made by examining the coal resource base.

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*The inclusion of metallurgical and export coal would result in stable to slightly increasing supply for the Eastern region.

***National Energy Outlook*, FEA, February 1976.

Table 11 sets out the remaining resource base for the United States.

TABLE 11

ESTIMATED REMAINING COAL RESOURCES OF THE UNITED STATES, JANUARY 1, 1974*

Category	Billions (10^9) of Short Tons
1. Identified (measured, indicated and inferred) resources:	
A. Reserve base........................	424
B. Additional identified resources......	1,307
C. Total identified resources...........	1,731
2. Hypothetical resources:	
A. 0-3,000 ft. overburden...............	1,849
B. 3,000-6,000 ft. overburden...........	338
C. Total hypothetical resources.........	2,237
3. Total remaining resources.................	3,968

Source: Coal Resources of the United States, January 1, 1974, Geological Survey Bulletin 1412.

Identified resources comprise approximately 44 percent of the total remaining resource base. These identified resource estimates are based on existing geologic and mine data and therefore provide an indication of that coal which will most likely comprise future supply. This is not to say that some production would not come from the hypothetical resource base, but due to the size and extent of the identified resources, most production would derive from this base. One simple measure which serves to place the size of the identified resources into perspective is a reserve life index based on current rates of production. Using the 1974 production level of 603 million tons, the identified resources would have a remaining life of approximately 2,900 years. Using this basic measure of adequacy, it can be assumed that in all likelihood projected supply would derive from this portion of the resource base.

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*Excludes speculative resource.

Detailed data with respect to the identified resource base is shown on Schedule III-E-5. This schedule sets out, on a state and regional basis, the remaining identified coal resources by rank of coal. Table 12 summarizes the distribution of identified resources on a regional basis.

TABLE 12

DISTRIBUTION OF IDENTIFIED COAL RESOURCES
(Percent)

Supply Region	Rank				Total
	Bituminous	Subbituminous	Lignite	Anthracite	
Eastern	34.8	0	0.5	97.4	16.2
Mid-Continent	38.4	0	2.2	2.2	17.2
Western	26.8	100.0	97.3	0.4	66.6
Total	100.0	100.0	100.0	100.0	100.0

Source: Schedule III-E-5.

Table 12 indicates that the Western region has the largest share of the identified coal resource base, primarily comprised of subbituminous and lignite type coals.

Within the identified coal resource category is the reserve base which represents that portion of the identified resources most amenable to current development given the present mix of mining technology and economic conditions. Schedule III-E-6 sets out the reserve base for each state and region by type of mining stratified by sulfur category.

Again, using the reserve life index measure based upon 1974 production, the coal reserve base has a remaining life of approximately 720 years. Even if one makes the assumption that all production comes from underground mining and includes recovery losses of

50 percent, the remaining life of reserves is still in the order of 357 years. Thus, it is apparent that prospective supply will come primarily from this portion of the identified resource base.

Assuming therefore that production over the forecast period will come from the presently identified reserve base, an estimate of depletion was made to determine the impact of Supply Cases I and II on the regional reserve bases. Since Supply Case III deals with the low demand case, it was believed the conclusions reached for under the other two cases would also be applicable to that supply case. Schedule III-E-7 sets out the results of this calculation. From these data, inferences can be made concerning incremental mining capacity to be developed over the forecast period. It should also be noted that in order to determine the depletion rates, it was assumed that the mining mix in each region remained the same as 1974. Thus, we are implicitly assuming constant costs and technology. For the purposes of this analysis, the impact of the assumption would not materially affect the conclusions reached.

As shown in Schedule III-E-7, underground reserves will comprise approximately 90 percent of the remaining reserves in the Eastern supply region at the end of the forecast period. Therefore, it is assumed that underground mining will form the incremental capacity over the forecast period. Any Federal enforcement of surface mine regulations with limitations on mining above certain slope-angles would tend to enforce this assumption. The Council on Environmental Quality estimated that approximately 30 percent of strippable reserves occurred in areas with slopes greater than 20 degrees.*

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* Coal Surface Mining and Reclamation, Council on Environmental Quality, 1973.

Thus, to the extent that Federal regulation prohibits mining on slopes of 20 degrees and greater, the availability of strippable reserves would be further reduced.

As a further indication that underground mining will provide the incremental growth to coal supply, data compiled on mine capacity by Coal Age Magazine* indicates that for the Appalachian region, 92 percent of incremental capacity over the 1975-1985 period will be mined by underground methods.

In the Mid-Continent region, recoverable strippable reserves at the end of the forecast period will account for only 23 percent of total reserves. Thus, it appears probable that underground mining will also provide incremental growth in supply in this region. This cannot be stated as conclusively as with respect to the Eastern region, however, due to the fact that reserve base in this region is diverse with respect to type of coals found there (bituminous, lignite) and geographic occurrence, (i.e., three distinct coal basins). This fact shows up in the Coal Age Survey referred to above. For the Mid-Continent region as a whole the survey shows that underground mining will add approximately 42 percent to incremental capacity over the 1975-1985 period. However, when the data are stratified as to bituminous and lignite production, the contribution of underground mining capacity increases to 58 percent. Therefore, for the Mid-Continent region, it is assumed based on the above data, that underground mining will provide the incremental supply over the forecast for bituminous coal, while surface mining will provide the relevant capacity additions for lignite production.

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*February 1976, pp. 106-118.

The Western region is also heterogeneous with respect to the type of coal found there. This includes lignite, subbituminous, and bituminous coal. Presently, surface mining is the predominant form of production due to the large occurrence of this type of reserve. Over the forecast period, as shown on Schedule III-E-7, strippable reserves will still comprise approximately 43 percent of total recoverable reserves in the area. Thus, it can be inferred that surface mining will continue to provide the incremental capacity over the forecast period.

The *Coal Age* data indicate that from 1975-1985 surface mining will provide 96 percent of the incremental capacity. A qualification must be made, however, with respect to the type of coal produced. Stratifying bituminous coal capacity from subbituminous and lignite capacity, the *Coal Age* data show that approximately 75 percent of the bituminous coal will be produced by underground mining. Therefore, for the Western region, incremental supply will derive from surface mining for lignite and subbituminous coal and underground mining for bituminous coal.

In summary, then, over the forecast period, incremental supply will derive from the following mine types in each supply region:

-	Eastern Region	Underground mining
-	Mid-Continent Region	Underground mining - Bituminous coal Strip mining - Lignite
-	Western Region	Strip mining - Subbituminous-Lignite Underground mining - Bituminous

4. Costs for Major Coal Supply Regions

The above analysis determined the incremental capacity for each of the major supply regions over the forecast period. The cost of this incremental capacity will now be determined. The approach utilized relies on estimating the current cost for each mine type delineated above. Projected costs are then developed based upon an evaluation of prospective factor costs and probable technology changes.* The model mine cost data developed by the Bureau of Mines form the basis for determining the current costs.** There are some drawbacks in utilizing the Bureau of Mines data, the most obvious being that the data are developed for hypothetical mining conditions.*** However, for the purpose of a long-run projection, their use has value since, by the nature of the analysis, one is implicitly assuming the most efficient type of mining will be employed. It is believed that the dangers are more serious for short-run projections where one must deal with a largely fixed stock of capital. Finally, it must be pointed out that on a national basis, there is a paucity of data readily available with respect to both mining conditions and actual mining costs; thus, the necessity to rely on Bureau of Mines data for the purpose of this study.

Below, the methodology and assumptions will be discussed initially, followed by a discussion of current model mine costs and those factors which affect prospective costs, and finally, the projected costs for each supply area will be set out.

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*Projected costs are set out in 1975 dollars.

**U.S. Bureau of Mines I.C. 8682, 8689, 8661, 8535.

***For discussion of these drawbacks, see Economic Analysis of Coal Supply: An Assessment of Existing Studies, EPRI May 1975.

a) Methodology and Assumptions

The projection of coal costs is based on the selection of an assumed probable mine size that will supply the incremental capacity determined in the prior section; the determination of the current cost of the selected mine sizes based on the Bureau of Mines model mine cost data; the development of a costing equation which identifies the fixed and variable components of mining costs and relates these to productivity; a projection of productivity; and assumed adjustments for the regional mining conditions and types of coal produced in each region.

Ideally, it would be desirable to develop a cost model which would be completely adjustable to changes in mine size, technology, and mining conditions, since in the long run significant changes in the reserve base (i.e., mining conditions) could affect both the size of mine developed as well as the type of technology which is employed to produce the coal. This would be possible if complete data existed for both reserves and mining operations indicating such parameters as coal seam depth, thickness, mine capacity, mine depth, roof conditions, and age of mine. Unfortunately, these data do not exist, and although an attempt was made to identify how such parameters would affect mining costs for this study, no conclusive costing adjustments could be attained.

In lieu of such a costing model, it became necessary to rely on a more standard approach to projecting mining costs. This was accomplished by assuming certain mine characteristics would be representative of regional supply capacity over the forecast period. The effect of changes in technology and reserve base changes are reflected through productivity changes, which are projected under two scenarios. These productivity changes are incorporated into the costing model by deriving for each mine type a fixed cost component and a variable cost component, which is a function of projected productivity. The cost components for each mine type are also adjusted to reflect changes in the level of cost, in terms of 1975 dollars, over the forecast period.

Assumptions germane to the projection are set out below:

1) Regional Coal Types

For the Eastern supply region, cost projections will be made for two types of coal: high sulfur bituminous and low sulfur bituminous, which includes metallurgical coal. In the Mid-Continent region, cost projections will be made for two types of coal: high sulfur bituminous coal and low sulfur lignite. In the Western region, three types of coal will be projected, all assumed to be low in sulfur content. These are bituminous coal, including metallurgical grades, subbituminous coal and lignite.

2) Regional Mining Characteristics

Eastern Region - It is assumed that a one million ton per year mine will be representative of the incremental underground mine capacity to be added over the forecast period. It is further assumed that all low sulfur metallurgical grade coal will be washed while high sulfur coal will not. It is also assumed that low sulfur coal will come from deep mines operating at a depth of approximately 1,000 feet, while high sulfur mines will operate at intermediate depths of approximately 500 feet.

Mid-Continent Region - For the high sulfur bituminous coal, it is assumed that mines with a capacity of approximately one million tons will be representative of incremental underground mine capacity. It is also assumed that these mines will operate at intermediate depths (i.e., approximately 500 feet). For low sulfur lignite, it is assumed that mines with a capacity of approximately 9 million tons annually will be representative of incremental surface mine capacity.

Western Region - It is assumed that bituminous coal will come from underground mines with a capacity of one million tons, subbituminous coal will come from surface mines with a capacity of 7 million tons per mine, and lignite will come from surface mines with a capacity of 9 million tons per mine. It is assumed that preparation will be required for bituminous coal used for metallurgical purposes.

b) Current Model-Mining Costs

As stated above, the starting point for projecting mining costs is to establish the current cost structure for the different types of mines delineated in Section 3. Current cost structures are set out for underground mining using continuous as well as long-wall mining technology, and also for surface mines. All costs are stated on a 1975 basis. In some instances, it was necessary to update those cost studies which had been completed before 1975. Where this was necessary, capital and operating costs, excluding labor, were escalated using the appropriate components of the Bureau of Labor Statistics (BLS) Wholesale Price Index (WPI). Labor costs were escalated using the adjustments found in the United Mine Workers wage contract.*

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* National Bituminous Coal Wage Agreement of 1974, effective December 6, 1974.

In addition, where necessary, all costs were adjusted to reflect a 15 percent DCF rate of return.*

c) Underground Mining

The cost structure for continuous underground mining was based on the Bureau of Mines model mine with an annual output of approximately one million tons per year from both a 48-inch seam and a 72-inch seam.** Since both studies were based on 1975 costs, no adjustments to the data were deemed necessary. Schedule III-E-8, Parts A and B, set out the cost structure for both type mines. In addition to the continuous type underground mines, the present and prospective impact of long-wall mining warranted research into the cost of this type of mining. It was found that the Bureau of Mines was currently developing model mine cost estimates for the long-wall mining system. These estimates were obtained from the Bureau of Mines and are also set out on Schedule III-E-8, Part C. Again, no adjustments have been made to the data since the costs were estimated as of 1975. The long-wall mining costs were developed for a 3.1 million ton per year mine, although the seam size for the long-wall system is 84 inches. A comparison of the major cost components for each mine is set out in Table 13.

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*This appears to be the minimum rate of return accepted by the industry. See, for example, "1975-85 Coal Industry's Capital Requirements," John Frawley, Mining Engineering May 1975.

** U.S. Bureau of Mines, I.C. 8689 and 8682, Basic Estimated Capital Investment and Operating Cost for Underground Bituminous Coal Mines, 1975.

TABLE 13

1975 COMPARATIVE UNDERGROUND MINING COSTS
($/Ton)

Mine Type, Seam Size	Operating Costs	Capital Costs 2/	Cost Based Selling Price
Continuous, 48" Seam 1/	$8.50	$2.51	$14.83
Continuous, 72" Seam 1/	8.22	2.52	13.58
Long-wall, 84" Seam 1/	5.99	2.29	10.94

1/ Capacity equals 1 million tons per year.
2/ Excluding profit and taxes.
Source: Schedule III-E-8.

There are two parameters which influence costs shown in Table 13: seam thickness and technology. For a given capacity, increases in seam size, based on the model mine analysis, will lower the level of costs. This impact is amplified by employing a more productive technology such as long-wall mining. In addition, it is significant to note that the major impact of these parameters will be on operating costs rather than capital costs -- operating costs in Table 13 change by 42 percent while capital costs change by only 10 percent.

d) Surface Mining

The current cost structure for surface mining was also based on the Bureau of Mines model mines analysis.* Two surface mines with annual capacities of 6.7 million tons and 9.2 million tons were utilized as the basis for the cost projections. Although the original cost studies were developed in 1974, all costs have been adjusted to a 1975 basis, reflecting escalation computed from the relevant components of the BLS WPI and increases in wage scales and welfare fund payments based

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* U.S. Bureau of Mines I.C. 8661 Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, 1974.

upon the UMW wage contract of 1974.* In addition, two other adjustments were made to the base year costs. First, royalty payments were excluded from operating costs since they are computed on the selling price. Second, the DCF rate of return used in the initial studies was 12 percent. This was modified to a 15 percent DCF rate of return. The 1975 cost structure for the two surface mines are set out on Schedule III-E-9. Table 14 summarizes the major cost components for these mines.

TABLE 14

1975 COMPARATIVE SURFACE MINE COSTS
(Dollars Per Ton)

Mine Size (Million Tons)	Operating Cost	Capital Cost 1/	Cost Based Selling Price
6.7 T/yr., 6' Seam	$3.27	$1.38	$5.97
9.2 T/yr., 25' Seam	2.71	0.77	3.72

1/ Excludes profit and taxes.
Source: Schedule III-E-9.

Capital costs are more sensitive to changes in mine size and seam thickness than are operating costs -- operating cost changes by 21 percent while capital cost changes by 56 percent.

e) Costing Equations

The current costs developed for the various types of mines each reflect a certain set of mining conditions. If the coal reserves in each supply region were sufficiently large and homogeneous with respect to geologic occurrence, then it would be sufficient to merely take the cost structures presented above and adjust for real cost increases over the forecast period. For the most part, however, this is not true of coal reserves, especially the bituminous coal reserves in the Eastern supply region; thus, some

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* National Bituminous Coal Wage Agreement, effective December 6, 1974.

adjustment mechanism must be utilized to account for differences in mining conditions and also changes in technology.

Two factors are relevant here. First, for a given technology, certain mining costs will be relatively fixed with respect to changes in mining conditions while others will vary with such changes; yet, when major shifts in technology are considered, all costs can be considered variable over the long run. Second, that parameter most sensitive to changes in mining conditions and technology is productivity.

Given these considerations, the approach was to allocate total costs between those costs which are fixed and those costs which are variable with respect to productivity. The variable costs are then normalized with respect to the productivity implicit in the model mine cost studies. The resulting cost equations can then be adjusted for changes in productivity due to changes in mining conditions. Each equation, however, reflects the technology embodied in that particular model mine. Thus, complete shifts in technology must be handled through separate equations.

The determination of variable costs was based on an identification of all costs associated with the relevant unit of production for each mine type. All other costs were taken as fixed. For the underground mines, the variable costs included all relevant costs, both capital and operating, which were directly related to either the continuous mining section or long-wall section. The variable costs for surface mining included all costs directly associated with both overburden and coal removal. The resulting total cost equations not normalized for productivity are set out in Table 15.

TABLE 15

1975 COST EQUATION FOR MODEL MINES
(Dollars Per Ton)

Mine Type	Total Cost = Fixed Cost + Variable Cost
Underground, Continuous[1]	\$14.82 = \$7.54 + \$7.28
Underground, Continuous[2]	\$13.57 = \$7.00 + \$6.57
Underground, Long-wall	\$12.06 = \$7.42 + \$4.64
Surface, 6 MMT/yr.	\$ 5.97 = \$3.23 + \$2.74
Surface, 9 MMT/yr.	\$ 3.72 = \$2.46 + \$1.26

1/ 48" coal seam.
2/ 72" coal seam.

For the underground mines with continuous mining section, variable costs account for approximately 49 percent of total costs, while variable costs account for 38 percent of total costs for the long-wall underground mine. This results from the fact that the long-wall mines are less labor intensive with respect to the production units than are the mines employing continuous miners. For the surface mines, variable costs account for 46 percent of total costs for the six million ton per year mines. This difference is accounted for by the fact that the larger surface mine employs draglines for overburden removal.

The above equations were normalized for the productivity level implicit in the cost analysis for each mine. Table 16 sets out the productivity level for each mine measured in output per man-day. The procedure was to multiply the total annual variable cost by the productivity level for the appropriate mine. The resultant number can then be divided by the actual level of productivity determined for a particular region in order to derive the adjusted total cost for each type of mine.

TABLE 16

MODEL MINE PRODUCTIVITY
(Outputs/Man-day)

Mine Type	Productivity (OMD)
Underground, Continuous[1/]	18.35
Underground, Continuous[2/]	19.60
Underground, Long-wall	34.37
Surface, 6.7 MMT/yr.	154.84
Surface, 9.0 MMT/yr.	187.33

[1/] 48" coal seam.
[2/] 72" coal seam.

For example, if the productivity level were the same as that for the model mines in Table 16, the total cost would be the same. The costing equations to be utilized for the projections are set out in Table 17.

TABLE 17

MODEL MINE COST EQUATIONS ADJUSTED FOR PRODUCTIVITY

Mine Type	Total Cost = Fixed Cost + Variable Cost*/OMD**
Underground, Continuous[1/]	\$14.82 = \$7.54 + \$133.72/OMD**
Underground, Continuous[2/]	\$13.57 = \$7.00 + \$128.69/OMD**
Underground, Long-wall	\$12.06 = \$7.42 + \$159.60/OMD**
Surface, 6.7 MMT/yr.	\$ 5.97 = \$3.23 + \$424.50/OMD**
Surface, 9.0 MMT/yr.	\$ 3.72 = \$2.46 + \$235.99/OMD**

[1/] 48" coal seam.
[2/] 72" coal seam.

* Multiplied by OMD in Table 16.
** To be projected.

f) Projected Productivity

In order to project the regional coal costs, it was necessary to project productivity trends for the relevant types of mines in each of the producing regions. Through this parameter, it is possible to impart the effects of both mining conditions and technology on the total cost calculations. The projections of productivity were based on an examination of these two factors. It is to be noted that productivity in coal mining reflects a complex interaction of many factors and can be quite variable within any given coal field. Thus, the projections set out herein should be considered directional in nature.

