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INDUSTRIAL FUEL CHOICE
ANALYSIS MODEL

Volume I
PRIMARY MODEL DOCUMENTATION

F I R S T D R A F T

Prepared for:

DEPARTMENT OF ENERGY
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Washington, D.C.

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1. OBJECTIVES AND SCOPE

1.1 PURPOSE

The Industrial Fuel Choice Analysis Model (IFCAM) is an energy demand model developed in response to the need to evaluate fuel choice decisions in the industrial sector over a 10-15 year forecasting horizon.

In terms of the national energy goal to reduce reliance on imported supplies of oil and natural gas, the industrial energy uses are a critical sector. In 1974, industrial demands (excluding utilities) accounted for 24 percent of U.S. oil consumption and 42 percent of natural gas use.^{1/} The reduction in national reliance on scarce fuels can be achieved by energy conservation and shifts to more abundant energy sources such as coal, nuclear, or solar. The potential to increase our dependence on coal lies in the electric utility and industrial sector. The utility sector already is moving almost entirely to coal and nuclear energy in new facilities. The only major fossil fuel choice issue for utilities is the rate (and costs) of phasing out existing oil- and gas-fired units. Coal use in the industrial sector, on the other hand, has only recently experienced a leveling off of a secular decline in coal utilization. The industrial sector, given its technical capability and incentives to minimize energy costs, is by far the largest single potential market for the shift from scarce fuels to coal.

Another critical factor is the demand for natural gas by the industrial sector. The availability (and price) of gas for new residential/commercial facilities hinges critically on the effects of natural gas price deregulation and curtailment policies on industrial sector gas usage. Critical factors include the extent to which natural gas may be required to maintain product integrity in industrial energy uses and what gas price will drive industrial energy users to shift to fuel oil or coal. In effect, the

industrial sector is the "swing" sector for natural gas in the economy. The importance of the industrial sector was reflected in recent debates over fuel pricing policies and investment incentives in the National Energy Plan (NEP).

Unlike the utility sector, in which many sophisticated models have been developed to analyze fuel use,^{2/} quantitative models focusing on industrial sector energy use are only in early stages of development. Nearly all existing models are highly aggregated and are based on historical econometric or input/output relationships.^{3/} IFCAM was developed to fulfill a demand for a highly disaggregated process engineering model which can realistically reflect factors affecting fuel choice decisions in diverse industrial energy applications.

1.2 MODEL CAPABILITIES

1.2.1 Policy Focus

The design and capabilities of IFCAM were guided by the emphasis placed by the Department of Energy (DOE) on the analysis of the impacts on the industrial sector of energy policy measures proposed in April, 1977, in the NEP and debated since that date in the Congress. The model structure was developed to analyze the impacts on industrial fuel choices of four sets of factors: fuel prices, government energy policy proposals, the costs associated with firing alternative fuels, and other key model parameters such as the size distribution of new industrial boilers.

1.2.1.1 Policy Measures

IFCAM is capable of analyzing four classes of energy policy measures: fuel taxes, investment incentives, energy regulatory policies, and environmental regulatory policies. Fuel tax measures, considered during the debates on energy policy and analyzed with an earlier version of the model, reflected a variety of considerations affecting fuel tax rates, tax coverage, and special exemptions. Table 1.1 shows the parameters considered in analyzing a variety of complex tax schemes.

TABLE 1.1 FACTORS AFFECTING FUEL TAX LIABILITY

New/existing facilities

Industrial sector (textiles, mining)

Minimum corporate energy use

Minimum plant energy use

Type of combustor (boiler, process heater)

Technical capability to use coal

Combustors already designed to fire coal

Region-specific tax rates

Combustor size

Environmental problems

Self-generating electricity

Fuel type

Intra- or interstate natural gas

Remaining depreciable life of combustor

A variety of tax credits and changes in the tax treatment of capital proposed to provide incentives to invest in coal-related equipment were analyzed using the model. The types of measures considered are listed in Table 1.2 and reflect every (or almost every) conceivable wrinkle in the tax codes which could shift fuel choice decisions towards coal.

Energy regulatory policies were evaluated which targeted specific types of industrial energy uses including new boilers, minimum size units, existing boilers designed to fire coal, new process heaters technically capable of using coal, and indirect-fired process heaters. Special exemptions, such as when environmental problems were severe, were considered. Economic feasibility was considered by testing the impact of various interpretations of provisions such as exemptions when the cost of using coal substantially exceeds the cost of imported oil.