A brief historical sketch of productivity trends for underground and surface mining is presented in Schedule III-E-10. A more recent trend (1964-1974) is shown for surface mining than for underground mining (1955-1974). In addition, the Mid-Continent has been subdivided into the Illinois Basin and Other Mid-Continent since the former has provided the majority of production from this region. It is well known that productivity in underground mining has been decreasing since 1969 when the Mine Health and Safety Act was passed. In addition, labor problems within the industry have also served to depress productivity. This also affected surface mining productivity which has not been directly affected by the Mine Health and Safety Act, but which has also shown declines since 1970 in both the Eastern region and the Illinois Basin area of the Mid-Continent region. The development of new surface mines in the Western region has served for the most part to keep productivity on the increase, although as shown in Schedule III-E-10, declines in productivity have also occurred in this region since 1972. One may speculate that perhaps state reclamation requirements and the effects of the freeze in Federal leasing have caused this decline.

Certainly, recent trends in productivity cannot be used directly as a gauge to project productivity over the 1985-2000 period since many of the factors creating the downturn must be considered short-run in nature and will in all probability be overcome by 1985. Thus, the projection of productivity must be made by examining the major influences over the forecast period.

As a first step in this examination, the effects of changes in the reserve base were analyzed. Based upon data compiled by the Bureau of Mines on average seam thickness for 5-year intervals covering the period 1950 to 1970, various statistical computations were made to test for a correlation between seam thickness and productivity. The results were not conclusive. This could be due to the fact that on an aggregate basis, such as was the case here, the change in seam thickness has not been that significant.

Schedule III-E-11 sets out bed thickness data on a national basis for all types of mining for 1950 and 1970. The schedule shows that over the 20-year interim, the distribution of coal production by seam thickness has not changed markedly. The most significant change appears to be the growth in production from coal seams less than three feet thick.

Sheet 2 of Schedule III-E-11 shows the average seam thickness of coal produced by underground and surface mining on a regional basis for the 1950 to 1970 period. The schedule shows that over this period there has not been a significant change in seam thickness in both underground and surface mining. Surface mining, however, exhibits more variability over time than underground mining, particularly in the West. In addition, the average seam thickness increases as one moves from East to West.

In summary then, on the basis of the regional data, and also given the fact that the reserve base over the forecast period will still be large, the net effect of changes in the reserve base on regional productivity is not considered to have a significant impact.

The other factor which could influence productivity is technology. In this area there appears to be a number of developments in underground mining which could significantly improve productivity. In order to place current mining technology into perspective, Schedule III-E-12 sets out the recent trend in underground production by mining method. The most significant feature in Schedule III-E-12 is the growth in continuous mining and the in-roads being made by long-wall mining techniques in the Eastern region.

A review of underground mining technology indicates that major increases in productivity could come through improvements in continuous mining technology through the use of automated mining systems and the application of continuous mines in short-wall mining systems. Presently, continuous miners are operating at approximately 11 percent of theoretical capacity; thus the potential for improvement is significant. With respect to the automated mining systems, the Bureau of Mines believes that capacity utilization of continuous mines could be increased to 63 percent of the theoretical maximum capacity.

In addition to improvements in continuous mining technology, the application of long-wall mining systems also could improve productivity. Presently, long-wall systems are producing on the average approximately 650 to 700 tons per shift, which is 60 to 70 percent higher than the average production from continuous mining sections. In 1974, there were 53 long-wall units in use producing 9.6 million tons of coal in the U.S. Additional shipments of equipment during 1975 should raise the number of units to 63.

Initially, long-wall mining was generally used where room-and-pillar methods were impractical and uneconomical. However, present installations in the major U.S. coal producing regions, ranging from thin, deep, friable coal beds to 10 feet thick, deep, highly faulted coal beds, give support to the belief that available-state-of-the-art long-wall equipment can be adapted to the broad spectrum of American coal seams and geological settings.

Other technological improvements including the removal of bottlenecks in transporting coal from the face, plus further refinement and modification of existing concepts, and equipment such as automated roof supports and bottling machines, should also serve to increase productivity in underground mining over the forecast period.

In surface mining, where productivity has historically been higher than in underground mining, there has been less of a need to improve productivity. This is especially true of the Western producing region where the major share of surface mine production will occur over the forecast period. It is assumed that existing technological methods will be utilized in surface mine production.

In light of the above considerations, it is apparent that in underground mining the potential for a resurgence of productivity is very likely. On the other hand, these technological developments may not be widely adopted and productivity may not increase as rapidly. With respect to surface mining, the influx of large scale surface mining should continue to influence the level of productivity, although a mitigating factor could be restrictive surface mine regulations which could serve to reduce the productivity.

Because of these countervailing factors, two productivity projections were made for the relevant type of mining in each supply region representing a high and low case. The projections are set out in Schedule III-E-13.

For underground mining, in both the high and low cases, it is assumed that by 1985 productivity will return to the level attained during the late sixties, prior to the inception of the Mine Health and Safety Act. Subsequent to 1985, the high case assumes a significant influence of technology change including heavy reliance on long-wall mining from 1990 onward. The high case assumes the 1985-2000 period would be similar to that period when continuous mining technology was embraced by the coal industry. Thus, the high productivity growth rate is based upon the highest rate attained in each region over the 1955 to 1969 period. The low case assumes a more or less normal influence of technological improvements with continuous mining providing the major share of production throughout the period. This projection is based upon the projections made in a study of manpower availability for the U.S. Bureau of Mines.*

Surface mine productivity projections are shown only for the Mid-Continent and Western regions since this type of capacity will contribute to incremental

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*<u>The Demand and Supply of Manpower in the Bituminous Coal Industry for the Years 1985-2000</u>, Pennsylvania State University September 1973.

supply in these areas. The high case assumes productivity gains will continue as large surface mines are developed. Thus the 1985 productivity level was based upon the rate of productivity growth for the 1964 to 1974 period. The low case assumes sporadic gains in productivity. Therefore, the highest level of productivity attained from 1964 to 1974 was assumed for 1985. From 1985 to 2000 the rate of productivity growth for both cases was based upon the rate of growth projected in the aforementioned manpower study.

The projected levels of productivity were utilized in the cost equations set out in Table 17 (infra) to determine the projected regional production costs. However, before this was done the costs were adjusted for real cost escalation over the forecast period. In addition, certain other cost adjustments were included.

g) Supplemental Adjustments to Basic Mine Costs

These adjustments include the cost of slopes for underground mines, preparation plant costs, severance taxes and royalties. Each are set out below.

1) Cost of Slopes

The Bureau of Mines model mine data are based upon drift mines and therefore do not take into account the cost of slopes for deep mines. In this study it is assumed that low sulfur coal will be produced from mines operating in depths of approximately 1,000 feet, while high sulfur mines are assumed to operate at an average depth of 500 feet. Thus it becomes necessary to adjust the total cost for the cost of slopes.* Based on discussions with Dravo Corporation, it was estimated that on an annualized basis, an adjustment

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* Slopes appear to be preferable to shafts in designing underground mines operating at depths of up to 1,000 feet.

of $1,200 per foot would be utilized to reflect variation in cost due to depth of operations.

2) Preparation Plant Costs

It was also necessary to adjust mine costs for the cost of coal preparation for bituminous low sulfur coals. These costs were based on a recent paper which presented comparative costs for both heavy media and a simple jig plant.* For the present analysis, it is assumed that heavy media cleaning would be utilized. Based on this paper, it was estimated that the 1975 cost per ton would be $3.03. This cost was projected to increase to $3.23 per ton in 1985 and $3.59 per ton by the year 2000, reflecting historical constant dollar increases in equipment and labor related costs. This estimate does not include the cost of coal lost in the washing process. Accordingly, the computed costs may be biased downward.

3) Severance Taxes

Schedule III-E-14 sets out the current severance taxes for each producing state. Based on Schedule III-E-14, plus data on average value per ton and production by state, an average severance tax rate was calculated for each supply region which was utilized to adjust the projected costs. The estimated rates are shown in Table 18.

TABLE 18

ESTIMATED REGIONAL SEVERANCE TAX RATES

Region	Tax Rates (Percent)
Eastern	2.4
Mid-Continent	-
Western	6.5

Source: Schedule III-E-14.

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*Economics of Coal Preparation, R.M. Quinlan and Stan Vankatesan, AIME paper presented February 1976.

It was assumed that these rates would remain constant over the forecast period.

4) Royalties

From Congressional hearings, it appears that the Department of Interior is proposing the establishment of royalties which will range between 5 and 10 percent of the value of the coal produced on Federal leases.* It is assumed that royalties will average approximately 7 percent for coal produced in the Western region.

5) Reclamation Costs

Based on the FEA National Energy Outlook report, it is assumed that reclamation costs for both Mid-Continent and Western coal will amount to 50 cents per ton over the forecast period.

6) Cost Escalation

For each of the relevant mine types, the 1975 operating costs were adjusted to reflect real cost increases over the forecast period. A review of capital cost escalation revealed that real cost increases were not significant, thus no major escalation was assumed. This escalation was based upon an analysis of constant dollar trends in wages, UMW welfare fund, and other major components of operating cost.

Over the forecast period, wage rates are projected to increase at a constant dollar rate of 3 percent while the UMW welfare fund is projected to increase at a rate of 7 percent per year. Other components of operating cost are projected

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* Federal Coal Leasing Amendments Act of 1975, Hearings, May 7, 8, 1975.

to increase in real dollars at a rate of approximately 1.0 percent per year.

h) Projected Mine Costs

Schedule III-E-15 sets out the projected costs for each supply region. The projected costs were developed by first escalating the cost components for each of the mine types relevant to each producing region. The cost equations were recalculated for each forecast year and adjusted for the projected productivity cases to derive the base total mine cost. The pertinent supplemental adjustments were then added to the base mine cost in each region to derive the FOB mine cost. In the Eastern region, these supplemental adjustments included slope costs, severance taxes, and preparation plant cost for the low sulfur bituminous coal. In the Mid-Continent regions, the supplemental adjustments included slope costs for bituminous coal and reclamation costs for lignite. The supplemental adjustments for the Western region included severance taxes, royalties, and reclamation costs for the lignite and subbituminous coal, while slope costs and preparation plant costs were added to the bituminous coal.

In general, the projections indicate a continuation of the regional cost patterns that presently exist. Over the forecast period, the projections show that Eastern low sulfur coal will be the highest cost coal supply, while lignite production in the Mid-Continent region will provide the lowest cost supply. Eastern high sulfur bituminous coals will be at higher cost levels than the high sulfur Mid-Continent.

The cost of subbituminous coal, a major source of low sulfur coal, is projected to increase toward the end of the forecast period to a level near that of the high sulfur Mid-Continent bituminous coal.

5. Consumer Coal Prices

The burner tip price for coal is that price relevant to a particular consuming sector. As such, the price includes the base FOB mine cost, plus transportation costs, plus adjustments reflecting the market influences of that sector as they relate to coal. Therefore, in this section, the recognition of these direct market influences transforms the cost projections into price projections. Interfuel market influences are not explicity taken into account here.

It is very difficult to quantify the price impact of direct market factors; thus, one must utilize adjustments which reflect cost of substitutes or cost differentials based on historic relationships. These types of adjustments are utilized herein. Burner tip prices are projected for the electric utility and industrial sector. With respect to the latter, a separate price projection is made for metallurgical coal in addition to steam coal.

a) Transportation Costs

Transportation costs are a significant portion of the burner tip price and will continue to be so over the forecast period. This factor will continue to contribute to the existence of a regional coal supply pattern. The prospective cost of transportation will reflect the cost of the predominant modal mix for each coal supply region. A review of the literature suggests that rail and water transportation will continue to be the dominant form of coal transportation, while the emergence of slurry pipelines could also make a significant contribution to transportation capacity. It is assumed in this study that all proposed slurry pipeline systems will be built. Schedule III-E-16 sets out data pertaining to both existing and proposed slurry pipelines. All of the proposed lines would be built in the Western U.S. Thus, it is assumed that this mode of transportation will have its primary impact in the Western coal supply region, while the major conventional types of transportation -- rail and water -- will continue to dominate the Eastern and Mid-Continent coal supply regions.

It is assumed that the capacity of the major transportation systems will be of sufficient size to handle projected supply. This assumption appears supportable based upon evidence submitted before Congress.* Under one study conducted for FEA and presented at the Congressional hearings, it was concluded that even assuming the FEA high scenario coal production case of 982 million tons, sufficient rail capacity would be available. The most likely area for some type of capacity constraint to occur would be water transportation. Based upon a study by the National Academy of Engineers (NAE) cited in the Congressional investigations, it was estimated that by 1985 approximately 330 million tons of coal could be transported on existing waterways. This estimate was based on a production target of 1.2 billion tons of coal by 1985. This projected increase in water-borne transportation is substantial when one considers that approximately 68 million tons of coal were transported by waterborne courier during 1974.** The NAE study concluded that such a significant increase in waterborne traffic would incur significant costs, which could result in the imposition of some type of user charge for water carriers.

The projected levels of production in the present study are much lower than those utilized in the NAE study; thus, it is assumed that while water transportation will

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*Coal Slurry Pipeline Legislation, Hearings Before Committee on Interior and Insular Affairs, House of Representatives.

**U.S. Bureau of Mines.

increase its share of the total transportation burden, the increase would not be sufficiently large enough to create a capacity constraint.

Projected transportation costs were based upon an examination of current tariffs and cost studies undertaken by different groups. The scope of the study did not permit a detailed examination of all elements which could affect transportation costs; thus it was necessary to rely on general measures of transportation costs. There are many uncertainties attending a projection of transportation costs. Salient among these are the impact of regulation on transportation costs, the impact of Government subsidies to the eastern railroads, and the potential for the imposition of user charges on waterborne carriers. In addition, there is the ever present question concerning the level of costs in the future and the extent to which these costs would be offset by increased productivity. This is particularly relevant to the railroads. The projected costs for each of the major transportation modes is set out below.

1) Slurry Pipelines

The slurry pipeline cost projection was based on the cost of a 1,000-mile, 25 million ton per year line. Based upon the evidence presented in Congressional hearings on slurry pipelines, it was estimated that the cost of transportation by slurry pipeline would be approximately 0.69 cents per ton mile. This was adjusted to reflect increases in the operating cost components over the entire forecast period and a one time adjustment for capital related costs, which assumes the pipelines would be in operation by 1985. The projection assumes that pipelines will not be required to recycle slurry water. An alternate assumption would serve to increase costs significantly. Table 19 sets out the projected unit transportation costs for slurry pipelines.

TABLE 19

PROJECTED SLURRY PIPELINE COSTS[1/]
(1975 Dollars)

Year	¢/Ton-Mile
1985	.91
1990	.93
1995	.95
2000	.97

[1/] 1,000-mile line with annual capacity of 25 million tons/year.

2) Railroads

The projection of rail line costs assumes that all utility coal shipped by rail will be transported by unit train, while transportation for the industrial sector will occur under multiple car shipments. There have been several cost studies of unit train movements, based upon a 1,000-mile 25 million ton per year movement, which have been compared to slurry pipeline costs.* The studies show costs ranging from 0.3 cents per ton mile up to 0.9 cents per ton mile. These estimates are not based on a regulatory framework. For the purposes of this projection, it is assumed that railroads would continue to be regulated over the forecast period although the regulatory bodies would make some provision for inter-modal competition. Therefore, the projections are keyed to existing tariff structure.

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*Coal Slurry Pipeline Legislation, Hearings Before the House Committee on Interior and Insular Affairs, 1975.

The base year costs for unit trains and multiple car shipments were based upon an examination of tariff data presented in a recent ICC hearing.* The tariffs were adjusted to a 1975 basis, from which an average unit cost factor was computed. This was approximately 1.0 cents per ton mile for unit trains and 2.0 cents per ton mile for multiple car shipments. For the projection period, it was assumed that the eastern rail lines would continue to increase their tariffs in line with costs, which were developed from an examination of the American Association of Railroad cost indexes. This assumption is probably conservative. In the United States Railway Association (USRA) study of the reorganization of the Penn Central System, it was indicated that significant opportunities existed for increasing coal rates based upon coal's value relative to other fuels and the relationship between average coal value and transportation rate.** In the Western U.S., it is assumed that a different type of pricing strategy will emerge. Here it is assumed that the railroads will compete with the slurry pipelines; therefore, the projections are based upon tariff escalation equivalent to that projected for slurry pipelines. The projections for unit rail costs are set out in Table 20.

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*ICC <u>Ex</u> <u>Parte</u> No. 270 Investigation of Railroad Freight Rate Structure-Coal, 1974.

**USRA, Final System Plan, Volume I, Part I, Section 7, July 26, 1975.

TABLE 20
PROJECTED UNIT RAIL COSTS
(1975 Dollars)
(¢/Ton Mile)

	1985	1990	1995	2000
East				
Unit Train	1.5	1.6	1.7	1.8
Multiple Car	3.0	3.2	3.4	3.6
West				
Unit Train	1.0	1.02	1.04	1.06
Multiple Car	2.0	2.04	2.08	2.12

3) Water Carriers

Very little data exist with respect to the cost of water transportation since coal is considered a bulk commodity, and therefore the rates are not specifically regulated by the ICC. Based on previous research with respect to transportation costs, it appeared that barge rates were approximately one-half of the unit train rates. This relationship is assumed over the forecast period. The eastern unit train costs were used as the basis of calculation. Table 21 sets out the unit costs for water transportation.

TABLE 21
PROJECTED UNIT WATER CARRIER COSTS
(1975 Dollars)

Year	¢/Ton Mile
1985	.75
1990	.80
1995	.85
2000	.90

b) Projected Burner Tip Prices in the Electric Utility Sector

The projected burner tip prices for electric utilities were developed using Census Regions as the consuming centers. Rather than present one price, assumed to be representative of a particular region, prices were computed for two distinct areas in each Census Region. Within each region, burner tip coal prices were estimated for geographic locations near water and inland. Using this approach, diverse regional burner tip prices were developed, facilitating comparisons with the other fuels and injecting more realism into the analysis.

Electric utilities will continue to provide the largest market for coal over the forecast period, and the estimation of burner tip prices is influenced by direct demand factors. The calculation of the projected burner tip prices also includes consideration of several other factors relevant to coal consumption by electric utilities. First, it was assumed that a differentiated steam coal product market would exist with respect to sulfur content. The market would reflect this through a price premium for coal which could comply with sulfur restrictions. This premium is assumed to be equivalent to the cost of stack gas scrubbing. Based upon cost data developed for Environmental Protection Agency (EPA), it was estimated that the cost of scrubbing would be 40 cents per million Btu.* This estimate was used as the premium for low sulfur coal and added to the projected FOB mine cost

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*Based on data shown in the report by PEDCo Environmental, Inc., "Fuel Gas Desulfurization Process Cost Assessment," May 1975.

for low sulfur coal throughout the forecast period.* A projection of prices for high and low sulfur coal in each census region was then possible.

Before regional prices could be determined, however, it was necessary to determine which coal supply region would provide the primary source of supply to a utility demand location. This determination was based in part on consideration of historical demand/supply patterns and also on a comparison of delivered costs for potential competing sources of coal supply. The transportation cost projections set out previously were utilized in developing the delivered costs. These projections were adjusted by a distance factor to derive the total transportation cost. In some cases, alternative transportation modes were analyzed in order to determine the lowest cost mode. The selection of the source(s) of supply was ultimately based on a lowest cost criterion where supply competition was apparent. This assumes, of course, that utilities will seek to minimize delivered cost in the selection of fuel supply. Schedule III-E-17 sets out the results of the analysis showing the projected burner tip prices for the utility sector. For each Census Region and forecast year, a burner tip price was derived using both the high and low FOB mine cost projection. Under each of these cases, a price for high and low sulfur coal was determined for each geographic location in a census region. Thus, a total of eight possible cases were developed for each region.

c) Projected Burner Tip Prices in the Industrial Sector

The industrial sector price projection includes an analysis of coal used for boiler fuel and metallurgical coal. Although metallurgical coal may also be used as

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*Admittedly this is a rather general assumption. In actuality the premium attributed to naturally occurring compliable coal would be determined at each power plant location depending upon the cost of scrubbing, the cost of the non-complying coal feedstock, and transportation.

a steam coal, the two products are, for the most part, separate entities with respect to the market influences on the burner tip price.* Therefore, each product is discussed separately.