Environmental regulatory policies which could affect fuel choice decisions also can be considered in IFCAM. These regulations can affect fuel choice by altering the relative costs of burning alternative fuels and/or by prohibiting coal-burning sources in certain areas with severe air quality problems. Regulations relating to particulate and sulfur dioxide emissions from fuel-burning sources included state and local regulations, federal new source performance standards, and new source controls in nonattainment areas.

1.2.1.2 Fuel Prices

The model can simulate the impact of alternative fuel price scenarios on the industrial fuel mix. Fuel prices for distillate fuel oil, high and low sulfur residual fuel oil, new and "old" natural gas, and low and high sulfur coal were considered in the model.

1.2.1.3 Capital and Operating Costs of Alternative Fuels

Quite clearly, the fuel choice decision is sensitive to non-fuel costs of burning alternative fuels. While the best available cost data were used, the model can evaluate the impact of any alternative cost estimates.

TABLE 1.2 INVESTMENT INCENTIVES

Raising the investment tax credit (ITC) on
coal facilities

Altering the type of capital expenditures eli-
gible for the ITC

Eliminating the ITC for oil and gas facilities

Reducing the depreciable life of coal facilities
(accelerated depreciation)

Extending the depreciable life of oil/gas facilities

Altering the depreciation method (requiring straight
line methods for oil and gas facilities)

Allowing a rebate of fuel taxes as a credit for coal
related investments

1.2.1.4 Sensitivity to Other Key Parameters

In addition to these three sets of factors, many other key variables affect the potential for coal use. The model is designed, for example, to test the alternative judgments of the technical capability to use alternate fuels, to evaluate the effects of varying industrial growth rates, to alter the size distribution and operating characteristics of new combustors, and to alter development lead times for new coal-using technologies.

1.2.2 Model Outputs

The model generates complete model outputs for 1985, 1990, and 1995. These outputs, providing fuel mix results in either absolute amounts or as distribution percentages, are available under several formats. The fuel use figures can be presented by new or existing combustors, functional uses (boilers vs. process heaters), nine industry sectors, and ten regions. Boiler results also can be broken down by size and capacity utilization. Fuel choice decisions are sufficiently disaggregated so that IFCAM is capable of providing fuel mix outputs for 244 Air Quality Control Regions (AQCR's) and 48 types of process heaters. However, this degree of disaggregation is performed to determine more realistic environmental requirements, equipment cost variations, and technical ability to fire coal; these more disaggregated results are not normally presented as model outputs.

The model also can provide outputs related to the cost, tax, and environmental impacts associated with an energy scenario. These related outputs are not included routinely in the standard format, but can be generated to satisfy specific needs.

1.3 SCOPE AND COVERAGE

1.3.1 Relationship to DOE's MEFS Model

The DOE has used the Mid-range Energy Forecasting System (MEFS) model as its basic forecasting tool and as the means of insuring consistent energy

accounting. It is a general equilibrium model which solves for energy prices, the level of energy consumption, and the mix of energy sources by region and major consuming sector. The MEFS industrial demand sector is a two-sector model (petroleum refining and other industry) based primarily on econometric relationships calculated from historical data.^{4/}

IFCAM was developed in part to provide MEFS with an alternative source of forecasts of industrial fossil fuel energy demands. As a consequence of this specification, the model was designed to operate as consistently with MEFS as possible. IFCAM was structured to use MEFS estimates of overall industrial fuel demands and to focus on the mixture of fossil fuel uses in this sector. IFCAM is capable of providing results for the same periods covered by MEFS, i.e., through 1995.

1.3.2 Other Coverage Issues

The model covers fuel uses in the industrial sector including manufacturing, mining, and construction. IFCAM considers only steam coal demands and excludes feedstock energy uses, including metallurgical coal and petroleum- or natural gas-derived raw materials used in chemical processing.

Both the lack of time and the relatively short time horizon limit the choice of energy supply technologies covered. For coal, the model covers only technologies where coal is burned as a solid fuel. Not specifically considered are coal-based alternatives such as process changes, shifts from direct to indirect firing, increased electrification, or coal conversion technologies such as gasification or liquefaction. The mid-term time horizon of IFCAM precludes significant market penetration of many of the advanced coal-based technologies which are still in the development stage. To the extent that commercially available technologies, such as low-Btu gasification from coal, which are excluded from IFCAM will be adopted, the model tends to understate the potential for coal utilization. In some specific scenarios, EEA has run its other industrial energy demand model, which has a longer time horizon and considers advanced technologies, to

estimate possible market penetration by 1990 and 1995 of advanced coal-based technologies.^{5/}

FOOTNOTES

1. Energy and Environmental Analysis, Inc., "Energy Consumption Data Base," Vol. 1, Summary Document, prepared for Federal Energy Administration, June 9, 1977.
2. Two examples are: Coal and Electric Utilities Model, prepared by ICF for the Federal Energy Administration, and "Benefit Cost Analysis of Laws and Regulations Affecting Coal," prepared by EEA for the Department of Interior, July, 1977.
3. Department of Interior, Bureau of Mines, U.S. Energy Through the Year 2000, and Massachusetts Institute of Technology, MIT Econometric Model. Most of the highly disaggregated industrial energy use models are in the preliminary stages of development.
4. Federal Energy Administration, National Energy Outlook, February, 1976.
5. Energy and Environmental Analysis, Inc., "Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000," draft document prepared for the Department of Energy, April 28, 1978.