1) Steam Coal

Burner tip prices are projected for large scale industrial users located at selected demand points in each Census Region as discussed in Chapter II. Industrial users of steam coal do not have the flexibility with respect to sources of supply that utilities have, due to smaller volumetric requirements which result in higher transportation costs. It was assumed therefore that industrial users would obtain coal from the closest coal supply region, although consideration was also given to historical supply/demand patterns where relevant. In addition, it was necessary to consider the transportation cost from alternative supply regions to the demand points. In some instances, this involved an analysis of alternate modes of transportation from a selected supply region. It was further assumed that throughout the forecast period industrial users would rely on conventional transportation modes; hence, slurry pipeline transportation was not analyzed. The final determination of the primary supply region was based on lowest cost criterion.

As with electric utilities, industrial consumers will also require low sulfur coal to meet environmental regulations. The industrial market will therefore attribute a premium to coal which is low enough in sulfur content to comply with the regulations without the need of stack gas

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*Burner tip price is a somewhat misleading term with respect to metallurgical coal since it is processed rather than burned. However, for the sake of simplicity, the term will be retained in the discussion. Its meaning should be taken as the price at the coke oven.

cleaning equipment. This premium is assumed to be equivalent to the cost of scrubbing which was added to the FOB projected mine cost for low sulfur coal. The cost estimate of 40 cents per million Btu used for the electric utility sector was also used for the industrial sector.* This estimate may be on the low side since industrial boilers may operate at lower load factors than utilities which would act to increase total costs. On the other hand, industrial boilers would probably be smaller than utility boilers, hence a smaller volume of exhaust gas would need to be desulfurized which would tend to lower scrubbing costs.

The results of the analysis are set out in Schedule III-E-18 which shows the projected burner tip prices for steam coal in the industrial sector. Four burner tip prices are shown for each demand point identified by a numbered metropolitan area. These prices include high and low sulfur coal under the cases of high and low mining costs.**

2) Metallurgical Coal

Metallurgical coal is a feedstock used to produce coke which is, in turn, used in the blast furnace with other raw materials to produce pig iron. Coke is used primarily for its chemical reducing properties, but also as a heat source in the blast furnace. As a feedstock, metallurgical coal must meet certain chemical and physical requirements which include low sulfur content, preferably below 1.3 percent, low ash content below 8.1 percent, low moisture and volatile matter, and high carbon content. Only certain

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*It is assumed here that large industrial consumers will be able to utilize stack gas cleaning technology similar to that used by electric utilities.

**Low sulfur coal is assumed to comply with the new source performance standards.

bituminous coals meet these requirements, hence supplies are limited and located in certain regions. Table 22 sets out the reserves of bituminous coal with the potential for metallurgical use by major coal supply region.

TABLE 22

RESERVE BASE OF BITUMINOUS COAL OF POTENTIAL METALLURGICAL QUALITY
(Million Tons)

Coal Supply Region	High Volatile Content	Medium Volatile Content	Low Volatile Content	Total
Eastern	11,899.6	2,964.9	3,098.2	17,962.7
Mid-Continent	113.6	41.5	33.8	188.9
Western	1,401.1	--	--	1,401.1
Total	13,414.3	3,006.5	3,132.0	19,552.7

Source: U.S. Bureau of Mines, Data Bank as of January 1974.

The Eastern coal region comprises almost 92 percent of total metallurgical grade coal while approximately 7 percent of the reserves occur in the Western region. The Mid-Continent region accounts for approximately one percent of the reserve base. In order to place the metallurgical reserve base in perspective, it should be noted that it comprises approximately 4.5 percent of the total U.S. coal reserve base. Since the majority of reserves are located in the Eastern and Western supply regions, these areas were assumed to be the source of supply for the price projections. The demand points were selected based upon an examination of data for coke production. Therefore, only seven of the metropolitan areas were used to compute burner tip for metallurgical coals.

The projection of metallurgical coal prices is comprised of the projected FOB mine cost plus preparation plant costs, which have been developed earlier in this section, an estimation of transportation cost from supply region to the point of consumption, and the addition of a premium reflecting market influences.

There are several factors which could affect the premium on metallurgical coal. As stated above, metallurgical must meet certain specifications. Reserves are limited, therefore, a scarcity value exists which causes metallurgical coal prices to be significantly higher than steam coal prices. This price disparity has apparently been recognized by steel producers who have sought to reduce the quantity of coke required to produce pig iron.

One measure of the utilization of coke in the blast furnace is the coke rate, which is the amount of coke consumed per ton of hot metal produced. From 1955 to 1974 the coke rate declined 31 percent from .881 tons of coke per ton of hot metal to .609 tons of coke per ton of hot metal.* The rate of decline has been accomplished primarily through more efficient blast furnace operation. This included such factors as (1) increased usage coupled with higher iron content of agglomerates and self-fluxing sinter, (2) higher blast temperatures, (3) use of high blast rates with pressure tops, and (4) increases in the injection of supplemental fuels.**

This latter factor is of interest. Supplemental fuel consumption includes primarily

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*American Iron and Steel Institute.

**U.S. Bureau of Mines IC 8677 - Impact of Changing Technology on the Demand for Metallurgical Coal and Coke Produced in United States to 1955, 1975.

residual fuel oil and natural gas, but also tar and pitch. From 1965 to 1974 consumption of supplemental fuels increased by 136 percent or at an annual average rate of approximately 10 percent.* The continuation of such a trend in supplemental fuel usage is questionable due to the significant increases in price of petroleum products since the 1973 Arab embargo and also due to the limited supplies and rising prices of natural gas.

In addition to the more efficient use of the blast furnace, steel producers are investigating various new processes such as formcoke, which would reduce significantly the amount of high quality metallurgical coal required to produce coke. A Bureau of Mines study indicated that the impact formcoke may have on the domestic metallurgical coal and coke market would depend on -- "(1) the economic and technical success of full-scale tests that are and will be conducted in the middle 1970's, (2) whether formcoke will be just a partial substitute or full replacement for metallurgical coke in blast furnaces, and (3) the rate of implementation by the domestic and foreign steel industries."** Finally, the development of metallurgical coal reserves in other parts of the world could also serve to increase supply. All of these factors would tend to reduce the scarcity value of metallurgical coal. In contrast, if no major supply augmenting developments were to occur while steel demand continues to increase, metallurgical coal would continue to command a significant premium.

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* U.S. Bureau of Mines.

** U.S. Bureau of Mines, IC 8677, p. 22.

An indication of the possible variation in the demand for metallurgical coal was provided in the previously cited Bureau of Mines report. The report indicated that assuming no change in technology, the total world requirements for metallurgical coal in 1985 would be 790.9 million tons; however, under conditions of changing technology, this requirement would be reduced to 725.1 million tons. The largest contribution to this reduction would be the implementation of the formcoke process which the report states, if fully adopted by foreign steel producers, would preclude to a large extent their imports of U.S. metallurgical coal.* This reduction in demand would probably continue to increase over the 1985 to 2000 period.

Since the demand for metallurgical coal is a derived demand, another indication of the potential requirements for metallurgical coal can be gained by examining the future consumption of iron. One such projection is provided in the EEI study under the three consumption scenarios.** Table 23 sets out the annual average rates of growth projected for iron consumption.

TABLE 23

PROJECTED GROWTH OF IRON CONSUMPTION[1/]
(Percent)

	1970-1985	1985-2000
Case A	3.2	2.8
Case B	3.0	2.2
Case C	2.5	0.4

1/No recycling.
Source: EEI, Economic Growth in the Future.

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*U.S. Bureau of Mines, IC 8677, p. 25, 1975.

**Edison Electric Institute, Economic Growth in the Future, 1975.

It is significant to note that under all three cases, production is projected to grow at a slower rate over the 1985 to 2000 period than the 1970 to 1985 period. This, in turn, implies a lower level of demand growth for metallurgical coal over the forecast period, although the absolute level of demand will continue to increase.

Based on the above considerations, two cases were developed for the computation of the metallurgical coal premium to be included in the burner tip price projection: a high case which assumes that in the face of rising demand, no major technological changes and no significant increases in high quality metallurgical coal reserves will occur; and a low case which assumes that there are continued technological improvements in steel making and that the technology for formcoke becomes commercially available on a large scale by 1985.

Under the high case, a premium equivalent to the current price differential between metallurgical coal and bituminous steam coal was utilized and added to the base FOB mine cost throughout the forecast period. This differential was estimated to be $35 per ton based on analysis by Bureau of Labor Statistics and other price data available from producers in the relevant supply areas. For the low case, it was assumed that the premium on metallurgical coal would decrease over the forecast period to a point where the price obtained for metallurgical coal would be equivalent to the price of low sulfur steam coal. This would appear reasonable since the low sulfur steam coal market would be the marginal market for a producer of metallurgical coal. In addition to the premium, a comparison of transportation modes and costs was performed in order to determine the lowest cost source of supply to each demand point.

The results of the analysis are shown in Schedule III-E-19. The schedule displays the projected burner tip prices for each of the aforementioned cases under the high and low FOB mine projections. Thus, four alternate price projections are shown for each demand point.

6. Range of Uncertainty in Projected Coal Prices

The qualitative discussion of uncertainties attending the projection of coal prices throughout this section should provide some indication of the care that must be taken in perceiving the numerical projections as precise measures.

There are a number of other uncertainties inherent in the burner tip price projections. First and probably the most significant uncertainty is the quantification of the premiums or discounts attributed to the price of coal in a particular market (supra). This, of course, embodies all the factors which determine the price of any commodity, the interaction of supply and demand, plus non-market factors such as political and environmental factors. Thus, at best, all any price projection can do is to indicate the possible levels toward which prices may tend, within the framework of assumptions embodied in the analysis. Second, transportation costs may vary significantly depending on the modal mix and the level of regulatory control. This factor will also affect the geographic distribution of supply. Third, the prices within a supply region could vary significantly, depending on both the geological and demand conditions faced by producers in any area of the supply region.

The uncertainties discussed indicate that the possible range of variation in coal prices is greater than the more probable prices shown under the various price cases developed above.

In order to provide some measure of this possible uncertainty, judgmental estimates of percent variations have been developed, as set out in Table 24.

TABLE 24

ESTIMATED RANGE OF VARIATIONS WITH RESPECT TO PROJECTED COAL PRICES
(Percent)

	1985	1990	1995	2000
Upward Variation	+100%	+100%	+115%	+150%
Downward Variation	-35%	-35%	-35%	-35%

These ranges should be viewed as an integral part of the price projection.

The estimate of the percentage variations was based on the following general considerations. First, it was concluded that factors affecting the upward movement of coal prices would probably be dominant and would embody the complex interactions of market and non-market factors. Second, the factors affecting the downward movement of coal prices would probably not be as dominant and would primarily reflect those factors affecting the cost of supply.

The translation of these assumptions into a qualitative judgmental estimation was derived on a percentage basis in the following manner. The upward movement in coal prices would, in the long run, be influenced by the price of world oil. Coal prices in the extreme case would rise toward the level of oil prices, although parity would not be attained due to the market valuation of differences in fuel characteristics. The upper range, therefore, was calculated by computing the percent difference between the medium projection of landed foreign oil prices and low sulfur eastern bituminous coal. This resultant percent was judgmental, adjusted downward to reflect the differences between the two fuels.

The downward percentage variation would reflect changes in the resource structure, technology, and other factors affecting the cost of production. In general these will be embodied in the productivity factor. While the high and low FOB mine projection was based on alternate productivity cases, it was deemed necessary to augment the adjustment which would, in turn, be reflected in the cost range. In order to estimate the possible range of variation, the error terms of regression equation which had been developed for the productivity analysis were examined. These indicated a deviation ranging from 30 to 40 percent of the mean estimate. Therefore, an estimate of 35 percent was assumed for the downward variation in cost. There was no basis to assume that the variation would increase or decrease over time; hence, it was held constant.

The resultant percentage range of variation as shown in Table 24, when applied to the projected price, should encompass the expected range of prospective coal prices. The range of variation is skewed upward reflecting the greater possibility of an upward movement of coal prices.

F. COAL-BASED SYNTHETIC FUELS

1. Introduction

The purpose of this section is to project the cost of coal-based synthetic fuels at the plant tailgate. The synthetic fuels include low Btu gas (less 200 Btu per cubic foot), high Btu gas (900 Btu per cubic foot or greater), and a synthetic liquid similar to crude oil.

Synthetic fuels in general and coal-based synthetic fuels in particular are considered by the U.S. Government to be an alternative to foreign oil imports. The development of these non-conventional sources of energy would also make greater use of the Nation's more abundant energy resources such as shale oil and coal. Of concern to the U.S. Government, however, is the time required for these sources of energy to become commercialized and their economic viability with respect to conventional sources of energy. In order to accelerate the development of synthetic fuels, the Energy Research and Development Administration (ERDA) has been established to provide Government support for research and development and demonstration. In addition, the President has proposed a National Synthetic Fuels Commercialization Program to provide Government incentives to stimulate investment in commercial scale synthetic energy plants, the outcome of which remains uncertain.

The development of commercial coal-based synthetic fuel plants is only in its initial stages. There are a number of plans presently under way to build commercial or demonstration plants, which are summarized in Schedule III-F-1. By 1985, the contribution to energy supply by coal-based synthetic fuels will be minimal, and the growth of coal-based synthetic fuels for the remainder of the forecast period will be strongly influenced by price, the availability of conventional energy forms, and Government policy.*

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*A study undertaken by the Synfuels Interagency Task Force concluded that -- "in the absence of Federal incentives, and changes in regulatory policy with regard to synthetic gas... significant amounts of synthetic fuels are not likely to be produced by 1985." Recommendation for a Synthetic Fuels Commercialization Program. Overview Report, Volume I, November 1975.

The approach for projecting the cost of coal-based synthetic fuels is based upon the prospective cost of production, which has been derived from the most recent publicly available data. Ideally, the projection should take into account the cost based upon the optimal technological mix over the forecast period; however, based on a review of the literature and discussions with ERDA personnel, it was concluded that at this time any analysis of optimal technological mixes would not be helpful. Thus, it is not the purpose of this section to identify or give the impression of identifying any specific conversion process as the best available technology, but rather to give an indication of how cost levels may be affected.

2. Low Btu Gas

The production technology of low Btu gas is developed and in use commercially.* Before the widespread availability of natural gas, low Btu or "town" gas was utilized. Presently, the attractiveness of low Btu gas lies in its application as a clean burning boiler fuel for electric power generation, especially combined cycle generation. The combination of these technologies, however, has not been fully demonstrated. In addition, low Btu gas could be used for industrial fuel application for either process heat or process steam. As shown on Schedule III-F-1, Sheet 3, there is only one low Btu gas demonstration plant project currently proposed in the U.S. by Commonwealth Edison and EPRI. The plant would produce 50 million cubic feet per day.

The projected cost of low Btu gas is based upon costs developed in the Synfuels Interagency Task Force Report (SITF)**. The basic cost components used by the SITF to estimate the price of low Btu gas were developed under alternate price calculations with and without the Government incentives. The major assumptions underlying these calculations are as follows:

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*There are approximately 45 plants operating in foreign countries utilizing the Lurgi, Winkler, and Koppers-Totzek processes.

**Overview Report, Ibid.

- Required price is based on a 15 percent discounted rate of return on debt and equity for the case without Government incentives and 20 percent discounted rate of return on equity only for the case with Government incentives.
- Costs are as of January 1975.
- Interest during construction is 10 percent.
- The plant capacity is assumed to be a 25,000 crude barrel equivalent per day.
- Cost of coal mine is not included.
- Land costs are not included.
- Plant life is assumed to be 20 years.
- Gas heating value is 127 Btu/SCF.

The result of the calculations for the unregulated case is shown on Schedule III-F-2, Sheet 1. With no Government incentives, the estimated price of low Btu gas as of January 1975 was estimated to be 410 cents per million Btu. The estimated price was reduced to 390 cents per million Btu when the recommended Government incentive was included in the price calculations. The incentives recommended by the SITF for unregulated low Btu gas included a 50 percent non recourse guaranteed loan and a price guarantee. The loan guarantee would facilitate capital acquisition and reduce the risk to the corporation, while the price guarantee substantially reduces market risk and assures the return on investment.

If it is assumed that low Btu gasification used for power generation would be subject to regulation, the January 1975 price estimated by SITF would be 270 cents without Government incentives and 227 cents per million Btu with Government incentives. The components of these estimated prices are shown on Sheet 2 of Schedule III-F-2. The major type of Government incentive for the regulated case recommended by the SITF was a 50 percent construction grant. This type of incentive was selected since it would directly provide capital, thereby reducing the problems utilities may have in raising capital for what may be considered a relatively risky project.

The lower cost under the regulated case stems from both the different capital structure which results in a lower overall return. While the regulated case results in a lower cost level, other factors may integrate this effect. These factors include the recent difficulties experienced by utilities in raising capital; the complications of regulatory framework when investing in new type process; and also the fact that this type of facility would require a different line of operational expertise. All of these factors could translate into higher rate levels for the consumer.

The projection of the low Btu gas price was developed for both the regulated and unregulated cases and is based upon the cost structures set out in Schedule III-F-2. Inherent in the projection is the assumption that plant related costs will, in general, exceed the rate of inflation. Thus, it is assumed that plant construction costs will exceed the general rate of inflation by 3 percentage points. In addition, the cost was adjusted to reflect increases in feedstock costs. The coal price projections developed in Section III-E were used to determine projected feedstock costs. Other operating and maintenance costs were assumed constant over the forecast period. Projected low Btu gas prices were developed for plants assumed to be located in each of the major coal supply regions. The price projections are set out on Schedule III-F-3.

The projections show that plants using bituminous coal produced in the East as feedstock will have the highest cost low Btu gas, while plants located in the Mid-Continent coal regions using lignite as feedstock would have the lowest cost gas. It is of interest to note that by the end of the forecast period the prices of low Btu gas produced in all regions tend to converge to the projected price of low Btu gas produced in the Eastern coal region. These relationships hold for both non-regulated cases and for those projections including Government incentives except that the level of the prices are lower. Government incentives would lower the projected cost in each region by 20 cents per million Btu under the non-regulated case, and by an average of 50 cents per million Btu over the forecast period under the regulated case. Finally, under the regulated case the projected prices would be approximately 140 cents per million Btu lower than the respective projected prices under the non-regulated case.

There are several major uncertainties inherent in these projections. Foremost among these is the technological mix to emerge over the period. This present projection assumes constant technology. Thus, improvements in the efficiency of the existing processes could affect the projections. The commercial application of some newer technology could also significantly affect the cost level. Most likely, these factors would tend to lower the prices of low Btu gas toward the end of the period. Another uncertainty is whether the Government will subsidize low Btu development at this time and, if so, would continue to subsidize low Btu gas development after 1985 when commercialization might be under way. The latter, of course, could depend on the prices and availability of other substitutable fuels. Finally, the environmental difficulty of siting a low Btu plant of commercial scale will affect the cost estimates.

Because low Btu gas is in a developmental stage, it is not possible to quantify these uncertainties, except to observe they could be substantial.

3. High Btu Gas

Synthetic natural gas or high Btu gas has probably received more interest in terms of commercial development than the other synthetic fuels, due to the need to replace the diminishing supplies of domestically produced natural gas.* Evidence of this is provided in Schedule III-F-1 which shows that 10 high Btu gas projects with a combined capacity of 4.4 billion cubic feet per day are presently planned or under consideration for development. Thus, the impetus to develop synthetic natural gas is readily apparent. The prospective supply of high Btu gas will be dependent upon the level of domestic natural gas supplies relative to demand, the volume of LNG that the U.S. Government permits to be imported, the price of alternative sources of energy, and the national energy policy. The latter two factors will be significant since they will determine the level of Government incentives, if any, required to assist in the commercialization of alternate processes.