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2. OVERVIEW OF ANALYTICAL FRAMEWORK

2.1 INTRODUCTION

This section outlines the structure of IFCAM, describes what factors are considered in evaluating fuel choice decisions, indicates how and at what level of detail industrial energy use is characterized in the model, and highlights key inputs to the model. The method of interaction between IFCAM and MEFS also is described. In addition, the organization of this documentation report is detailed at the end of the section.

2.2 OVERVIEW OF MODEL LOGIC

IFCAM is an industrial energy demand model which focuses on fuel choice decisions. Figure 2.1 outlines the model structure, identifying key inputs, outputs, and major analytical steps.

Inputs 1, 2, and 3 - Energy Demand and Industrial Production: The level of industrial fossil fuel demand and nine industrial production growth rates by region are critical inputs into IFCAM. Although such inputs could be derived from many sources, in the past they have been taken from the historical Energy Consumption Data Base (ECDB), MEFS projected energy use, and the macroeconomic model which drives MEFS.

Model Step #1 - Characterization of Industrial Energy Use: This initial step breaks down the projected fossil fuel use by industrial sector, new and existing facilities, type of combustor (e.g., boiler, blast furnace, glass melter), size of combustor, and a variety of other classifications.

Model Step #2 - Create and Site Individual Combustors: Energy uses from Step #1 are disaggregated into classes of individual combustors prior

FIGURE 2.1 MODEL STRUCTURE

to further analysis. These combustors then are sited in 244 AQCR's according to historical patterns of industrial location.

Model Step #3 - Assignment of Environmental Regulations and Pollution Control Strategies: Emission limits for major coal- and oil-related pollutants applicable to individual combustors are assigned based on state and federal regulations. Possible pollution control strategies which can satisfy these regulatory requirements are identified.

Input 4 - Fuel Prices and Energy Policy: Specifications for a particular model run and projection year are input at this step. Specifications include the fuel price scenario, applicable fuel taxes, financial parameters, and energy regulatory policies.

Model Step #4 - Technical Potential to Substitute Fuels: In this step, a set of criteria related to the technical capability to use alternate fuels, lead time factors, and general economic considerations are applied to screen out fuel uses not technically capable of using residual oil or coal. The energy uses screened out must select either distillate oil or gas.

Model Step #5 - Environmental Constraints: The costs of satisfying environmental requirements will be factored into the economics of fuel choice in Step #6. However, to the extent that environmental considerations may effectively block siting of new coal-fired combustors or conversions in existing units, this step screens out coal-fired units in severe air quality problem areas.

Model Step #6 - Economics of Fuel Choice: Based on the characteristics of each combustor (size, operating rate, useful life, combustor type, pollution control requirements, etc.), capital and non-fuel operating costs are generated for the option of choosing oil, gas, or coal. The least cost fuel then is selected which minimizes the present value of the cost of

generating energy over the combustor life. If the fuel type selected in this criterion is constrained due to technical or environmental reasons, the second least cost fuel alternative is chosen.

Model Outputs: The model categorizes fuel choice decisions by industry, functional use, and new/existing status. The fuel mix reflects the most economic fuel choice between natural gas, distillate fuel oil, low or high sulfur residual fuel oil, low or high sulfur coal, and refinery gas.

Each of the model steps outlined above is discussed in greater detail below.

2.3 MAJOR ANALYTICAL STEPS

2.3.1 Inputs of Fossil Energy Demand and Industrial Production

IFCAM focuses on the choice between coal, oil, and gas with the level of fossil fuel demand specified as an exogenous input. To date, for each of the 10 federal regions, total fossil fuel demand for all industry has been generated by MEFS.

The MEFS model is a general equilibrium energy model which relies on the Data Resources, Inc. (DRI) macroeconomic model to provide the economic trends which drive the growth in energy demand. Since MEFS provides only aggregate industrial fossil fuel demand,* regional industrial production growth rates for nine sectors are provided by the DRI model runs. These industrial production growth rates are used in IFCAM to capture shifts in energy demand among the major energy consuming industries.