In addition, since most high Btu gas plants would in all probability be built by either pipeline companies or gas distributors, the extent to which regulatory policy permits inclusion of such plants in the rate base will have an important effect on the supply and cost of high Btu gas.

At present, there is no commercial plant in the U.S. that produces high Btu gas which can be utilized in the existing natural gas pipeline networks, although the technology exists in the Lurgi methanation process. In addition to the Lurgi process, there are other gasifier units under development to produce high Btu gas. These are the Winkler and Kopper-Totzek processes. However, according to the SITF report, "only the Lurgi methanation process is sufficiently

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*High Btu gas has a heat content of 900 Btu/SCF or greater and is substitutable for domestic natural gas transported by pipelines.

proven to be used in the design and construction schedule needed to have commercial plants 'on stream' by 1985.[*] Indeed, practically all of the high Btu gas projects announced to date, as shown in Schedule III-F-1 would utilize the Lurgi process. The SITF report was careful to point out that "there is no exact industry knowledge of how difficult and costly methanation will be."[**]

Besides the aforementioned processes, there are a number of second generation processes under development. These include the HYGAS process, the CO_2 Acceptor process, the Synthane process, the Bi-Gas process, and the COGAS process. All of these processes have only been tested at the pilot plant level, thus considerable developmental work remains before the plants reach the commercialization stage. These processes, according to the SITF report, are expected to have higher thermal efficiencies and lower installation costs, which might serve to reduce the cost of commercially produced synthetic natural gas. Further, the SITF report indicated it was possible that some contribution to commercial supply could be made by 1985. Needless to say, the cost and operational experience for these second generation processes is even less defined than the processes closest to commercial development.

Based on the above, it is evident that a great deal of uncertainty exists with respect to both technology and cost. Since it is not known which process would be the most viable from a design point of view, one cannot project the technology mix over the forecast period. Further, there is no actual data to indicate how different plant sizes or production levels affect costs. In addition, the potential for modification in process units could also change both the level of

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[*] Synfuels Interagency Task Force, Recommendations for A Synthetic Fuels Commercialization Program, Vol. III, November 1975, p. I-87.

[**] Ibid, p. I-87.

costs and the status of the alternate technologies with respect to commercialization. These factors render any projection of costs extremely tentative in nature.

The projection of high Btu synthetic gas was based upon recent cost studies made by the U.S. Bureau of Mines Process Evaluation Group for the Energy Research and Development Administration. The studies were made for an assumed 250 MMcf per day plant size using first and second generation technologies. For the purposes of the projection, it was assumed that the Lurgi process would be prevalent in 1985, utilizing non-caking coals only. After 1985, it was assumed that while Lurgi would continue to be utilized for non-caking coals, one of the second generation processes would come "on stream" which could be utilized for caking type coals. The selection of this process was based on the criteria of lowest cost and ability to use caking coal. Table 1 sets out a comparison of the estimated tailgate costs for the different processes based on a 15 percent DCF rate of return.

TABLE 1

ESTIMATED PLANT TAILGATE COSTS FOR HIGH BTU GAS
(1975)

Process	Coal Type	Cost $/Mcf
Lurgi	Subbituminous	3.92
CO_2 Acceptor	"/Lignite	3.01/2.52
IGT HyGas	"/Bituminous	2.47/3.01
BCF Bi-Gas	"/Bituminous	2.71/2.69
Synthane	"/Bituminous	3.67/3.01

Source: U.S. Bureau of Mines, Process Evaluation Group Studies.

On the basis of the data presented in Table 1, the Bcf Bi-Gas process was selected as the prospective second generation process for which costs were projected. This selection is, of course, subject to the uncertainties discussed earlier. A comparison of the investment and operating cost components for the Lurgi and Bi-Gas process, along with comparative thermal efficiencies and coal feed rates, is shown on Schedule III-F-4.

The projected costs for high Btu gas were based upon the 1975 cost structure, which is adjusted for constant dollar escalation in coal feedstock, labor and plant costs. Table 2 sets out the major components of the estimated tailgate cost for 1975:

TABLE 2

COMPONENTS OF HIGH BTU SYNTHETIC GAS COSTS
(1975 Dollars)

Component	Lurgi Process		Bi-Gas Process	
	(¢/Mcf)	(percent)	(¢/Mcf)	(percent)
Direct Labor	4.0	1.0	3.5	1.2
Coal Feedstock	66.9	16.6 1/	94.2	32.0 2/
Operating & Maintenance	72.7	18.1	45.8	15.6
Depreciation	41.4	10.3	24.4	8.3
Taxes and Insurance	14.4	3.6	8.5	2.9
Profit	105.2	26.2	61.3	20.8
Federal Tax	97.1	24.2	56.5	19.2
Required Revenue	401.7	100.0	294.2	100.0

1/ Using subbituminous coal as feedstock.
2/ Using bituminous coal as feedstock.

Based upon the cost structure set out in Table 2, the direct labor cost component was escalated at annual average rates of 2 percent based upon an examination of constant dollar wage rate trends in the chemical and processing industries, while plant related costs were escalated at an annual average rate of 3 percent. Finally, the coal feedstock cost component was adjusted based upon the constant dollar coal projections developed in Section III-E. It was assumed that, environmentally, a gasification plant could be located in any of the coal supply regions; therefore, the feedstock tailgate costs reflect the regional differences in feedstock costs. The projected costs are set out in Schedule III-F-5. In

1985 projected tailgate costs are shown only for the Lurgi process using non-caking (lignite and subbituminous) coals.

After 1985 it is assumed that a "second generation" process capable of using both caking and non-caking coals would contribute to the commercial supply of high Btu gas. Thus, two projections are developed for the non-caking type coals over the 1990 to 2000 period.*

The projections assume no regulations and no Government incentives. In the SITF report the recommended economic incentive was a fixed percent non-resource loan.** This incentive according to the report would provide the regulated gas utilities with a mechanism for acquiring capital and reducing risk. Associated with the economics it was also recommended that high Btu gas plants be brought under FPC jurisdiction in order that the high Btu gas could be sold on a full cost-of-service basis. The recommended incentives did not alter the tailgate price estimated in the SITF report; however, the price in that report was based upon the assumption of plant regulation by the FPC.

The same degree of uncertainty in projecting prices is in attendance for high Btu gas as described above for low Btu gas.

4. Synthetic Crude Oil

Of the various techniques for converting coal into improved non-polluting energy sources, liquefaction processes may have several advantages over other synthetic fuels in terms of economics, confidence in commercial operability,

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*It is highly probable that by 1990 the Lurgi process will also be adaptable to caking type coals; however, no data were available which provided cost estimates of this process modification.

**Synfuels Interagency Task Force, Recommendations for A Synthetic Fuels Commercialization Program, Vol. III, November 1975, pp. I-18-20.

and the least time required to achieve commercial implementation.* The economic advantages are based on the fact that less chemical changes are required to convert solid coal into a liquid than to gases, and the liquefaction process energy-conversion efficiency is higher. Commercial liquefaction processes would utilize only well developed materials and equipment components already being used in existing commercial petroleum refineries. Since such equipment is already developed as off-the-shelf items, it follows that liquefaction plants could be put into operation more expeditiously than plants employing alternative processes requiring relatively uncommon conditions and materials.

While liquefaction has the potential to become a clean energy source in less time than other coal conversion products which have developmental problems, the impetus to develop such processes has not been as pronounced as that for gasification, for which a clearly defined market potential exists in terms of supplementing diminishing natural gas supplies. As shown on Sheet 3 of Schedule III-F-1, only one demonstration plant which would produce some 2,900 barrels per day of syncrude proposed by Coalcon has been announced to date.

At present, the only commercially available technology for liquefaction is the Fischer-Tropsch process. This process is used in the SASOL plant in South Africa. The plant is designed to produce a variety of liquid fuels from coal and has been operating since 1955. Due to the use of Lurgi gasifiers in this process, which requires a non-caking coal, Western coal would be the most acceptable feedstock.

Although no commercial-sized coal liquefaction plants are currently operating or being built in the United States,

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*Yavorsky, Paul M., "Overview of R&D on Coal Liquefaction." Paper presented at Second Annual Symposium on Coal Gasification, Liquefaction and Utilization at University of Pittsburgh, August 5-7, 1975, p. 1.

a number of processes are under serious investigation. Coal liquefaction processes identified in the SITF report as commercial contenders for a 1985 target date include the Solvent Refined Coal (SRC) process, the H-Coal process, the Hybrid process, and the Coalcon process.*

At the present all of the advanced technologies are in the developmental stage. Thus, major uncertainties exist in projecting costs for synthetic liquefaction. Cost data presently available are based on conceptual plants. The lack of operational experience precludes any judgments with respect to the effects of economies of scale and plant size on cost. The development of these advanced technologies to commercial scale could alter both plant design and relative ranking of the most promising technologies. Therefore, the projections which are developed herein must be considered only indicative in nature.

The Bureau of Mines Process Evaluation Group has recently completed for ERDA cost studies for three major liquefaction processes: H-Coal process, the SRC process, and the Synthoil process.** Each study was based upon a plant design producing approximately 50,000 barrels per day. Schedule III-F-6 sets out a comparison of both investment and operating costs for these processes. In addition, comparative data on thermal efficiencies and coal feed rates are also shown. Table 3 summarizes the total costs for each process.

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*Synfuels Interagency Task Force, Recommendations for A Synthetic Fuels Commercialization Program, Vol. III, November 1975, p. I-86.

**"Preliminary Economic Analysis of SRC Liquid Fuels Process Producing 50,000 Barrels Per Day of Liquid Fuels from Two Coal Seams: Wyodak and Illinois No. 6," prepared for ERDA, March 1976, ERDA 76-55.
"Economic Analysis of Synthoil Plant Producing 50,000 Barrels Per Day of Liquid Fuels from Two Coal Seams: Wyodak and Western Kentucky," prepared for ERDA, November 1975, ERDA 76-35.
"Preliminary Economic Analysis of H-Coal Process Producing 50,000 Barrels Per Day of Liquid Fuels from Two Coal Seams: Wyodak and Illinois," prepared for ERDA, March 1976,ERDA 76-56.

TABLE 3

ESTIMATED COSTS OF LIQUEFACTION PROCESSES
(1975 Dollars Per Barrel of Annual Capacity)

Cost Component	H-Coal	SRC Process	Synthoil
Investment	$46.40	$43.06	$40.08
Operating	$10.24	$ 9.65	$ 8.95

Source: Schedule III-F-6.

Overall the variation in costs among these processes does not appear to be significant since there is no more than a 15 percent variation in cost between the highest and lowest cost processes. In order to project the cost of liquefaction, it was necessary to select one of these processes. Based on a review of the SITF report, it appeared that the H-Coal process was the most advanced. Therefore, it was assumed that this process would reach commercialization earlier.* In addition, this process produces a product closest to what could be called a synthetic crude. This synthetic crude would have a sulfur content of 0.5 percent or less.

The projected cost of syncrude was based upon the H-Coal process cost developed by the Bureau of Mines Process Evaluation Group. The estimated cost structure, assuming a 15 percent DCF rate of return, is shown in Table 4.

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*It was assumed that the Fischer-Tropsch process, as suggested by the SITF, would not be the prevalent process over the 1985-2000 period.

TABLE 4

COMPONENTS OF SYNCRUDE COST BASED ON H-COAL PROCESS
(Assuming 15 Percent DCF Rate of Return)

(1975)

Component	\$/Bbl.	Percent
Direct Labor	\$.17	0.8%
Operating and Maintenance	4.23	19.2
Coal Feedstock[1]	4.29	19.4
Plant Depreciation	2.15	9.7
Taxes and Insurance	0.75	3.4
Net Profit	5.45	24.7
Federal Income	5.04	22.8
Required Price[2]	\$22.08	100.0%

1/ Assuming Subbituminous Feedstock.
2/ Assuming No Credits for By product Ammonia or Sulfur.

Based upon the cost structure shown in Table 4, projected costs were developed by adjusting for changes in feedstock cost based upon the coal projection determined in Section III-E. It was assumed that a liquefaction plant could be located in any of the coal supply regions. In addition, it is assumed that plant related costs would exceed the rate of inflation by 3 percentage points over the forecast period. Direct labor costs were adjusted to reflect a constant dollar rate of growth of 2 percent per year, based on an examination of wage rates in the chemical industry.

Schedule III-F-7 sets out the projected price of syncrude for plants located in each of the major coal supply regions. The projections show that while lignite and subbituminous coal-based plants have the lowest costs in 1975, over the forecast period plants utilizing bituminous coal would appear to have a cost advantage.

The projected prices are significantly higher than prices for conventional types of energy. The SITF study recommended that both a non-resource loan guarantee plus price supports would be necessary incentives to the commercial development of the liquefaction process.* The effect of the non-resource loan would be to reduce the SITF syncrude price estimate by 21 cents per million Btu. This differential was used to project the syncrude prices assuming Government incentives; and it is also set out in Schedule III-F-7.

As is the case in estimating the price of coal gas, there is a substantial range of uncertainty attending the price forecast for syncrude. At this time, this range of uncertainty cannot be estimated.

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*Synfuels Interagency Task Force, Recommendation for A Synthetic Fuels Commercialization Program, Vol. III, November 1975, p. I-39.

G. PROJECTED PRICES OF URANIUM ORE CONCENTRATE

1. Introduction

The range of uncertainty regarding future price levels is far greater for uranium than for conventional fossil fuels. There are numerous unanswered questions with respect to requirements, the size and nature of the resource base, and the costs of the various inputs in uranium exploration and production.

On the demand side, estimates of nuclear generating capacity and of uranium feed requirements vary widely, depending on the assumptions made with respect to growth in electric generating capacity and in nuclear power and with respect to nuclear fuel technology. Cumulative uranium requirements as estimated by the Energy Research and Development Administration (ERDA) under alternate assumptions, for the period to 2000, vary between 1,100 and 2,800 thousand tons.*

On the supply side, the experience with uranium exploration is very limited and the resource base is not well defined. Through 1975, cumulative reserve additions amounted to only 922 thousand tons, consisting of cumulative production of 282 thousand tons and reserves of 640 thousand tons of U_3O_8. Thus the total reserve additions through 1975 represent only a fraction of the requirements for new reserves between 1975 and 2000.

In light of the need for better information concerning the uranium resource base, the National Uranium Resource Evaluation (NURE) program was established in 1973 to evaluate and identify potentially favorable uranium areas throughout

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*Use of the EEI nuclear energy projections, in conjunction with the ERDA requirements figures, would change the feed requirements to approximately 775-2,110 thousand tons.

the United States. While a preliminary report has been published,[*] a comprehensive report of the NURE program is not scheduled until 1980.

Major uncertainties concerning uranium resources are the size of the resource base; the accessibility of uranium deposits, which will determine exploration costs; and the ore grades, ore depths, and ore thickness, which determine mine and mill capital requirements and operating costs.

Finally, there is only limited historical information available concerning expenditures for exploration, and virtually no detailed published historical data are available on expenditures for mine and mill construction and operating costs. In contrast, cost data have recently become available with respect to coal. For natural gas, price regulation by the Federal Power Commission has focused attention on the costs of finding, developing, and producing "new" gas-well gas, and the FPC cost studies have also yielded information relevant to the costing of new crude oil.

Given the wide range of uncertainty regarding uranium requirements and uranium resources, the price projections made here are order-of-magnitude approximations and the estimates must be regarded as less reliable than those made for the fossil fuels. The uncertainties are so great that they cannot be quantified.

2. Uranium Requirements and Supply

As specified by EPRI, price projections have been made within the framework of the electric energy forecasts made by EEI.

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[*] National Uranium Resource Evaluation, Preliminary Report, ERDA, Grand Junction, Colorado, June 1976.

The EEI projections for total electric generating capacity are shown in Schedule III-G-1 and the projections for nuclear capacity are shown in Schedule III-G-2 for 1980, 1985, and 2000. For comparison, the schedules also show the projections made by ERDA for the same dates. The ERDA projections of nuclear energy in 1985 are in close agreement with the EEI projections as of 1985, but for the remainder of the century the ERDA projections are much higher. By 2000, the ERDA "low" and "moderate low" cases span most of the range covered by the EEI nuclear energy forecasts and the ERDA "moderate high" and "high" projections are substantially higher than the highest of the EEI cases.

ERDA has prepared estimates of uranium requirements corresponding to each of its four projections of nuclear energy growth, and employing, for each growth scenario, several alternate assumptions with respect to uranium reprocessing, plutonium recycle, tails assay in enrichment plant operation, and introduction of the liquid metal fast breeder reactor (Schedule III-G-3). The variation in U_3O_8 requirements with differences in nuclear fuel technology is substantial. The highest cumulative requirements by 2000 for the "low" and "moderate low" nuclear capacity scenarios exceed the lowest requirement by about 60 percent. The highest requirements reflect the assumptions that: (1) the fast breeder reactor will not be introduced until after 2000; (2) there will be no plutonium recycle or uranium reprocessing prior to 2000; and (3) the tails assay will increase from the existing level of 0.20 percent to 0.30 percent. The lowest requirement level involves the assumptions that (1) the fast breeder reactor will come into commercial operation beginning in 1993; (2) plutonium recycle will start in 1983; and (3) the tails assay will remain at 0.20 percent.

The ERDA estimates of uranium requirements have been adapted to correspond approximately with the EEI projections of nuclear generating capacity. The estimates of cumulative requirements are shown in Table 1 below for each of the EEI energy projections.

TABLE 1

CUMULATIVE U_3O_8 REQUIREMENTS, 1976-2000

	Installed Nuclear Capacity (GWe)	U_3O_8 Requirements (000 Tons)
EEI Case A	740-890	1310-2110
Case B	602-720	1060-2060
Case C	437	775-1270

The range of requirements for uranium for the balance of the century thus varies from under 800 to about 2,100 thousand tons, depending on the rate of nuclear power growth and depending on developments with respect to nuclear fuel cycle. We have used this range of consumption requirements to estimate the quantity of new reserve additions which would be needed through the year 2000. The requirements for new reserves are shown in Table 2.

TABLE 2

REQUIRED ADDITIONS TO URANIUM RESERVES, 1975-2000
EEI NUCLEAR ENERGY PROJECTIONS

(Thousand Tons)

	Low	High
Cumulative consumption, 1976-2000	775	2110
Reserves, 1/1/76	(640)	(640)
Reserve requirements, 12/31/2000 1/	690	1890
Reserve additions required, 1976-2000	825	3360

1/ Reserves required at the end of 2000 are assumed as 10 times the requirements in the year 2000.

The wide range of potential reserve requirements is striking. While the alternative estimates of cumulative consumption vary by a factor of 2.7:1, the corresponding estimates of new reserves required vary by a factor of approximately 4.1:1. The extraordinary range in the estimates of prospective requirements for new uranium supplies underscores the difficulty of estimating future uranium prices.

Reserves as of January 1, 1976, together with estimates of potential uranium resources are shown in Table 3. The estimates include reserves and resources with a "forward cost" of up to $30 per pound. Schedule III-G-4 shows the data by cost increment. The low estimate of new reserve requirements -- 825 thousand tons -- amounts to about three-fourths of the potential resources believed to be in the "probable" category. However, at the high end of the range, new reserves required -- 3360 thousand tons -- exceed by 15 percent the total potential reserves now thought to be available, including those classified in the "probable," "possible," and "speculative" categories. The above comparison of reserve requirements and estimated resources does not take into account potential imports of uranium supplies.

TABLE 3

URANIUM RESERVES AND RESOURCES, JANUARY 1, 1976
TONS U_3O_8 WITH COST UP TO $30 PER POUND

Reserves	640,000
Resources - Probable	1,060,000
- Possible	1,270,000
- Speculative	590,000
Total Resources	2,920,000

Estimates of domestic reserves have been made by ERDA (formerly AEC) since the 1950's. The estimates are made for individual deposits based on engineering data made available by the uranium mining companies and are revised annually to make adjustments for production, inflation, and additional information on tonnage and ore characteristics.