2.3.2 Characterization of Industrial Energy Use

In this first model step, aggregate fossil fuel demand inputs are disaggregated to characterize industrial energy use by factors such as functional

* MEFS only distinguishes between petroleum refining and all other industrial energy uses.

use, fuel type, combustor size and location, and operating practices. These factors, discussed below, are significant because they:

- Alter the costs of using alternative fuels (e.g., fuel costs vary according to industrial location).
- Determine the economics of fuel choice (e.g., whether the combustor operates at a high capacity utilization rate).
- Distinguish elements of energy use specifically targeted by energy policy measures (e.g., new boilers above a cutoff size).
- Are needed to generate required model outputs.

A major characteristic of industrial energy use is functional use. IFCAM breaks down fuel use by over 40 process applications such as tubestill heaters used in atmospheric distillation in petroleum refineries, cement kilns, metal reheating furnaces, glass melters, and boilers. Categorization by functional use is important because the technical capability to use residual oil or coal in many processes varies due to problems of product contamination, corrosion, temperature control, and current equipment design. The costs of burning alternative fuels also vary significantly among process applications.

In addition to classifying combustors by functional use, combustors are classified as to whether they are new or existing facilities, what type of fuel they were designed to fire, and whether they can be retrofitted to fire alternate fuels.

Combustors also are categorized by factors such as size and location which affect the costs of burning alternative fuels. Four size classes are distinguished for boilers and one to three size classes for each process heat application. The location of the fuel user is important since fuel users in New England must pay higher prices for coal relative to scarce fossil fuels than fuel users in the Midwest.

Combustors also are classified according to useful life and operating practices, both of which influence the economics of alternative fuels. For

boilers, up to 54 energy use cells are created to distinguish annual rates of capacity utilization by industry and combustor size. For each process heat application, one to three capacity utilization rates are distinguished. Since combustors with relatively long useful service lives will tend to be more likely to select coal, useful lives are characterized by process application between new and two vintages of existing combustors.

Energy use also is disaggregated into nine industrial subsectors which differ with respect to growth rates, regional dispersion, technical capability to use alternate fuels, and the other characteristics distinguished above.

2.3.3 Creation of Individual Combustors

Fuel use was classified into individual combustor units (Step 2 in Figure 2.1) according to location (region), size, capacity utilization, and industry. AQCR is the only level of additional detail (244 AQCR's) developed in this step. There are several reasons to proceed to this higher level of disaggregation. First, environmental regulations for all existing combustors and many new fuel-using facilities vary among states and counties within states. Since environmental control costs are a major factor affecting the economics of fuel choice, IFCAM is designed to reflect this variation in environmental costs.

Second, individual combustors are sited in AQCR's to avoid distortions caused by multiplying distributions of fuel use by regulation to aggregate energy use cells. For example, if discrete units are not created, multiplying aggregate distributions could result in a fuel use estimate of 1000 MMBtu/year in a boiler with a design firing rate of 100,000 pounds of steam per hour operating at 5000 hours per year; total fuel use actually would be approximately 700,000 MMBtu/year.

Third, this more disaggregated level provides a framework to:

- Distinguish more specialized environmental requirements (as IFCAM does for nonattainment regions).
- Portray delivered fuel price variations in a more realistic manner at a future date (e.g., currently, Houston and Dallas face the same delivered coal prices).

Existing boilers are sited in their actual locations while new boilers and all process heaters are located according to historical (within federal region) patterns by AQCR. While current locational patterns are crudely estimated, AQCR siting provides a framework for more sophisticated facility siting algorithms at a future date.

2.3.4 Technical Potential to Use Substitute Fuels

The next model step is to identify the industrial fuel uses that clearly would not select coal or residual oil due to technical constraints, timing considerations, or broad economic factors. In the case when residual oil and/or coal are technically infeasible, the economic alternatives are limited to distillate oil or natural gas.

An evaluation of technical potential considers the following factors:

- Technical capability to use coal or residual oil.
- Lead times to develop new coal-firing technologies.
- Lead times to order new equipment.
- Supply-related constraints on coal use.

While coal firing is a proven technology in boiler applications, coal currently is used in only a few process heat applications. Consequently, IFCAM incorporates a judgment of the technical feasibility of coal use for major process heat applications, ranked according to the risk of equipment failure. When new equipment designs must be developed, lead times for the design and operation of demonstration facilities are included. These technology development lead times, which range from three to six years, will limit severely the applicability of coal firing in process heat applications in the 1985-90 time frame. A similar distinction is made for residual fuel oil when technical problems preclude its use.