The estimates of reserves and resources are made in relation to a maximum "forward" cost below which the ore is considered exploitable. The cut-off costs for the ERDA estimates include all future costs necessary to produce a particular body of ore, excluding, however, any return or taxes. Past expenditures, primarily for land acquisition and exploration, are excluded; hence, the estimates are frequently characterized as referring to "forward cost." The estimates of "forward cost" are made in current dollars and are based on costs at the time of each year's estimate.

Published estimates are available for discovered ore reserves and for three categories of potential resources -- probable, possible, and speculative. The reliability of the estimates decreases progressively from the reserves to the speculative resource class. Ore reserves are located primarily in the presently producing areas (the Colorado Plateau, Wyoming Basins and south Texas) and have been blocked out by drilling and other direct sampling. Conversely, resources are undiscovered and the estimates are made primarily by extrapolating data on known uranium deposits, or control areas, into areas having similar geologic characteristics. ERDA's definitions of the three classes of potential resources are shown in Schedule III-G-4.

Schedule III-G-4, showing ERDA's estimate of the uranium reserves and resources recoverable at forward costs of $10, $15, and $30 per pound of U_3O_8, illustrates several characteristics of the resource estimates:

a) About 42 percent of the reserves and of the probable potential resources are in the lowest cost category. Uranium prices were insufficient in the past to encourage exploratory drilling for higher cost supplies; therefore, only limited data were available to estimate resources in these highest-cost deposits. Analysis of exploratory drilling during the last several years, when uranium prices were substantially higher than previously, indicates that emphasis is on low grade material in known uranium districts. Because of the time required to compile and analyze drilling data, the reserve estimates lag 1-2 years behind drilling. It is believed that the recent drilling will result in increased reserves in the $15-$30 cost categories with no significant change in lower cost reserves.

b) Most potential resources are believed to be in areas that have been productive; therefore, the speculative class is small relative to total potential resources. As the cut-off cost is increased, a larger portion is in the speculative class; however, even in the $30 category, only one-fourth of the resources are in the "speculative" category.

c) At the higher cut-off costs, lower grade ores become economic and the lower grade ores constitute most of the additional tonnage at the higher costs.

Schedule III-G-5 shows the number of properties added at increasing forward costs for the reserves as estimated January 1, 1975. A substantial portion of the higher cost reserves are adjacent to or within areas of lower cost reserves. For example, over 40 percent of the additional reserves at $15 are located in properties also containing $10 reserves and 70 percent of the additional reserves at $30 are located in properties containing $10 and $15 reserves. In the past, some reserves have been lost by erosion as the mining operations have recovered the higher grade ores and bypassed the lower grade ores. Thus, whether all of the identified reserves are ultimately recovered depends to a large degree on whether producers are willing to mine the lower grade ore as they recover the higher grade ores.

While known mineralization is widespread, most of the reserves are in a relatively small number of deposits. As an illustration, 96 percent of the $30 reserves (January 1, 1975) are in only 239 of the 1,819 properties shown by ERDA.

3. The Approach to the Price and Cost Estimates

In deriving price projections for the forecast period, estimates have been prepared, at 5-year intervals, of anticipated costs on three alternative bases. The "low" cost estimate corresponds very roughly to the situation which might exist with low uranium requirements, combined with favorable discovery experience. The "high" cost estimate is applicable to the situation where uranium requirements are high (moderate growth, no fast breeder reactor or plutonium recycle, higher tails assay) and the resource base proves to be relatively unfavorable. The "medium" cost estimate can be considered relevant to a scenario of moderate uranium requirements plus a reasonably favorable resource base, or to certain combinations of requirements and resource base (for example, high requirements and a very favorable resource base).

The cost estimates which are relevant to the price projections are the anticipated costs in each year, as perceived by the sellers. The process of economic decision-making on the part of the mining industry is incompletely understood. However, as an economic matter, the costs which might be expected to influence the producers, as well as potential entrants into the producing industry, are the prospective costs and not the costs experienced in the past. The emphasis on prospective costs becomes particularly important where, as in uranium mining, increasing requirements press on a depleting resource base. For this reason, no attempt has been made to estimate the historical costs for the uranium ore concentrate which will be produced in each of the forecast years. Instead, the cost estimates attempt to show the costs which sellers may reasonably expect to incur for uranium produced as a result of exploration ventures which are initiated in each of the forecast years. In effect, an attempt has been made to project the costs as anticipated in each forecast year without any reference to past expenditures or commitments.

The costs shown for 1985 theoretically should represent the costs which would be incurred for new exploration ventures initiated in 1985. In view of the 8-10 year lead time between the initial steps in the exploration cycle and the 10-year production period, this would mean that the costs as estimated for 1985 apply to uranium which would be produced during the period 1990-2000. As a practical matter, however, it is not possible to pinpoint the precise years (and corresponding steps in the exploration-production cycle) to which the cost estimates refer. In light of the procedures used in preparing the cost estimates, the projection for any year, say 1985, should be considered to refer approximately to exploration activity undertaken over a period of years, e.g., 1983-1987, to mine and mill investment during 1987-1990, and to the related production for 1990-1999.

The format used in the cost estimates is a discounted cash flow (DCF) analysis. The simplified DCF procedure used by the Federal Power Commission in its costing of new gas-well gas in Opinion No. 770 has been adapted for the purpose of preparing the cost estimates.

The expenditures required to find and produce uranium are, traditionally, classified among: (1) exploration costs; (2) mine and mill investment; and (3) operating costs. In deriving the cost projections, we have estimated exploration costs from historical data compiled by ERDA and by its predecessor agency, AEC. For mine and mill investment and operating costs, historical data are not available and might not, in any event, be applicable to the lower ore grades to be processed in the future. The outlays are estimated by reference to our judgment of probable ore grade, in conjunction with published estimates of outlays required for various ore grades, ore tonnage rates, and by type of operation.

4. Estimates of Uranium Costs, 1985-2000

The estimates of uranium ore concentrate costs, inclusive of a DCF rate of return of 15 percent and income taxes, are shown in Table 4, below. The following discussion describes the procedures used in deriving the estimates of required outlays; the lead time employed; and the computation of costs, inclusive of taxes and return.

TABLE 4

PROJECTED COSTS OF URANIUM AT 15 PERCENT RETURN

(Dollars Per Pound U_3O_8)

1975 Dollars

	Low	Medium	High
1985	$31.50	$37.00	$59.50
1990	35.25	46.00	88.75
1995	40.00	58.00	135.00
2000	44.75	74.25	207.50

a) Exploration Costs

Exploration costs cover expenditures for surface drilling, including exploration and development holes; outlays for land acquisition; and "other" exploration costs, including geological and geophysical work and administrative costs. In preparing the cost projections, estimates were derived of the exploration expenditures per pound of U_3O_8 added to reserves.

Estimates of exploration costs have been made in two steps. First, exploration costs were estimated per foot of surface drilling. Next exploration cost per foot was divided by the "productivity of drilling" or the "discovery factor," i.e., the pounds of U_3O_8 added to reserves per foot of drilling. The result is an estimate of exploration cost per pound of U_3O_8 added to reserves.

Drilling costs per foot and total exploration costs per foot are shown in Table 5, below. The detailed AEC and ERDA information on drilling is shown in Schedule III-G-9 and on exploration expenditures in Schedule III-G-10. Schedule III-G-11 shows the exploration costs in relation to drilling footage for 1966-1975.

TABLE 5

DRILLING AND TOTAL EXPLORATION COSTS PER FOOT
1966-1975

	Drilling Cost Per Foot	Total Exploration Cost Per Foot
1966-1972	$1.25	$2.70
1973	1.49	2.91
1974	2.08	3.67
1975	2.90	4.80

Drilling costs per foot showed little change from 1966 to 1972, varying between $1.07 and $1.41 per foot, with an average cost of $1.25 per foot. After 1972, the drilling costs escalated sharply, increasing to $1.49 per foot in 1973, $2.08 for 1974, and $2.90 in 1975. In 1975, per-foot costs were two-and-a-half times as high as in 1972. Exploration costs other than drilling also escalated after 1974 though not so sharply as drilling costs. Land acquisitions and "other" exploration expenditures averaged $1.45 for each foot of drilling during 1966-1972, but increased thereafter to reach $1.90 per foot in 1975. Total exploration expenditures increased from $32.4 million in 1972 to $122.0 million in 1975 (an increase of 277 percent), while drilling footage increased from 15.4 million feet to 26 million feet (an increase of only 69 percent). Total exploration costs per foot of drilling rose from \$2.16 per foot in 1972 to \$2.91 for 1973, \$3.67 for 1974, and \$4.80 for 1975. The 1975 exploration expenditures of \$4.80 per foot of surface drilling were used as an anchor of the projections of exploration cost.

The second element entering into the cost projections is the productivity of drilling, or the discovery factor, i.e., the quantity of $U_3 0_8$ added per foot of surface drilling. Projection of the discovery rate for the future implies a judgment concerning the availability of uranium resources, their location and accessibility.

Historically, the data on $U_3 0_8$ reserves as estimated by the AEC and its successor agency, ERDA, were shown for reserves available at a "forward cost" of \$8 per pound. Over time, additional data have been published to show reserves available at a forward cost of \$10, \$15, and \$30 per pound, the information on \$30 reserves being available only for year-end 1973 and thereafter (Schedule III-G-6). Detailed information is not available for additions to reserves attributable to new discoveries, for upward or downward re-evaluation of the reserves estimates, or for shifts in the reported reserves from lower to higher cost categories resulting from inflationary cost increases.

The historical data provide a very imperfect basis for a projection of productivity of drilling for the future. Schedule III-G-12 shows the quantity of \$8 reserves added per foot of drilling and Schedule III-G-13 shows the annual reserve additions. It is evident that most of the \$8 reserves were found in two waves of discovery, one during 1955-1959 and one in the late '60's, so that there is very little sustained experience to provide a basis for a projection. Reserve additions per foot drilled have varied substantially from year to year, reflecting the good or bad discovery experience, but the long-term trend is clearly downward. Schedule III-G-12 also shows the drilling productivity on the assumption of a one-year lag between drilling and the reporting of reserves. On this basis, there is a continued decline in drilling productivity since 1967.

The data in Schedule III-G-12 indicate that as of 1974-1975, additions to $8 reserves per foot drilled had declined to the range of 1 to 1.5 pounds U_3O_8 per foot of drilling. Comparable estimates cannot be prepared for the higher cut-off costs because data are not available for a sufficient time span.

The sharp decline in $8 reserve additions per foot results, at least in part, from the escalation of the costs of mine and mill plant and operating costs. As the "forward costs" of producing a particular type of ore increase above $8, the reserve additions reported in this cost category obviously decline. What is not clear from the available data is the extent of change in the success of exploration in terms of physical availability of uranium resources.

In estimating future exploration costs, a 1975 base figure of $2.40 per pound of U_3O_8 reserves added was used, reflecting exploration costs of $4.80 per foot drilled and estimated reserves additions of 2 pounds of U_3O_8 per foot drilled. A recovery factor of 87.5 percent was assumed for 1985, resulting in exploration costs per pound of U_3O_8 recovered at $2.75.

The estimated distribution of the exploration costs is shown below:

Land acquisition	$0.38
Exploratory drilling	1.29
Development drilling	0.36
Other expenditures	0.72
	$2.75

Exploration cost was maintained at the $2.75 level for the entire period through the year 2000. Although it is reasonable to suppose that reserve additions per foot drilled may decline (in terms of the reserves above some cut-off ore grade), there appear to be certain offsets. At any particular time, the available reserve additions include different ore grades. Over time, lower grade ore bodies will become commercially acceptable even though the costs of producing such reserves are high. The lower the acceptable ore grade (i.e., the higher the acceptable production cost) the greater will be the economically recoverable reserve additions per foot of drilling. Therefore, a high uranium price and high producing costs may be associated with a relatively lower exploration expense per unit.

b) Mine and Mill Investment

Capital costs include mine and mill construction and mine and mill primary development. The projections of the outlays are based on estimates of the ore grade corresponding to each forecast year, used in conjunction with estimates of the investment costs for specified low grade uranium sources as shown in a 1974 study by AEC.*

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*An Estimate of the Economics of Uranium Concentrate Production from Low Grade Sources, John Klemenic, Assistant Director, Planning and Analysis Division, U.S. Atomic Energy Commission, Grand Junction Colorado, October 1974.

Schedule III-G-14 shows the change in capital outlays with ore grade, separately for open-pit and underground mining. In underground mining (assuming the processing of 5,000 tons of ore per day), the required capital outlays per pound of U_3O_8 increase from $2.54 for .10 percent ore to $3.93 for .05 percent ore, $7.29 for .025 percent ore, and $24.06 for .01 percent ore. For open-pit operations, the increase in required outlays with declining ore grade is particularly sharp, from $3.60 per pound U_3O_8 with .10 percent ore (at the 5,000-ton-per-day rate) to $57.16 per pound with ore containing .01 percent U_3O_8. The sharp rise in capital outlays with declining ore grade reflects, among other factors, the decline in percentage recovery with lower grade ores. The estimates of ore recovery used in the AEC study are as follows:

.10% U_3O_8	92.5%
.05	87.5
.025	77.5
.01	47.5

For any specified ore grade, the required capital outlays are also dependent upon the ore handling rate, on ore depth, and on ore thickness. The impact of these factors, however, is far smaller than the effect of ore grade. Costs also differ between underground and open-pit operations. Due to the insufficient knowledge about future reserve additions, it is assumed that 60 percent of production will be from underground mines and 40 percent from open-pit operations, based on the distribution of ore reserves as of January 1, 1975.

The assumption of future ore grade was guided by the data available for ore grade of existing reserves. As of January 1, 1975, the average ore grade for reserves producible at a forward cost of $10-$15 per pound was

.06 percent.* For January 1, 1976, the ore grade for reserves producible at a forward cost of \$15-\$30 per pound averaged .047 percent.** Schedule III-G-8 shows the distribution of total uranium reserves as of January 1, 1975 by ore grade. About two-thirds of all reserves were reported as being in ore grades of .02-.10 percent and 32 percent in ore grades of .02-.08 percent. Thus a significant proportion of existing U_3O_8 reserves are found in ores of .05 percent or less. It is reasonable to assume that supplies developed from 1985 exploration will approximate the lower band of ore grades of today's reserves.

In deriving the "medium" cost estimates, it was assumed that the ore resulting from 1985 exploration activities (which would be produced during 1990-2000) would approximate .05 percent contained U_3O_8; it was assumed for 2000 that the average ore grade would be .025 percent. The future reserves will be produced from supplies now classified as resources. Inasmuch as nearly 60 percent of the resources in the "probable" category are thought to be producible only at a forward cost between \$10-\$30 per pound and 40 percent at a forward cost of \$15-\$30, the estimate of .05 percent for reserves to be found in 1985 appears reasonable. The estimate for 2000 assumes a continuation of the decline in ore grades.

The "high" cost estimate assumes that, with greater uranium requirements or unfavorable exploration results, the applicable ore grade is .025 percent for 1985 and

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*ERDA, Statistical Data of the Uranium Industry, January 1, 1975, GJO-100 (75), pages 40, 46.

**ERDA Press Release No. 76-94, April 2, 1976.

.01 percent for 2000. The "low" cost estimates assume ore grade of approximately .075 percent in 1985 and .05 percent by 2000. The assumptions are summarized below:

	Assumed Ore Grade of Exploratory Activities		
	Low Costs	Medium Costs	High Costs
1985	.075%	.05%	.025%
2000	.05	.025	.01

The capital outlays used in making the cost estimates are shown in Table 6. The investments corresponding to each assumed ore grade were adapted from the Klemenic study, with the costs averaged over the range of tonnage-handling rates, and combined for open-pit and underground mining operations. The costs shown in the AEC study, which are at January 1974 price levels, were first restated in 1975 dollars. The costs were then escalated to 1985 and 2000 (10 percent every 5 years) to take account of the fact that mine and mill construction costs may be expected to increase more rapidly than the general price level. The projections for 1990 and 1995 were derived by assuming a constant-percentage increase in investment costs between 1985 and 2000. As a final step, the cost estimates were rounded.

TABLE 6

PROJECTED OUTLAYS FOR MINE AND MILL INVESTMENT
(Per Pound U_3O_8)

1975 Dollars

	Low	Medium	High
1985	$5.75	$ 7.25	$13.50
1990	6.75	9.75	21.50
1995	8.00	13.00	34.25
2000	9.25	17.50	54.25

c) Operating Costs

Operating costs include mining, hauling, and milling. The costs were projected on a basis consistent with the estimates of capital outlays, by reference to assumed ore grades. As was the case for investment costs, the "medium" estimates assume an average ore grade of .05 percent for the 1985 projections, declining to .025 percent for the projections applicable to the year 2000. The projections are shown in Table 7.

TABLE 7

PROJECTED OUTLAYS FOR MINE AND MILL OPERATING COSTS

(Per Pound U_3O_8)

	Low	Medium	High
1985	$ 8.50	$10.25	$17.50
1990	9.75	13.25	27.25
1995	11.50	17.25	42.50
2000	13.25	22.50	66.00

d) Lead Time

It was assumed that exploration activities begin 9 to 10 years prior to production, in accordance with estimates of lead time published by the Atomic Energy Commission and the National Petroleum Council. Inasmuch as precise data are not available for the timing of each item of exploration expenditures or mine and mill investments, a simplified schedule was adopted for the timing of exploration costs and investment costs. The lead time schedule is summarized in Table 8.

TABLE 8

ESTIMATED TIMING OF EXPLORATION AND INVESTMENT OUTLAYS

Year (Initial Production = 0)	Exploration	Mine and Mill Investment
-8	5%	
-7	20	
-6	25	
-5	30	
-4	15	
-3	5	10%
-2		25
-1		65

e) Total Costs, Including Taxes and Returns

Total costs, including income taxes and return were computed under each of the assumptions, using a DCF rate of return of 15 percent. The following assumptions enter into the computations:

1) An income tax rate of 48 percent.
2) Percentage depletion of 22 percent.
3) Expensing for tax purposes of 90 percent of exploration cost.
4) It is assumed that exploration costs are offset by tax benefits inasmuch as other taxable income is available to the producers.

In view of the uncertainties concerning the cost data, both royalty costs and the investment tax credit were ignored; these omissions tend to be offsetting.

The derivation of the estimates of costs under the "medium" assumption is shown in Schedules III-G-15 to III-G-18. Table 9 summarizes the components of the "medium" cost estimates for 1985 and 2000.

TABLE 9

COSTS PER POUND OF U_3O_8

1975 Dollars - Medium Estimate

	1985	2000
Exploration	$ 2.75	$ 2.75
Mine and mill investment	7.25	17.50
Operating costs	10.25	22.50
Total cash outlays	$20.25	$42.75
Return and Taxes	16.75	31.50
Total Costs	$37.00	$74.25

A rough check is available for the estimates of cash outlays, excluding taxes and return. For 1985, the "medium" estimate of cash outlays amounts to \$20.25 per pound of U_3O_8. For comparison, the average "forward cost" of the potential resources in the "probable" category may be estimated, using the ERDA estimates of resources by cost increment. The estimate of "forward cost" for the probable resources amounts to \$15.28, compared with the estimate of outlays of \$20.25. The difference between the estimates does not appear to be excessive, in light of the assumption that costs of uranium production will increase faster than the general price level. The check does not, of course, establish the correctness of the estimate of future outlays, but simply indicates that the outlay estimates are generally consistent with ERDA's judgment of forward costs.

It is more difficult to evaluate the reliability of the projections of total costs, including return and taxes, inasmuch as they are dependent on estimates of timing of expenditures and on tax computations, both of which are quite uncertain. An additional question arises concerning the use of the 15 percent DCF rate of return. The 15 percent figure was used because it has gained wide acceptance in DCF cost computations, but no studies were made which would indicate whether or not a 15 percent return is adequate to provide the incentive for the needed sustained expansion of uranium exploration and investment. It is evident that uranium production is a high risk business, not only because of the risks of exploration but also because of the uncertainties regarding the growth of nuclear power and uranium requirements. In view of the long lead time, producers undertaking new exploration ventures are faced with the risk that the supplies which are found may ultimately not be salable.

To indicate the cost range with alternative assumptions concerning return on investment, computations were made using a return of 20 percent, applied to the 1985 "medium" and "high" projections. The use of the 20 percent return changes the cost estimates as follows:

	15%	20%
1985 Medium	$37.00	$47.00
1985 High	59.50	74.25

f) Limitations of the Cost Estimates

As indicated, the cost projections are order-of-magnitude estimates and are subject to numerous uncertainties. The ore grades of future discoveries are not known and the estimated investment costs and operating costs for the lower-grade ores which are assumed to be processed in the future are not based on historical experience.

The reliability of the cost projections aside, it may be questionable whether cost estimates necessarily provide a close approximation of future prices in this industry. The rationale for the use of estimates of long-run costs is that these costs (for a specific quantity) provide a measure of the equilibrium price (for that quantity). Although it is recognized that prices for any product may exceed or fall short of the equilibrium level because of market factors, generally the prices are believed to be self-adjusting in the long term. If the price is above the long-term cost of production (including a return comparable with that available from alternative investments of equivalent risk), it is argued that the quantity supplied will tend to increase. New sellers will enter the industry and existing producers will increase their investment in the industry. Through this mechanism, it is thought that forces will be set in motion which will tend to move the price toward the equilibrium level.

Although prices for uranium ore concentrate will also tend to move to their equilibrium level over time, it appears that the adjustment process may be slower and weaker than for most industries and, consequently, that differences between price and cost may persist for some period of time. Alternatively, it is possible that prices may swing violently from levels above cost to below cost. The factors accounting for the weakness of the adjustment process include the long lead time between uranium exploration and production; uncertainties concerning the future growth of nuclear power and concerning the level of future uranium requirements; the role of sellers' anticipations of future price levels and of future costs; and the influence of price on cost incurrence.

The uncertainties with respect to future uranium requirements have apparently played a role in recent years in limiting the supply response of producers to price increases. Should these uncertainties remain unresolved, they might remain significant in the future. To illustrate, assuming that the price is above the long-term cost, new exploration may not be stimulated to the extent which might otherwise be expected if the sellers have questions regarding the viability of expanded exploration programs because of uncertainty whether the growth of nuclear power will be sustained, whether requirements will be reduced by introduction of plutonium recycle and whether, ultimately, the producing industry may not disappear with the fast breeder reactor.

An extremely important consideration is the fact that the price determines cost incurrence. With higher prices, it becomes feasible for producers to recover uranium ore concentrate from a broader range of low-grade ores. Thus, the price at any time influences the willingness to incur costs and the long-term costs will themselves be influenced by pricing history rather than the reverse.

Finally, it should be noted that the "long run" -- the period required for buyers and sellers to free themselves of past commitments -- is extremely long, particularly on the buying side because of the high capital cost of nuclear reactors and the lack of any substitute for uranium. Once a nuclear plant is built (or is so far committed that it is virtually certain to be built), it will create a demand for uranium feed for many years, almost without regard to price. Thus, the demand for uranium for existing nuclear plants is not price elastic (at least within enormously wide limits), and the expected reaction of buyers to price changes is considerably weakened. Of course, the price of uranium affects demand through its influence on nuclear fuel technology (adoption of uranium and plutonium recycling and determination of the tails assay used in the operation of enrichment plants), but considerations such as environmental policy and availability of uranium enrichment capacity are likely to be the more important factors affecting fuel technology.

Recent experience has demonstrated that forecasting uranium prices may be a precarious undertaking, even in the short term. Over a period of 25 years, the uncercertainties are, of course, magnified and the projections made here should not be regarded as predictions or forecasts of uranium prices.

5. Foreign Uranium Supplies

In projecting future uranium prices the impact, if any, of prices for foreign supplies has not yet been considered. Although foreign uranium for use in domestic reactors cannot presently be enriched in the AEC enrichment plants, this restriction is scheduled to be removed gradually beginning with 1977. The plan to lift the restriction permits up to 10 percent of the uranium delivered for enrichment by a domestic customer in 1977 to come from foreign sources, with increasing percentages of foreign feed permitted in subsequent years until the restrictions are completely lifted in 1984. Some modest commitments of foreign supplies to domestic buyers have already been made: as of January 1, 1975, approximately 40,000 tons of U_3O_8 had been committed for future delivery.

Estimates of foreign uranium resources (excluding Communist countries) are shown in Schedule III-G-19. "Reasonably assured" resources total approximately one million tons at a forward cost of $15 and 1.8 million at $30. Including the "estimated additional" resource category, 1.7 million tons are thought to be available at a forward cost of $15 and 2.8 million at a forward cost of $30. The identified resources are located in only a few countries, Canada, Australia, Sweden, and South and Southwest Africa accounting for a substantial part of the total.

Estimates of foreign requirements and production capability prepared by ERDA suggest that production capability from currently known resources will become inadequate by 1983 (Schedule III-G-20). The effect of a foreign supply shortage on the U. S. industry will largely depend on the development of additional supply from unexplored areas.

Additional supply from new deposits is probable inasmuch as large areas of the world are unexplored. However, there are a number of constraints and limitations. Much of the unexplored area is in less developed countries where financial resources, trained personnel, and technology are lacking. Political instability in some countries has restricted activities and government polices have, in some cases, restricted exploration and development. Finally, the lead time from initial exploration in new areas to initial production may be up to 15 years in developing countries.

An evaluation of world uranium resources in relation to requirements or of the cost of producing uranium in foreign countries is, of course, beyond the scope of this report. In any event, for the purpose of this study, the only relevant question is whether uranium imports will be available at prices below the prices for domestic supplies.

There is no reasonable basis to believe that there will be "cheap" foreign uranium. Beginning in 1972 and accelerating after the OPEC oil embargo, foreign governments adopted various policies restricting or impeding the development of sales to the United States. With the growth in nuclear power and increase in uranium requirements, both in the United States and abroad, and with the heightened concern regarding costs and security of energy supplies, it is highly unlikely that supplies from abroad will be available at prices below those charged by domestic producers.

Various press reports have referred to a "club" or "cartel" of foreign uranium producers. In mid-1975, it was reported that the U. S. Justice Department was investigating whether foreign individuals and corporations might be involved in violations of U. S. antitrust laws.[*] More recently, it has been reported in the press that the Department of Justice investigation has developed into a "wide-ranging hunt for a price-fixing conspiracy," and that subpoenas seeking documents and information have been issued to many U.S. producers.[**]

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[*] Washington Post, June 19, 1975.

[**] Wall Street Journal, July 7, 1976.

6. Uranium Prices, 1985-2000

The "medium" cost estimates, in 1975 dollars, amount to \$37 per pound in 1985 and \$46 per pound in 1990. As of mid-1976, spot prices for yellowcake were reported at \$40 per pound. While scheduled prices for future deliveries under long-term contracts negotiated in 1976 are not generally available, several press reports refer to prices in the \$40 range under recent long-term contracts. It is unlikely that uranium prices will decrease between the present time and 1985 in light of the high level of requirements relative to reserves and relative to available production capability. Although discovery of large new low-cost reserves could, of course, alter this price outlook, the most reasonable expectation at this time is for a continued rise in U_3O_8 prices. Consequently, in projecting nuclear fuel costs, the estimates for 1985 and 1990 have been modified. For 1985, the "medium" cost estimate was used at a 20 percent rate of return, namely \$47; for 1990, the price was interpolated between the \$47 figure and the cost estimate for 1995. Consequently, the "medium" price projections are as follows:

1985	\$47.00
1990	52.00
1995	58.00
2000	74.25

The price projections shown above refer to new sales of uranium supplies in each year for immediate delivery. Alternatively, the prices may be regarded as base prices for future delivery subject to escalation for inflationary cost increases. As of January 1, 1976, 138,000 tons of U_3O_8 were committed by uranium producers to domestic buyers under long-term contracts for future delivery, but only 12,000 tons of the forward commitments were for deliveries in 1985 or thereafter. Moreover, some purchasers have entered into procurement arrangements through advance payments to producers or through participation in production operations.

Increasingly, the price specified under the long-term contracts has been the market price in effect at time of delivery. Consequently, in deriving the estimates of nuclear fuel costs in the following section, the effect of averaging in the prices for deliveries under prior contracts was ignored.

7. Nuclear Fuel Cycle Costs

Projections of nuclear fuel generation costs are shown in Table 10. The costs are based on the U_3O_8 prices shown in the preceding section, together with the other cost components presented in Schedule III-G-20. The fuel generation costs were derived for a 1,000 Mwe light water reactor, incorporating the assumptions concerning plant operation and fuel carrying charges shown in the Appendix to Section IV-E.

TABLE 10

PROJECTED NUCLEAR FUEL CYCLE COMPONENT COSTS
(Mills/KWHR)

	Year				
Cost Item	1974	1985	1990	1995	2000
U Preparation	3.6868	8.7406	9.8212	11.1015	13.7411
Fabrication	0.7565	1.0473	1.2140	1.4074	1.6316
Shipping	0.0599	0.0828	0.0961	0.1113	0.1291
Pu Credit	(0.2112)	(0.2923)	(0.3389)	(0.3928)	(0.4555)
Total Cost	4.2920	9.5784	10.7924	12.2274	15.0463

CHAPTER IV

INTER-ENERGY PRICES PROJECTED FOR MAJOR CONSUMING SECTORS

A. INTRODUCTION

Chapter III developed and set out price and supply projections for major sources of energy for U.S. markets over the forecast period. These prices were projected primarily with respect to those factors affecting each fuel individually. In other words, interfuel relations and effects were not explicitly taken into account. The purpose of this chapter is to compare the individual fuel price projections in light of the total projected demand for energy, as provided in the EEI study, to adjust total demand to projected supply, and to directionally determine what effect these supply and demand relations would have on price. In this manner, the analysis serves to tie together the individual price projections by recognizing the aggregate effects of energy supply and demand. Moreover, since each end-use sector has its own set of unique market characteristics, it is necessary to examine sectorial consumption and price patterns. Here, the analysis indicates, on a directional basis, potential changes in sectorial price or consumption which might occur under an alternative set of demand conditions. These analyses will be presented for the four major energy consuming sectors: residential/commercial, industrial, electric utility, and transportation.

There are additional uncertainties which arise in this chapter, over and above those for the individual fuel projections set out in Chapter III.

There are uncertainties attending the retail price comparisons. A major uncertainty is the impact of interfuel price competition at the sectorial level. This impact will, of course, affect both the level of prices and the projected patterns of energy demand and supply. A quantitative investigation of these relationships is beyond the scope of this study.

Another major uncertainty is the extent to which non-price premiums and discounts will continue to play a role in the fuel selection and utilization process. This investigation is also beyond the scope of the study. However, it could especially affect demand patterns in the residential and commercial sector.

Finally, the expected increasing influence of electricity on consumption patterns and the impact of this influence on supply, demand, and price for other energy forms presents still another uncertainty. This consideration was not analyzed since the projected prices of electricity were specifically excluded from this study by EPRI.

B. ENERGY MARKET UNDER ALTERNATIVE DEMAND CASES

1. Introduction

Primary energy requirements of the U.S. to 2000 will be supplied from different sources -- coal, natural gas, petroleum, nuclear, and hydro. The supply of each energy type will come, variously, from domestic conventional production, synthetic production, and imports. This section deals with the projected level of U.S. demand by fuel and the corresponding sources of supply. The 1975 U.S. energy balance will be set out first, followed by an analysis of projected demands and supply for energy under alternative cases.

2. 1975 National Energy Balance

In 1975 the U.S. consumed approximately 71.1 quadrillion (Q.) Btu of primary energy, as shown on Schedule IV-B-1. Petroleum accounted for 46 percent of the total energy consumption, natural gas for 28 percent, coal for 19 percent, nuclear for 2 percent, and hydro for 4 percent.

Schedule IV-B-1 also sets out the U.S. consumption of energy by consuming sectors. The electric utility generation sector consumed 20.1 Q. Btu of energy in 1975, the largest quantity among the consuming sectors. Coal was the most important fuel consumed by electric utilities (44 percent); followed equally by natural gas, petroleum, and hydro power (15-16 percent); and nuclear (8 percent).

The transportation and industrial sectors followed the electric utility generating sector in the amount of energy consumed. Petroleum, primarily gasoline, was the predominant type of fuel consumed in the transportation sector. Natural gas was the major fuel consumed by the industrial sector, followed by petroleum and coal.

Lastly, the residential and commercial sectors consumed approximately 13.5 Q. Btu of energy in 1975. Here natural gas was the dominant primary energy source, followed by petroleum.

The supply sources of each energy type are presented at Sheet 2 of Schedule IV-B-1. The U.S. produced approximately 59.7 Q. Btu of energy in 1975, about 84 percent of domestic demand. Petroleum (crude oil and products) represented the bulk of imported energy, amounting to 12.3 Q. Btu. A small amount of natural gas was imported in 1975 (0.9 Q. Btu), primarily Canadian overland supplies. Only coal is currently exported from the U.S. (1.8 Q. Btu).

3. Projected National Energy Demand

One of the EPRI stipulations for this study was the use of the EEI demand forecast. EEI made three separate demand forecasts under different assumptions. The reader should refer to the EEI study for a full understanding of the different cases. In brief, Case A is the high growth case which assumes a vigorous public policy to support economic growth. Case B is the intermediate growth case which assumes a moderate reduction in the economic growth rate resulting from a lower population growth rate and a moderating public policy toward economic growth. This is considered by EEI to be the most likely case. Therefore, Case B is used as a base line or test case against which alternate supplies are compared. Finally, Case C is the low or non-growth case. A strong national commitment to a low growth society is assumed for this case.

The forecast of the total U.S. energy consumption for each case is set out in Table 1.

TABLE 1

TOTAL PRIMARY ENERGY CONSUMPTION
UNDER THE EEI DEMAND CASES
(Q. Btu)

	Case A	Case B	Case C
1975 (Actual)	71.1	71.1	71.1
1980	96.0	92.5	90.4
1985	115.9	106.9	101.2
2000	186.1	160.9	109.4

Schedule IV-B-2 sets out the EEI demand forecast by type of primary energy. There are sizable shifts over time in the proportion of fuels consumed. Set out in Table 2 are the percentages of fuels consumed for Case B, the base line case.

TABLE 2

DISTRIBUTION OF ENERGY
CONSUMPTION BY TYPE OF FUEL
EEI DEMAND CASE B

(Percent)

	1975 (Actual)	1985	2000
Coal	19%	16%	16%
Natural Gas	28	26	19
Petroleum	46	43	35
Nuclear & Hydro	7	15	30
Total	100%	100%	100%

While all energy types increase in absolute volume over time, nuclear and hydro (primarily nuclear) are projected to increase substantially faster than the other fuels. The nuclear and hydro market share increases from 7 percent in 1975 to 30 percent by 2000. Natural gas and petroleum lose the largest share, while coal's share decreases slightly.

4. Projected National Energy Supply

Future supplies of primary energy will come from three major sources: domestic production, synthetic production, and imports. Generally, it can be assumed that synthetics and imports will be supplying an increasing share of the oil and gas supplies, while domestic production of coal and nuclear will continue to supply demands.

Schedule IV-B-3 projects U.S. projected energy supply under the three EEI demand cases. The schedule estimates the level of supply from domestic production, synthetics, and imports. The supply levels are based on the projections for the individual energy sources as set out in Chapter III.

Domestic petroleum production includes oil, primary, secondary, and tertiary production, production of natural gas liquids, and shale oil. Both crude oil and products will continue to be imported. Natural gas imports include overland Canadian deliveries and LNG. Coal synthetics are limited to synthetic natural gas (SNG) at an assumed conversion efficiency factor of 61 percent.

Imports of petroleum are expected to double between the years 1975 and 2000, while imports of natural gas almost triple during this period. LNG will provide all of the increase in natural gas imports. Coal is expected to be produced in sufficient volumes to supply domestic requirements and the export market. Nuclear requirements for U_3O_8 should be met, although supply in part must come from some portion of what is presently classified as the resource base.

It is immediately apparent from the comparison of projected supply and the EEI demand projections that a potential imbalance exists with respect to natural gas. The excess gas demand will either be satisfied from unpredictable sources of natural gas or shifted to other fuels, or simply foregone. Of these three possibilities, the most probable would appear to be a shift to substitutable sources of energy. In order to gauge the impact of such a shift in supply, it is necessary to consider the sectorial demands for energy within the context of total requirements. In this way, it is possible first to determine what the probable allocation of gas supply would be among the sectors; second, to determine what alternate types of energy would substitute for any short-falls; and third, to determine what effect this would have on price. The analysis is conducted with respect to EEI Demand Case B since this represents the base case.

Schedule IV-B-4 sets out the energy supply-demand balance for 1985 and 2000, by sector, using EEI Case B demand. Two supply cases are shown for gas.* In deriving the balance it is assumed that high priority gas uses such as residential-commercial consumption, feedstock, and process heat would be

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*See Chapter III-D for description of the supply cases.

satisfied first, followed by lower priority boiler fuel uses. This procedure follows, in general, the current FPC policy for allocating gas supplies among the different sectors. Using this allocation system, Schedule IV-B-4 shows that no future gas supply deficiencies would occur in the residential-commercial sector but would occur in the industrial and electric utility sectors. The magnitude of these supply deficiencies under the high and low gas supply cases are shown in Table 3 below.

TABLE 3

GAS SUPPLY DEFICIENCIES UNDER EEI DEMAND CASE B
(Q Btu)

Sector	1985		2000	
	High	Low	High	Low
Residential-Commercial	-	-	-	-
Industrial	-	3.2	-	4.8
Electric Utility	5.1	5.3	6.4	6.8
Total	5.1	8.5	6.4	11.6

Source: Schedule IV-B-4

Under the high gas supply case a deficit is projected for the electric utility sector only, while under the low gas supply case a deficit is projected for both the industrial and power plant sectors over the forecast period.

Having determined those sectors where the potential for a gas supply deficiency is greatest, the analysis identifies possible alternative sources of energy required to supplement gas supply. In the industrial sector, it was assumed that the most likely alternative sources of energy to fulfill gas deficits would primarily be petroleum and, to a limited extent, additional synthetic gas and LNG. This assumption was based on the additional assumption that requirements for the industrial sectors would continue, in part, to tend toward the use of premium type fuels due to advantages with respect to handling, combustion, and processing applications.*

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*A basic assumption in this study, as set out in Chapter II, is that there would be no major restriction on petroleum imports.

To the extent the industrial requirements are for boiler fuel use, then domestic coal may fulfill the supply short-fall. In the electric utility sector it was assumed that the gas supply deficiency would be primarily made up by coal. This assumption was based on two considerations. First, utilities would seek to obtain the lowest cost source of fuel; and second, U.S. Government energy policy will continue to emphasize the use of coal for utility boiler fuel. It would appear that a shift to coal would be more probable than a shift to nuclear due to the greater flexibility in scheduling fossil plants. More importantly, the adequacy of the uranium resource base raises questions as to the availability and cost of meeting large increases in incremental demand.

Based on the above assumed shifts in consumption, it is possible to directionally indicate what the impact on price would be on a general basis. (A more detailed comparison of interfuel prices will be discussed on a sector by sector basis in Sections C through F below.)