In considering the impact of proposed energy policy decisions, IFCAM also incorporates lead times for the construction of new facilities. For example, the construction lead time for a new boiler is typically between two and three years. Thus, when considering the impact of a legislative action passed in 1978 on fuel choice decisions, only those boilers coming on line after 1980 are likely to reflect a response to such policy measures.

Supply-related constraints that could limit coal use include the availability of coal supplies, production capacity limits on new boilers, and environmental control equipment. These constraints are not incorporated specifically into the model logic and have been analyzed separately, given the demands implied by a specific model run.

2.3.5 Other Environmental Constraints

In addition to technical constraints, environmental constraints limit the fuel choice alternatives viewed by industry. Environmental regulations that tend to increase coal and oil capital and operating costs are discussed separately below; however, some combustors that would select coal under a purely economic criterion may be blocked from conversion due to severe environmental problems within an AQCR.

This step attempts to account for this phenomenon by identifying AQCR's that are classified by EPA as "nonattainment" due to a major coal pollutant: total suspended particulates (TSP), sulfur dioxide (SO₂), or nitrous oxide (NO_x). The nonattainment specification actually applies to sub-AQCR levels and the model attempts to classify fuel at this level as attainment or nonattainment. Then, to simulate a strict environmental control scenario, oil and gas are not allowed to be replaced by coal. Since environmental restrictions in nonattainment areas actually increase costs rather than block coal use, this "environmental blocking factor" should tend to overstate the reduction in coal use.

2.3.6 Assignment of Environmental Regulations and Pollution Control Strategy

Environmental regulations play an important role in determining the level of fuel substitution. Environmental regulations may increase the capital and fuel costs that a coal or residual fuel oil conversion candidate would face by increasing the environmental control required or quality of fuel burned. The specific regulations vary geographically (AQCR), by combustor size and type, and by type of fuel.

Environmental regulations on a state and federal level were examined for two pollutants: SO_2 and TSP. Regulations are developed for three categories of combustors in IFCAM: boilers subject to Federal Standards of Performance for New Stationary Sources (commonly referred to as "new source performance standards," or NSPS), boilers not subject to NSPS, and process heaters.

State and local regulations in many areas are being revised, especially where air quality standards are not being attained. IFCAM model runs have used only current regulations although revised regulations can be inserted easily. The federal NSPS regulations for new boilers are being revised to conform to recent Clean Air Act amendments. Several alternative versions of this important federal regulation have been used to evaluate the impacts of alternative regulatory scenarios on projections of fossil fuel demand.

For a given set of regulations, a mix of environmental control equipment, such as flue gas desulfurization (FGD) or electrostatic precipitators (ESP), and low sulfur fuel which could satisfy the regulation is specified. The various possible mixes later are used to identify the capital and operating costs for different fuel types associated with each combustor.

2.3.7 Fuel Prices and Energy Policy Inputs

The model can analyze fuel price variations and two types of energy policy measures: tax policies which affect the economics of fuel choice and regulatory programs such as the Powerplant and Industrial Fuel Use Act of 1978 (PIFUA).

Fuel price variations are used in IFCAM to model fuel taxes, natural gas deregulation, or variations in price trajectories. Fuel prices can be varied according to seven fuel types: distillate fuel oil, high and low sulfur residual oil, high and low sulfur coal, and average and marginal gas markets. The price of each fuel type can differ by region.

Investment incentives considered have primarily focused on differential depreciation methods for coal, oil, or gas and on increased ITC's in alternative fuels. The impacts of differential depreciation methods and investment incentives are handled within the scope of the main model logic (Step 6 in Figure 2.1).

The coal conversion regulatory program established under PIFUA targets boilers whose rated capacity is over 100 MMBtu/hr. An economic test which compares coal to an imported oil price is used to simulate legislative provisions related to economic exemptions. This and other regulatory provisions have been programmed in a special IFCAM routine and the model projects the level of increased coal use under the program, in the absence of any implementation problems.

2.3.8 Economics of Fuel Choice

This section presents the method for simulating the fuel choice investment decision for the industrial sector. For each of the combustors, the costs of high and low sulfur coal were compared with those of using each of the other fossil fuel alternatives (distillate oil, gas, and low and high sulfur residual oil). The comparison was simulated on the combustor level and employed a standard net present value (NPV) calculation as the investment criterion. An economic fuel choice was calculated for each combustor. In cases when technical or environmental problems precluded a certain fuel choice, the next best economic alternative was chosen.