Focusing on the low gas supply case, a substantial gas deficit was projected in the industrial sector. If the deficit were fulfilled by petroleum, it would probably result in an oil price slightly higher than the one developed in Chapter III-C. The reason being that at least part of the gas deficit could be made up by foreign oil imports which, under the assumed price control case, are projected above domestic oil prices.

If the natural gas deficiency in the industrial sector* is to be made up by imported oil, then the average petroleum product prices would be about one cent per MMBtu higher in 1985 and 2 cents per MMBtu higher by 2000.

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*1985 - 3.2 Q Btu or 1.5 MMBD.
2000 - 4.8 Q Btu or 2.3 MMBD.

It is conceivable that a portion of the gas deficit in the industrial sector could be supplied by additional imports of LNG and higher SNG production than were projected in Chapter III-D. If environmental, economic, and political restrictions were softened or eliminated, then the levels could be increased.

Set out below are the additional SNG and LNG supplies which would be required to fulfill the industrial market for the low gas supply case.

TABLE 4

SNG AND LNG SUPPLIES REQUIRED TO MEET INDUSTRIAL GAS DEFICIT

Q Btu

	1985	2000
Industrial Gas Deficit[1/]	3.2	4.8
Projected SNG Production in Chapter III-D	.8	2.2
Projected LNG Imports in Chapter III-D	.6	2.0
Subtotal	1.4	4.2
High SNG Production	2.1	4.0
High LNG Imports	2.5	5.0
Subtotal	4.6	9.0
Supply Increase	3.2	4.8

1/ Low gas supply case and EEI Demand Case B.

The above supply increase, if it occurred, would have an impact on the regulated gas price forecast developed in Chapter III-D. Directionally, the weighted average price of gas could increase by 21 cents per MMBtu in 1985 from the originally projected level of 149 cents per MMBtu* and by 16 cents per MMBtu in 2000 from the originally projected level of 270 cents per MMBtu.*

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*See Schedule III-D-2 in Chapter III-D.

Since the price impact of the supply alternatives was the smallest with respect to petroleum, it was assumed that the industrial gas deficit would be primarily made up by oil imports rather than increased supplies of LNG or SNG. Therefore, the adjusted oil prices are reflected in the sectorial analysis set forth in Sections C through F below.

In the electric utility sector the gas supply deficiency would increase coal requirements over the forecast period by approximately 30 percent under the low gas supply case.* While remaining recoverable coal reserves over the forecast period will still be sizable, it is probable that such an increase in requirements would evoke some type of price response, although the amount of such an increase is extremely difficult to gauge. Directionally, it is possible that the increased requirements would impose some pressures on the productive capacity of the industry. The net effect of these pressures would make the high case of the projected retail coal prices set out in Chapter III-E more likely to occur.

It is now possible to discuss and compare the projected burner tip prices, incorporating possible supply-demand modifications on a sector by sector basis. The purpose of this comparison will be to indicate directionally the dynamics of each particular market sector. As in this section, all analyses relating to projected demand are based on the EEI Demand Case B.

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*This would amount to approximately 200 million additional tons in 1985 and 340 million additional tons in 2000. To the extent that additional industrial boiler fuel requirements are met in part by coal, these incremental coal volumes would increase.

C. THE RESIDENTIAL/COMMERCIAL SECTOR

This section deals with the interface of fuels in the residential and commercial sectors (primarily for space-heating) and the directional effect this interface will have on the projected prices. However, a forecast of electricity prices was specifically excluded by EPRI from this study. Thus, a "real world" analysis of the residential and commercial market was not undertaken. Electricity is an important competitor in this market and is expected to become increasingly important.

The current supply/demand and price picture of oil and gas in the residential and commercial market is first set out.

Natural gas has typically been priced below the price of fuel oil at the burner tip in most parts of the U.S. The primary reason is the regulation of natural gas field prices. Only in the New England area has there recently been price competition between oil and gas in the heating market, caused by the high transportation and distribution cost of gas relative to other areas. In most other areas of the country, the price of oil in 1975 was approximately double the price of gas.

Set out in Table 1 below are the 1975 average regional prices for oil and gas in the residential and commercial sectors. These prices represent fuel costs for spaceheating use. The residential gas prices are average prices calculated from the local gas distributors' rate schedules. The volumes consumed were determined for each region according to seasonal degree days. The commercial gas prices represent a consumption level of 70 Mcf per month. The oil prices represent dealer tank wagon prices for No. 2 heating oil. The Census Region price represents an average of the cities within the Census Region which are set out in Schedule III-C-23 of Chapter III-C.

There is a considerable range of prices for the cities within each Census Region; therefore, these averages only represent the general price level for the region.

TABLE 1

1975 RESIDENTIAL AND COMMERCIAL PRICES
(¢/MMBtu)

	Residential		Commercial	
Census Region	Gas	Oil	Gas	Oil
New England	236	268	280	264
Middle Atlantic	158	274	169	270
South Atlantic	155	256	168	252
East South Central	103	244	110	240
East North Central	126	256	120	252
West North Central	107	251	100	247
West South Central	150	239	157	235
Mountain	98	266	98	262
Pacific	122	275	148	271

As might be expected, the regional energy consumption pattern reflects the relative prices shown for Table 1. Natural gas has captured the majority of the residential/commercial spaceheating market. Two sets of data verify this fact -- the 1973 distribution of residential heating installations set out on Schedule IV-C-1, and the 1974 consumption of natural gas and heating oil in the residential and commercial markets set out on Schedule IV-C-2.

In 1973 natural gas residential spaceheating customers represented 74 percent of total oil and gas spaceheating customers for the Nation. On a regional basis this percentage varied from 94 percent in the East South Central region to 26 percent in the New England region. The regional percentage variation conforms, in reasonable degree, to the price differential between oil and gas.

The regional consumption of oil and gas in the residential/commercial sector (Schedule IV-C-2) corresponds to the distribution of residential heating installations. For the Nation as a whole, 70 percent of oil and gas consumption was gas. The proportion of gas consumption ranged from 80 to 90 percent of the total in the East South Central, West North Central, West South Central, Mountain, and Pacific regions, while New England had the highest relative oil consumption.

Energy consumption in the residential/commercial market as projected in Case B of the EEI study will grow at an annual rate of approximately 2.6 percent. Over 70 percent of energy growth in this sector will be in electricity. Excluding electricity, over 80 percent of the fuel growth will be in oil. The results of our analysis support the high growth in oil compared with gas in the residential/commercial sectors. No analysis was undertaken to determine future electricity prices; therefore, no analysis and conclusion can be presented as to the high growth of electricity as projected by EEI.

Oil consumption in the residential/commercial sector is expected to grow at a faster pace than gas, primarily because a continuing gas shortage is expected to affect future gas availability for new markets, even in the residential/commercial sectors. Furthermore, gas prices are projected to increase much faster than oil prices. However, this factor may be offset by consumer preferences for gas compared with fuel oil for house heating.

Prospective gas supply has been discussed in Chapter III-D and sections of this chapter. It was found that on a national basis a gas shortage may be expected and that this shortage will probably extend into the industrial consuming sector. On a regional basis, this shortage may affect residential/commercial growth due to a gas distributor policy which restricts new sales. This situation has already occurred in many parts of the U.S. It is expected that gas distributors will be able to serve their existing markets; however, some may not be able to expand into new markets.

The forecasts of oil and gas prices in 1975 dollars were developed in Chapters III-C and III-D and modified in this chapter. These forecasts show gas prices rising substantially more than other fuels. Natural gas field prices have been regulated for many years, resulting in a price below market value. Gas prices are projected to approach market value in the future.

Schedules IV-C-3 and IV-C-4 recapitulated the oil and gas price forecasts at the burner tip in the residential and commercial sectors. These price forecasts were made essentially independent of interfuel competition.

The interface of fuels in the market place may well have an effect on prices. This is especially true in the free market scenario where prices are more flexible. Equal prices between fuels on a cents per MMBtu basis are, however, not to be expected. Many countervailing factors, some of which are listed below, would cause or maintain a price differential between competing fuels.

1. Regulation of Natural Gas

The field price and burner tip price of gas are generally regulated on the basis of cost and not market value.

2. Conversion Cost

The cost of conversion may be a major consideration in maintaining a price differential. The current conversion cost from a gas to an oil furnace in the residential sector ranges from approximately $1,000 to $1,200 (excluding interest foregone over the life of the equipment), or about 20 cents per MMBtu. Conversion from an oil furnace to a gas furnace would be somewhat lower.

3. Differences in Equipment, Operating, and Maintenance Costs

Generally, there is a higher cost associated with oil heating than gas. The initial outlay for an oil furnace (or boiler) and hot water heater is higher than for gas. Also, the operating and maintenance expenses for oil heating equipment are somewhat higher than for gas.

4. Combustion Efficiency

The combustion efficiency of gas furnaces historically has been greater than for oil furnaces. For furnaces currently in place it takes approximately 15 percent more Btu of oil input than gas to heat the same area. This situation is not expected to be as important in the future because new oil furnaces are reported to have the same efficiency as gas.

5. Versatility

Because of its versatility, gas may be preferred compared to oil since gas can be used for clothes drying and cooking.

6. Quality

Gas is considered a premium quality fuel relative to oil since it has practically no sulfur content and no odor.

7. Consumer Apathy

Consumers may not undertake to convert from one fuel to another even though a cost differential exists. Consumers may not know that a cost differential exists between competing fuels. Both factors would serve to maintain a price differential. These factors would tend to diminish as fuel costs account for a larger portion of the consumer's total expenditure.

8. Oil and gas may not be competing in the same market area.

The above factors indicate that gas and oil are not completely homogeneous fuels to be distinguished only by prices. On net balance one might expect gas to have a higher price than oil in a relatively free market. However, there is no historical experience to test this thesis because of gas regulation.

There are three Census Regions which have relatively large projected price differentials, as seen on Schedules IV-C-3 and IV-C-4. These are New England, West North Central, and Mountain. The remaining regions have smaller price differentials and therefore no major price adjustments can be made in this study to account for interfuel competition.

The largest projected price differential between oil and gas will be in New England. Gas prices are expected to be substantially higher than oil. Therefore, the growth in the residential and commercial sectors will probably occur in oil compared with gas. Oil prices may rise above the projected levels in response to supply and demand. Gas prices may have a tendency to fall below the projected level to the extent possible; e.g., higher priced supplemental gas may not be in demand.

The West North Central and Mountain regions also show a substantial projected price differential. Oil prices are projected to be substantially higher than gas prices. It is unlikely with this differential that oil would capture a large share of the heating market relative to gas unless oil prices were lower than the projected level. Gas prices will tend to increase above projected price levels, reacting to supply and demand in the free market case, while in the regulated price case, the market will demand a larger supply of higher priced supplemental gas.

D. THE INDUSTRIAL SECTOR

1. Energy Prices

This section presents a comparison of projected burner tip prices as they relate to the industrial sector, and discusses these prices in light of current and prospective energy consumption trends in the sector. The purpose here is to indicate directionally, based upon the price and consumption data, what changes may occur in this sector and how these compare to the demand projections made in the EEI study. The analysis will commence with a discussion of current prices and energy consumption in the sector and then proceed to the projections.

The industrial sector accounted for approximately 27 percent of the gross energy consumed in the U.S. during 1975, ranking this sector second to electric utilities in terms of sectorial energy consumption.* Table 1 shows the primary fuels consumed by the industrial sector in 1975.

TABLE 1

U.S. INDUSTRIAL ENERGY CONSUMPTION

Fuel	Volume (Q Btu)	Percent
Coal	4.2	22.3
Gas	9.0	47.9
Petroleum	5.6	29.8
	18.8	100.0

Source: Schedule IV-B-1.

On a national basis, gas was by far the predominant source of energy followed by petroleum and coal. The consumption of energy by stationary industrial users on a Census Region basis as of 1974 is set out in Schedule IV-D-1.** It should

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*It should be noted that 1975 was a recession year, which affected industrial output and, therefore, lowered energy consumption.

**1974 was the most recent year for which complete regional data were available.

be noted that the data totals set out in this schedule are not completely comparable to the data shown in Table 1, which includes fuel and non-fuel uses (e.g., metallurgical coal). Thus, the total shown in Table 1 is higher than that shown in Schedule IV-D-1.

The national predominance of gas shown in Table 1 is reflected for the most part on a regional basis. Gas has the major share of the industrial market in all regions except two -- New England and the Middle Atlantic. In these two regions residual fuel oil is the predominant type of energy used by the industrial sector. Coal does not predominate in any region relative to the other major fuels, although it ranks second to gas in the East North Central, East South Central, and the South Atlantic regions. LPG, which is shown for the sake of completeness, has only minor shares of the regional industrial market.

There are a number of factors which have contributed to the regional energy consumption pattern shown on Schedule IV-D-1. The industrial sector is most complex since the requirements and utilization of energy are widely divergent. Thus, it is very difficult to categorize the entire sector. Generally, however, it is possible to identify certain salient characteristics which affect industrial energy consumption. First, fuel cost must be considered since industrial users are, for the most part, large consumers of energy and therefore fuel cost contributes to a large portion of operating costs. Thus where possible, it must be assumed that the industrial user will seek to minimize the cost of energy. Second, process requirements will have an effect on the type of energy used. This factor may limit the types of fuel that can be used due to the manufacturing process involved. Third, fuel quality, rate of combustion and combustion efficiency will play a role in the selection of a fuel. These factors contribute indirectly to the cost of the fuel through capital and operating costs related to combustion and handling. The second and third considerations contribute to non-market premiums and discounts for a particular fuel. Fourth, the type of product produced may indirectly affect fuel selection since plant location relative to raw materials or the market may be dependent upon this factor.

When the above factors are considered with respect to the major fuels, gas has had the most desirable properties including a low price. Schedule IV-D-2 sets out regional prices for the major types of fuel as of 1975. These prices were determined on the basis of a relatively large industrial consumer. The gas price was based upon an average price for three levels of consumption: 5 MMcf per month, 15 MMcf per month, and 45 MMcf per month. Residual and distillate prices were based upon truck transport deliveries, while coal prices were based upon multiple rail-car shipments. The schedule shows gas prices to be substantially below fuel oil prices in all regions except the New England region where gas transportation and distribution costs add significantly to the burner tip price. It is interesting to note that in the New England region gas has the smallest share of the market due to both gas supply deficiencies and the relative prices of oil and gas.

Gas is also priced below coal in all regions except New England, although the differential in price between these two fuels is smaller than for fuel oil. Thus, the regional consumption data, discussed previously, lend support to the advantage of gas with respect to price and non-price factors as an industrial fuel.

The current energy structure in the industrial sector is, and will continue to be, in a state of flux due to several factors. The unilateral quantum increase in world oil prices initiated by OPEC in 1973 created an upward pressure on all other energy prices. These significant increases along with the embargo provided the impetus for energy conservation in the industrial sector as well as all other sectors of the economy. The conservation ethic continues to be an important factor in the industrial sector. The effect should be to reduce the level of energy growth in this sector as industry improves both combustion and process efficiency with respect to energy utilization. Another major factor contributing to the energy dynamics in the industrial sector has been the impact of the natural gas shortage. Since 1970 natural gas pipelines have increasingly curtailed supplies to large boiler fuel users in accordance with FPC directives. This, of course, includes the industrial sector, except where processing and feedstock requirements may rule out a feasible alternative source of energy. As discussed in Section B above, the gas supply situation will probably continue to grow in severity with respect to meeting the needs of both the industrial and electric utility sectors. This will foster the need to substitute alternative types of energy. As discussed in Section B, it was assumed that petroleum would replace most of the gas short-fall in the industrial sector, while coal would predominate in the electric utility sector, with consequent effects on the prospective price of petroleum and coal products.

Schedule IV-D-3 sets out a comparison of the projected burner tip prices on a Census Region basis for the major fuels which include coal, residual and distillate fuel oils, and gas. The most significant aspect of the data is the substantial increase in the price of gas relative to other fuels in all regions over the forecast period. Gas prices at the burner tip are projected to rise to the level of fuel oil prices by 1985 and to continue increasing to the year 2000. This, of course, reflects the contribution to supply of higher cost supplemental sources of gas such as SNG and LNG. In addition, domestic natural gas will increasingly cost more under both the free market and regulated price cases. The effect of the increase should serve to reinforce a shift to alternate fuels created by the natural gas supply deficiency.

Coal prices are projected at a level lower than both residual fuel oil and gas over the forecast period. However, the relative prices of coal and residual fuel oil, competitors in the industrial sector, are approximately the same as in 1975, with the major exception being New England and the East North Central region. Directionally, this implies that the prospective fuel consumption patterns in this sector, unadjusted for shifts due to the gas supply deficiencies, will remain essentially the same assuming no important restraints on importation of oil. Of course, on a regional level shifts in fuel consumption patterns will occur where the price differential for coal is large enough to offset the additional capital investments and operating costs incurred in using this fuel.

Assuming the above to be valid, it is of interest to examine the projected patterns of industrial energy consumption made by the Department of Interior and by the EEI. These are set out in Table 2 compared to actual data for 1974.

TABLE 2

COMPARISON OF PROJECTED PRIMARY ENERGY
CONSUMPTION PATTERNS IN THE INDUSTRIAL SECTOR
(Percent)

	1974	1985		2000	
	(Actual)	EEI 1/	Dept. Int. 2/	EEI 1/	Dept. Int. 2/
Coal	22.3	13.8	21.6	16.0	20.6
Petroleum	29.8	33.3	36.6	35.6	40.2
Gas	47.9	52.9	41.8	48.4	39.2
	100.0	100.0	100.0	100.0	100.0

1/ Demand Case B. Does not include metallurgical coal.
2/ *Energy Through the Year 2000*, Revised, U.S. Department of Interior. Includes metallurgical coal.

The inclusion of metallurgical coal in the EEI coal projections results in a somewhat lower share of total consumption than shown by the actual data and Department of

Interior projections. The projections, both EEI and Interior, show petroleum accounting for a larger share of fossil energy consumption. However, gas, as projected by EEI, maintains approximately the same market share in contrast to the Interior projection. Based on the analysis set forth in Section B of this chapter, the Interior projection appears more plausible on the basis of projected gas supply deficiencies. These results would be in agreement with the prices projected for the industrial sector.

The projected market share for coal may be understated in both studies. Based on the projected price levels, it would appear that directionally coal would maintain a larger share of the market than that projected by EEI or the Department of Interior. If coal were to increase its share of the industrial market, then it is probable to expect further upward pressure on coal prices above the levels projected.

2. Non-Energy Prices

The only non-energy related price projected for the industrial sector was metallurgical coal. A detailed discussion of the factors affecting both metallurgical coal demand and prices is set out in Chapter III-E. The purpose of this section is merely to set out the price projection adjusted to the price effects of the gas supply deficiency (supra). There it was stated that coal prices would tend toward the high end of the range projected. Taking this into account, then Schedule IV-D-4 sets out the projected metallurgical coal prices under the alternate technology cases.

E. THE ELECTRIC UTILITY SECTOR

The electric utility sector was the largest consumer of energy relative to the other end-use sectors during 1975. Given the significance of energy inputs to this sector, the effects of relative prices and availability will be important decision parameters affecting prospective patterns of energy utilization in the long run.

The purpose of this section is to evaluate the possible interaction in the market place of the different fuels and to determine directionally the impact on the price and demand projections. The current consumption volumes by fuel and by Census Region will first be set out. Then the current and projected fuel prices will be reviewed. Finally, the projected consumption volumes will be discussed in conjunction with the projected prices.

Schedule IV-E-1 sets out the regional consumption of energy by electric utilities as of 1974. Fossil fuels accounted for nearly 80 percent of all energy consumed by this sector, while nuclear and hydro accounted for 6.1 and 15.8 percent, respectively. The national dominance of fossil fuel consumption is reflected on a regional basis, with only the Pacific region showing a greater utilization of hydroelectric than any other type of energy.

Coal is the major source of fossil energy, while fuel oil and gas each comprise approximately the same proportion of consumption. On a regional basis, there is a diversity of consumption with respect to each of the fossil fuels, reflecting both cost and availability. For example, gas had a major share of the electric utility consumption in the West South Central region where historically it had been readily available at low prices. In contrast, fuel oil had the major share of the New England region where both gas and coal are not as readily available and are at higher price levels due to transportation costs. Coal has the predominant share of the remaining regional markets because it has been readily available and usually lower in relative price.

Nuclear based generation has a smaller but growing share of regional energy consumption by electric utilities. The East North Central region has the largest amount of nuclear utilization, followed by the South Atlantic and Middle Atlantic regions. Only the Mountain region has no nuclear generation at this time. Relative to fossil fuel consumption, nuclear utilization is most significant in the New England region followed by the Middle Atlantic and East North Central regions. Hydro based power generation displays a diverse regional pattern reflecting the availability of suitable water sites. The Pacific region has the largest share of hydro generation which far exceeds both nuclear and fossil fuel utilization. Of course, due to a limited number of remaining sites future growth in hydro generation will not be significant.

Schedule IV-E-2 sets out regional average fossil fuel prices for the electric utility sector for 1975. A substantial amount of diversity exists both among the types of fuels and among regions. Fuel oil prices are consistently higher than both coal and gas in all regions. The differential between fuel oil and the latter two fuels is substantial, averaging 124 cents per million Btu for coal and 108 cents per million Btu for gas. Coal prices are relatively close, although for the most part lower than natural gas. The lowest average coal price occurs in the Western regions, reflecting the fact that both production costs are lower and that power plants are closer to the source of supply reducing transportation costs. In the Eastern regions gas prices tend to be lower than coal prices, with the exception of the East Central regions.

When the current fossil fuel price structure is viewed in light of the consumption patterns discussed previously, it is not difficult to discern why coal provides the major share of fossil energy to the utility sector. The consumption pattern with respect to fuel oil is not as obvious when viewed solely on the basis of price; the reason being that the major shift to fuel oil was primarily undertaken by utilities on the East Coast before substantial world oil price increases occurred. In addition, air quality regulations have been most restrictive in the Eastern Seaboard States which has made the use of low sulfur fuels a requisite for meeting the regulations. Thus, factors other than price have contributed to the continued use of fuel oil. Gas, on the other hand, which has a price substantially lower than fuel oil, and is also an environmentally preferable fuel, does not have a larger share of the market due to supply limitations.

While it is clear from the above discussion that price alone is insufficient to completely determine the pattern of energy consumption, the significance of price in the decision making process, particularly in the long run, cannot be denied. Thus, a comparison of projected burner tip prices in the electric utility sector should provide some insight into the projection pattern of utility energy consumption. To this end, it is the projected burner tip prices of fossil fuels that are reviewed first, followed by a discussion of uranium prices. This sequence is necessary because a simple Btu price equivalent comparison of fossil and uranium price would not be accurate due to the nature of the nuclear fuel cycle. However, in order to provide some measure of comparison between the major fuel types (i.e., fossil vs. nuclear), a "breakeven" type of analysis was conducted with respect to nuclear fuel. This analysis takes into account all aspects of the nuclear fuel cycle and produces the U_3O_8 price which would be required to generate electricity at the equivalent cost of selected fossil fuels.

Schedule IV-E-3 sets out the projected constant dollar burner tip prices for the fossil fuels -- coal, residual fuel oil, and gas -- on a regional basis over the 1985 to

2000 period. Prices are shown for high and low sulfur coal, for low sulfur residual fuel, for both controlled and free market cases and for gas under both the free market and price control cases. Over the forecast period coal prices will remain at levels lower than both residual fuel oil and gas. Gas prices, however, will rise to the level of fuel oil prices throughout the forecast period under either of the two cases shown in Schedule IV-E-3. The substantial increase in gas prices reflects the impact of higher cost supplemental gas supplies and the higher cost of new gas (or replacement gas) as proven reserves are depleted. It should be noted here that projected gas prices are shown primarily for the sake of completeness. As discussed in Section B of this chapter, the limited availability of natural gas should substantially, if not entirely, eliminate consumption of this fuel by electric utilities over the forecast period. Therefore, the primary fossil fuels available to the utility sector will be residual fuel oil and coal.

There is no question that the price differential between residual fuel oil and coal will have an important bearing on the consumption of these fuels by utilities. However, other factors such as power plant location, environmental regulation, and other non-price factors will contribute to the continued use of residual fuel. Yet, it appears that coal will continue in its dominant role as a source of energy to the utility sector. The other major source of energy will be nuclear power.

The uranium price projections were developed in Chapter III-G. In that section, it was stressed that the range of uncertainty regarding uranium prices is much greater than for the fossil fuels for several reasons, including the limited amount of information pertaining to cost and the size and nature of the uranium resources. While other cost components of the nuclear fuel cycle were discussed in that chapter, the price projection of primary interest is that for uranium ore concentrate since this will determine future supply, and also will be one of the key parameters evaluated by the utility sector in the decision to install nuclear or fossil capacity. Table 1 sets out the projected $U_3 0_8$ prices.

TABLE 1

PROJECTED $U_3 0_8$ PRICES

Medium Case

Year	Price/($/lb.)
1985	$47.00
1990	52.00
1995	58.00
2000	74.25

Source: Chapter III-G.

The projected prices of $U_3 0_8$ are at levels higher than current long-term contract prices. This is in part due to the uncertainties attending the exploration, development, and processing of lower grade ores. These higher prices may affect the growth of nuclear power when viewed with respect to fossil fuel prices. Alternatively, assuming that there may be some interfuel price effects, the prospective prices of fossil fuels may influence $U_3 0_8$ prices and therefore prospective supply. In order to evaluate the fossil nuclear price interface, a "breakeven" type of analysis was undertaken. This analysis provides an alternate estimate of the future value of $U_3 0_8$ based upon the projected cost of fossil fuels. The breakeven methodology estimates that price of $U_3 0_8$ which would be required to generate electricity at a cost equivalent to that of comparable fossil fired plants. The power plant under consideration here is the incremental new base load plant which will supply electricity in each of the forecast years.

The breakeven analysis required the projection of both the capital and energy costs of a fossil plant and the capital costs of a nuclear power plant. These projections were developed using the Concept III computer program.*

This program simulates the construction and operation of both fossil-fired (i.e., coal, oil, or gas) and nuclear power plants, and thereby provides detailed cost estimates for plants of various sizes at varying locations as well as varying in service dates.

In addition to power plant costs, the breakeven analysis required an analysis of the projected costs of the nuclear fuel cycle. This analysis permitted the estimation of the breakeven U_3O_8 price based upon a computed energy cost. The nuclear fuel cycle analysis was developed using the GEM computer program.** The assumptions underlying the analysis are set out in an appendix to this section.

The major steps in the analysis are as follows:

1. Determine the future capital cost of the three types of plants by the use of the Concept III program.

2. Convert the capital costs to an equivalent annual cost per Kwh ($/Kwh).

3. De-escalate the capital cost to a 1975 basis.

4. Determine the energy cost (¢/Kwh) of U_3O_8 ($/lb.) varying from $5/lb. to $50/lb. in $5/lb. increments projected to the year 2000. This was accomplished through the use of the GEM Program.

5. De-escalate the U_3O_8 costs to a 1975 basis.

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*ORNL, CONCEPT: A Computer Code for Conceptual Cost Estimates of Steam Electric Power Plants, AEC Publication WASH-1180, April 1971.

**Hary, Daniel F. and Hughes, John A., Program GEM, General Economics Model to Analyze Nuclear Fuel Cycle Costs, University of Illinois, Urbana, Ill., Sept., 1973.

6. Convert coal and fuel oil costs from ¢/MMBtu to $/Kwh. The coal and fuel oil prices (costs) were taken from Chapter III of this report.

7. Determine U_3O_8 breakeven costs by:

a) Adding fuel oil and coal costs ($/Kwh) to their respective capital costs ($/Kwh) to derive a total cost for each to produce electricity and then subtracting from each the nuclear capital cost ($/Kwh). This establishes the equivalent nuclear energy cost ($/Kwh).

b) Determine the required U_3O_8 price to equal the fuel oil and coal cost of generating electricity by using the results of the GEM Program which converts the energy cost ($/Kwh) to a U_3O_8 price ($/lb.).

The results of the breakeven analysis are presented in Schedule IV-E-4. The breakeven "prices" are shown on a regional basis for low sulfur coal and low sulfur residual fuel oil. Low sulfur fuels were selected as the most relevant since the Concept program does not include stack gas cleaning costs. Although the breakeven "price" projection is shown for low sulfur fuel oil, the primary fuel interface will be between coal and nuclear.

Table 2 sets out the average of the regional breakeven "prices" estimated with respect to coal and oil. There is a substantial difference between the two fuels, reflecting primarily the difference in the projected price levels.

TABLE 2

PROJECTED U_3O_8 BREAKEVEN "PRICES"

U.S. Average
($/lb.)

Year	Estimated with Respect To: Low Sulfur Coal	Estimated with Respect To: Low Sulfur Fuel Oil
1985	$69	$152
1990	72	162
1995	80	188
2000	92	245

Source: Schedule IV-E-4.

The major purpose of this analysis, of course, is to provide a basis of comparison between fossil fuels and uranium. Of significance is the fact that the breakeven "prices" calculated with respect to both coal and oil are higher than the U_3O_8 price projections set out in Table 1.

The oil breakeven "prices" are substantially higher in all regions over the forecast period, as shown on Schedule IV-E-4. In addition, the differential between the U_3O_8 projected prices and the oil breakeven "prices" increases over time.

Thus, not surprisingly, on a price basis nuclear has a distinct advantage over oil. This substantial margin of advantage diminishes considerably when low sulfur coal is considered; however, the analysis shows the coal breakeven "prices" to be above the projected U_3O_8 prices on a national basis, and for the most part on a regional basis as well. On a national basis the differential between the coal breakeven "price" and the U_3O_8 projected price remains relatively stable over the forecast period by approximately $20 per pound. Regionally, there is a wide disparity in the projected breakeven "prices," although this tends to narrow by the year 2000. Yet the projected U_3O_8 prices remain below all regional breakeven "prices" with the exception of the South Atlantic region in the year 2000.

The previous discussion has shown that on the basis of inter-energy prices, nuclear power appears to have a distinct advantage over oil as well as coal, although to a much lesser extent. Based on this type of estimation, therefore, at least from the standpoint of fuel inputs, the incentive to expand nuclear power generation is apparent.

How do these conclusions compare to the projections of electric utility energy consumption made in the EEI study? The projection of total energy consumption in the utility sector under Case B is shown in Table 3. Also shown in Table 3 is the EEI projection of net generation under Case B.* The projection of total energy consumption in this sector is dependent upon this projection of generation. Under Case B, generation is projected to grow at an annual average rate of 5.4 percent per year from 1975 to 1985, and 5.1 percent per year from 1985 to 2000. Energy consumption is projected to grow by approximately 6 percent per year to 1985 and 5 percent per year thereafter.

TABLE 3

PROJECTED ENERGY CONSUMPTION & NET GENERATION IN THE ELECTRIC UTILITY SECTOR

Case B - Demand

Year	Energy Consumption (Q Btu)	Net Generation (Trillion Kwhr)
1975 (Actual)	20.1	1.98
1985	36.2	3.35
2000	75.4	7.11

Source: EEI, Economic Growth in the Future.

As discussed in Section B of this chapter, a modification to the projected EEI energy balance was required based upon the analysis of projected gas supply. The result of the modification shows that gas supply to the electric utility

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*A major stipulation of EPRI was the required use of the electricity projection developed by EEI.

sector would be essentially phased out by 1985. The deficit created by inadequate gas supply was assumed to shift to coal. The resultant projected energy consumption pattern is shown in Table 4.

TABLE 4

PROJECTED ENERGY CONSUMPTION IN THE ELECTRIC UTILITY SECTOR BY SOURCE OF ENERGY

EEI - Case B
(Q Btu)

Year	Gas	Petroleum	Coal	Nuclear	Hydro
1975 (Actual)	3.2	3.3	8.8	1.6	3.1
1985	-	3.0	17.5	11.8	3.8
2000	-	4.2	23.1	40.1	8.0

Petroleum consumption will remain essentially stable, while coal and nuclear power will account for the bulk of the increase. The most significant aspect in this projection is the substantial growth projected for nuclear power. Nuclear energy is projected to grow at an annual average rate of 8.5 percent per year from 1985-2000, and will account for approximately 53 percent of utility energy consumption by 2000. Coal is projected to grow at an average annual rate of 1.9 percent per year from 1985 to 2000, and will account for approximately 31 percent of utility energy consumption. Prior to 1985, however, coal is projected to grow at an annual average rate of approximately 7 percent over the 1975-1985 period.

Based upon the breakeven "price" estimate and the inferences drawn from a comparison of this estimate with the projected uranium prices, it appears that the growth in nuclear is a probable outcome, but not a definitive one. This outcome would, of course, be dependent upon the nature and degree of regulatory and environmental constraints affecting nuclear power in the future.

In summary, it cannot be stated with certainty that the projection of substantial nuclear growth will prevail, although it is within the range of possibilities. Rather, it must be recognized that circumstances, also wholly within the realm of reasonableness, could shift the nuclear balance toward coal.

APPENDIX TO SECTION E

MAJOR ASSUMPTIONS RELEVANT TO THE URANIUM BREAKEVEN ANALYSIS

The following is a list of assumptions underlying the calculations:

1. Typical plant size - nuclear, 1,000 mw; coal and oil, 800 mw.

2. Nuclear plant load factor - 67%; oil and coal - 70%.

3. Nuclear plant efficiency - 32.8% (based upon a net heat rate of 10,400 Btu per kilowatt hour); oil plant heat rate, 11,396; coal plant heat rate, 10,933.

4. Enrichment tails assay - 0.2% U^{235}.

5. Burn-up (MWD/MTU) - PWR equilibrium load, 17,183.

6. Losses during fabrication - 5.5%.

7. Losses during fuel preparation - 2.5%.

8. Enrichment - 2.154%.

9. Spent fuel assay - 1.016.

10. Conversion rate, uranium to U_3O_8 - 1.1793.

11. Loss in chemical reprocessing - 1%.

12. Loss in conversion to UP_6 - 0.3%.

13. Loss in fuel preparation that is recycled - 2%.

14. Loss in fuel fabrication that is recycled - 5%.

15. Loss in conversion of Yellow Cake - 0.5%.

16. Annual inflation rate, 3% compounded.

17. Nuclear fuel cycle costs (1975 $).

Conversion	1.55	$/Kg
Enrichment	77.25	$/Kg
Fabrication	72.10	$/Kg
Shipping	10.30	$/Kg
Reprocessing	103.00	$/Kg

18. Construction period, Nuclear (from issue date of construction permit) - 60 months; fossil-fired - 48 months.

19. Capital cost based upon CONCEPT III Computer Code (Construction locations per Census Region).

20. Cost of capital - 10% (interest charged to construction, 8.5%).

21. Carrying charge rate on investment - 16.75%.

22. Nuclear fuel payment schedule -

Uranium Ore - 2 payments of 50% each at 2 years and 1.5 years before operation.

Conversion - 1 payment of 100% 16 months before operation.

Enrichment - 1 payment of 100% 15 months before operation.

Fabrication - 8 payments of 10% each month starting 14 months before operation and 1 payment of 20% at operation.

23. Shipping and reprocessing occurs 4 months after refueling.

F. THE TRANSPORTATION SECTOR

The transportation sector represents a large proportion of U.S. energy consumption, currently about 26 percent. Petroleum, by far, is the most important fuel in that sector. In this study only future gasoline prices at the pump were analyzed. These prices were based on crude oil costs, refinery margins, and dealer margins. Other factors may affect gasoline prices, as discussed in this section. Also discussed briefly are other fuels consumed in the transportation sector.

The estimated 1975 consumption of energy in the transportation sector is presented on Schedule IV-F-1. The types of energy consumed by each mode are shown. The majority of the energy consumed is over 75 percent on the highways. Gasoline, of course, represents over 80 percent of this use. As a matter of fact, gasoline represents about 66 percent of all energy consumed in the transportation sector. Energy consumed by air travel is next important. Jet fuel dominates here. Railroad, vessels, and gas pipelines consume approximately the same proportions of energy. Fuel oil is mostly consumed by railroads and vessels, while compressor and other use of gas represents pipeline consumption.

Set out in Table 1 are the 1975 regular grade gasoline prices by Census Region. These prices exclude gasoline taxes, which vary from 9 cents per gallon to 14 cents per gallon depending on the area.

TABLE 1

REGULAR GRADE GASOLINE PRICES EXCLUDING GASOLINE TAXES
1975

Census Region	¢/gal.
New England	41.55
Middle Atlantic	42.71
South Atlantic	41.57
East South Central	40.63
East North Central	41.38
West North Central	40.59
West South Central	39.90
Mountain	42.44
Pacific	41.82

Energy consumption in the transportation sector is expected to increase just over 2 percent per year to 1985 and at a slightly lower pace to 2000. This is less than the historical rate. Also, this is somewhat lower than the expected growth of total energy consumption, according to EEI.* The slower growth is expected to result from lower demand because of higher prices and from more efficient use of fuel because of higher prices, mandatory efficiency standards set by the Government, and greater use of mass transit systems.

The EEI estimates future energy consumption in the transportation sector at 25.8 Q Btu in 1985 and 28.6 Q Btu by 2000.

The projected gasoline prices made in this study are presented on Schedule IV-F-2 for both the price control case and the free market case. There is little variation in the prices between the Census Regions. The Middle Atlantic region has slightly higher projected prices and the East and West South Central regions have slightly lower projected prices. These variations are primarily due to dealer margin differences which existed during the base period and are assumed to persist over the projected period. About a 3-cent per gallon spread exists between the price control case and the free market case in 1985, and this spread widens to about 8 cents per gallon toward 2000.

Gasoline prices are projected on the basis of supply and demand factors. There is essentially no competition with other fuels which would affect future prices. The gasoline automobile is virtually certain to dominate at least through the 1980's. Even in the 1990's there is no evidence at this time of any significant substitute.

Factors enumerated by EEI in causing a slow growth in demand for gasoline may have a tendency to keep gasoline prices below or at the projected levels. For example, if mass transit is used to a greater extent, and car traveling to a lesser extent, this would affect the supply and demand and therefore the price for gasoline.

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*EEI, Economic Growth in the Future, June 1975.

While the prices of other fuels consumed in the transportation sector were not analyzed in-depth, a number of observations can be made related to the projected prices of these fuels.

Jet fuel is presently priced a little over one cent per gallon higher than distillate fuel oil. This differential may well remain the same or slightly increase in the future. Therefore, the projected price of distillate fuel oil at the refinery (see Chapter III-C), plus one cent per gallon and plus a nominal pipeline cost to the airport, could be a fair estimate of future jet fuel costs.

Diesel fuel consumed on highways, by railroads and in vessels, costs about the same or slightly more than distillate fuel oil at the refinery. To this must be added the transportation and distribution costs which will also depend on volume. The consumers of diesel fuel could be considered as larger volume users, except for highway diesel use; therefore, the industrial transport price for distillate fuel oil might represent a reasonable estimate for the future costs of diesel. The highway diesel use would be priced closer to the tank wagon price of distillate fuel oil, which is higher than the industrial price because of the higher distribution margin (see Chapter III-C).

Residual oil consumed by vessels is bunker fuel. There is presently only a slight difference between the price of bunker fuel and high sulfur residual fuel oil consumed by stationary users; therefore, that projected price might represent the future price for bunker fuel (see Chapter III-C).

Finally, natural gas pipelines use natural gas as compressor fuel. The cost of that gas is the price the pipelines pay for their gas supply, purchased in the field, at the plant, or at points of importation. Prices of natural gas were projected at these points and these projections would represent the future price of gas used in the transportation sector (see Chapter III-D).