The major components considered in the NPV calculation are shown below:

- Capital cost.
- Construction period.
- Revenue life.
- Depreciation life and method.
- Expensible construction costs.
- Investment tax credit (ITC).
- Discount rate.
- Fuel price.
- Annual fuel consumption.
- Property tax.
- Operating and maintenance costs.
- Corporate tax.

The components of NPV can be divided into three major subsets: policy inputs, standard model assumptions, and key model variables. Policy inputs are depreciation life and method, ITC, and fuel prices. Standard model assumptions are construction period, corporate tax rate, expensible construction costs, and property tax. These elements do not vary by combustor characteristics and represent standard investment assumptions. Key model variables, capital costs, revenue life, discount rate, annual fuel consumption by capacity utilization and size, and operation and maintenance (O&M) costs, all vary with factors considered in the model and are discussed below.

Capital cost components were developed for each fuel type as a function of combustor type, size, and environmental control requirements, according to new or existing status and the prior fuel design. Capital cost components were calculated for each combustor. For example, when considering coal use, if an existing oil boiler previously had burned coal, then only the retrofit costs of converting back to coal would be considered in the NPV, while an existing boiler which had never burned coal would be required to completely replace the oil unit with coal. This early replacement unit would consider the full cost of a coal boiler in determining the capital cost input into the coal NPV. A new unit, on the other hand, would simply look

at the cost of coal, oil, and gas for new units in evaluating an investment decision.

Operating and maintenance costs did not vary by the new/existing status of a combustor but did change with regard to combustor type, fuel type, size, capacity utilization, and environmental control required. Similarly, annual fuel consumption was simply a factor of fuel type, size, capacity utilization, and assumed efficiency.

The discount rate used for the NPV represented the hurdle rate or required rate of return on an investment. Much uncertainty surrounds the actual value of discount rate that should be used; however, it was designed conceptually to take into account the cost of capital, perceived risk of using coal, and an investment priority scheme. The cost of capital includes assessment of costs of debt and equity with industrial average debt/equity ratios used to weight the costs. The perceived risk portion of the discount rate is included to account for the uncertainty associated with burning coal. Changing environmental regulations and uncertainty of future coal availability contribute to the phenomenon whereby a firm may require higher expected returns on investments in order to make coal investments. These factors are modeled as constant across both new and existing combustors. The third factor, investment priority scheme, was factored into discount rates used to assess conversions of existing facilities to coal.

New fuel-using combustors are necessary to provide steam or process heat to meet increased industrial production goals or to replace worn-out facilities. On the other hand, conversions of existing facilities to an alternative fuel choice would be undertaken solely to reduce energy costs and are not tied to satisfying production goals. These "discretionary" investments in existing fuel-using facilities are required in IFCAM to pass a more severe hurdle rate test than for new combustors in order to simulate capital rationing schemes currently applied in the industrial sector.

The economic analysis was used to evaluate both the additional ITC incentives and the fuel tax incentive of the energy proposal. In the actual analysis, the NPV of capital cost for all the possible environmental control scenarios and fuel types was calculated for each combustor. Similarly, NPV of O&M costs for the corresponding categories was calculated. These NPV's were matched up to the appropriate NPV of the price stream for each fuel type that could be burned in the combustor, and a least cost fuel was determined. The model, in effect, chooses the least cost fuel and associated environmental control strategy within the limits of the technical feasibility and environmental constraints.

2.3.9 Outputs

The basic outputs from the model are oil, gas, and coal demand after all the incentives and fuel type constraints have been evaluated. As illustrated in Figure 2.1, fuel use is determined based on three constraints: technical, economic, and environmental. Note that no financial or supply-related constraint is explicitly factored into the analysis. The fuel selection of oil, gas, and coal use is displayed by region and industry. Additional detail is available (e.g., by combustor type, new/existing status) depending upon the objectives desired. Cost or environmental impacts also can be generated for specific objectives.

2.4 INTERACTION OF IFCAM WITH MEFS

IFCAM and MEFS have been used in tandem to estimate industrial oil, gas, and coal demand under various incentive programs. This section discusses the interaction process between the two models to produce a final fuel demand incorporating general price/demand relationships, combustor-specific economics, and an overall conservation estimate.

The MEFS model accounts for general price/demand interactions between all sectors of the economy by region. IFCAM accounts for micro-level investment decisions using prices and fossil energy levels as inputs. The ideal way to join the two models would be to run them interactively until simul-

taneous solutions were reached. However, because extensive effort is required for each model run, this procedure typically was followed using only one iteration step.

The MEFS model was run with base case price and economic growth assumptions. Total scarce fossil fuel demands were input into IFCAM at a regional level. IFCAM model run results then were input back into MEFS, overriding the fuel mix demand equations in MEFS with the IFCAM estimate of regional fuel use. Higher fuel prices, such as those associated with fuel taxes, also were input from IFCAM back into MEFS. The MEFS model then was run again to determine the energy conservation impact of higher fuel prices.

2.5 ORGANIZATION OF THE REPORT AND DESCRIPTION OF SAMPLE MODEL RUN

2.5.1 Organization of the Documentation

The remaining sections of this report present a more detailed description of the model steps covered in the above discussion. Sections 3 through 7 cover the details of model logic and data sources, supported by the accompanying appendices. Section 8 presents a sample run, including the fuel price energy growth and policy assumptions behind the run as well as the resulting fuel mix. The sections are presented in slightly different form than in Figure 2.1, so an outline is presented below matching model steps and inputs with the appropriate section of the report.

<u>Report Section</u>	<u>Model Inputs and Steps</u>
3: Industrial Energy Consumption	Inputs 1&3: fossil fuel demand in 1974 and 1985 Input 2: industrial production growth Step #1: characterization of industrial energy use - industrial portion
4: Characteristics of Oil and Gas Use	Step #1: characterization of industrial energy use - detailed classifications

<u>Report Section</u>	<u>Model Inputs and Steps</u>
5: Technical and Other Constraints to Coal and Oil Use	Step #4: technical potential to use coal and oil
6: Assignment of Environmental Regulations and Pollution Control Strategies	Step #3: environmental requirements Step #5: environmental constraints to conversion
7: Economics of Fuel Choice	Input 4: fuel prices and energy policy Step #6: economics of fuel choice
8: Sample Run	Energy Impacts

Appendices are included in Volume II of this report. They describe some of the key data bases used in this model, present parameter values for key nonboiler characteristics, and detail assumptions and data sources for the projection methodology and all model cost data (capital, annual O&M, and fuel expenses).

2.5.2 Use of Sample Runs in Model Documentation

In Sections 1 through 8, a sample model run is tracked step by step to clarify the exposition of the model logic, describe the nature of IFCAM output, and illustrate the fuel choice issues for the variety of industrial sector energy uses. The sample run is intended to illustrate the detail of the extensive data characterization performed in the model as well as the quantity of fossil fuel consumption affected by technical, economic, environmental, and regulatory considerations. The sample run was chosen to illustrate the analytical capabilities of the model and includes several of the major provisions evaluated in the energy legislative process to illustrate how such provisions were modeled.

Major exogenous inputs to IFCAM are:

- Regional fuel prices by year.

- Regional total fossil energy demands by year.
- Regional production growth rates by year and by industry.

The industrial growth rates and total fossil energy demands are described in Appendix E and Section 3. The methodology for deriving the fuel price forecasts is presented in Appendix L and Section 7. An overview of the major assumptions and background for the sample run is discussed in Section 8 along with the aggregate model output.

3.. INDUSTRIAL ENERGY PROJECTIONS

3.1 INTRODUCTION

This section describes the first step used in characterizing industrial fuel use -- transforming MEFS inputs of potential coal, oil, and gas demand into scarce fuel demands by major industrial sectors. The decision to use MEFS to provide the macro-level inputs to IFCAM was made by DOE. Although a variety of models could be specified, the MEFS model allowed DOE easy access and in-house expertise while also maintaining consistency with the analysis of the utility energy conservation program.

Introductory parts of this section include definitions of the fuel uses covered in NGPM and an overview discussion of industrial fuel use according to industry and major functional uses.

3.2 COVERAGE OF ENERGY IN IFCAM

The primary data sources used for energy consumption information in IFCAM were the ECDB^{1/} and the MEFS model. The ECDB contains historical fuel consumption data disaggregated by industry, region, and fuel type. MEFS projects total industrial energy consumption levels by region and fuel type in 1985, 1990, and 1995 from a 1975 baseline.

Since the fossil energy demand estimates used as inputs into IFCAM were derived from MEFS, the first step in developing an industrial energy data base was to reconcile the definitional differences in the ECDB and MEFS historical data bases. In IFCAM, the industrial sector is defined as all manufacturing, mining, agriculture, and construction sectors of the economy.

MEFS 1975 energy use data are based on Bureau of Mines (BOM) information. Table 3.1 illustrates the way ECDB total energy use was adjusted to be con-

TABLE 3.1 ADJUSTMENTS TO ECDB INDUSTRIAL ENERGY USE
(1974 data)

	<u>Coal</u>	<u>Oil</u>	<u>Gas</u>	<u>Other</u>	<u>Total</u>
Original ECDB	3.7	8.6	8.6	4.4	25.3
Less:					
raw material and feedstock	2.4 ^{a/}	1.9	0.5	---	4.8
LPG	---	0.2	---	---	0.2
byproduct fuels	---	1.0 ^{b/}	---	0.9 ^{c/}	1.9
electricity	---	---	---	2.4	2.4
other definitional	---	2.6 ^{d/}	---	1.0 ^{e/}	3.6
Adjusted ECDB (1974)	1.3	2.9	8.1	---	12.3
MEFS (1975)	1.4	3.3	8.3	---	13.0

a/ Metallurgical coal.

b/ Refinery (still) gas.

c/ Primarily wood residuals.

d/ BOM/MEFS defines all gasoline and diesel fuel consumption in the transportation sector. BOM/MEFS defines all asphalt in the commercial sector.

e/ Fuels in ECDB that are not classified by fuel type due to Census reporting errors or incomplete data. As much as 0.5 quads of natural gas may be misclassified here.

sistent with energy coverage in MEFS. Adjustments to the original 25.3 quads of energy in ECDB reduced fossil fuel coverage to 12.4 quads. Electricity use was excluded since IFCAM focuses only on fossil energy demand. Raw materials, feedstocks, and liquefied petroleum gas (LPG) were excluded because the energy policy issues to be analyzed using the model do not focus on these fuel uses. In addition, MEFS provides demand estimates of these fuel uses. Byproduct fuels (such as coke oven gas or bark) are not covered in MEFS energy concepts, although these energy sources are substitutes for scarce fossil fuels. Adjustments classified as other definitional conform to MEFS accounting procedures which transfer all gasoline and diesel oil demands in construction and agriculture into transportation energy demands. Similarly, asphalt was shifted into the commercial sector.

The adjusted ECDB fossil fuel coverage used in IFCAM accounts for nearly one-half of total industrial demand and 64 percent of scarce fuel use in the industrial sector.

3.3 OVERVIEW OF INDUSTRIAL ENERGY USE

The adjustments described above limit the focus of IFCAM to scarce fuels which accounted for over 12 quads or 24 percent of total U.S. oil and gas demand in 1974.

Industrial oil and gas use can be divided into three major functional uses; boilers, feedstock, and process equipment. Table 3.2 illustrates this breakdown by functional use and major industrial sectors. Process heat is the major use, comprising 45 percent of total oil and gas consumption, while boilers and feedstocks make up 34 and 16 percent, respectively.

Boilers generally comprise all uses which create steam. Process steam, most types of space heating, and electricity generation (except gas turbines) all are classified as boiler uses. The chemical, paper, petroleum, and food industries consume nearly 60 percent of scarce fuels burned in boilers.

TABLE 3.2 OIL AND GAS CONSUMPTION BY FUNCTIONAL USE IN 1974^{a/}
(quads)

SIC Code ^{b/}	Major Group	Boiler ^{c/}	Raw Materials	Process Equipment	Other ^{d/}	Total	% of Total Industrial Fuel Use
20	Food	0.40	-----	0.10	0.10	0.60	4
22	Textiles	0.13	-----	0.03	-----	0.16	1
26	Paper	0.71	-----	0.15	0.13	0.99	7
28	Chemicals	1.10	2.30	0.50	0.28	4.18	29
29	Petroleum	0.63	-----	2.20	0.05	2.88	20
32	Stone, Clay and Glass	0.02	-----	0.80	-----	0.82	6
33	Primary Metals ^{f/}	0.30	0.10	1.10	0.20	1.70	12
All Other Industry ^{g/}		<u>1.63</u>	<u>-----</u>	<u>1.64</u>	<u>-----</u>	<u>3.27</u>	<u>21</u>
Total Industry		4.92	2.40	6.52	0.76	14.60 ^{e/}	100

a/ Includes LPG, feedstocks, and refinery (still) gas.

b/ Standard Industrial Classification.

c/ Process steam production and electricity generation.

d/ Space heating and cooling, lighting, coke production, machine drive, other uses not specified by kind, and data not elsewhere classified.

e/ Fuel use is the adjusted ECDB oil and gas with feedstocks, raw materials, and byproduct fuels added back in to illustrate the major functional uses.

f/ Includes Steel and Aluminum.

g/ Functional uses of oil and gas by other industries were derived from functional shares of total energy use by all manufacturing sectors. (EEA, Energy Consumption Data Base, Volume 1 - Summary Document, prepared for FEA, June, 1977).

Process uses constitute a larger portion of total industrial scarce fuel use than do boilers and comprise a very diverse range of uses. Process uses include petroleum tubestill heaters, cement kilns, steel reheaters, and brick refractories, to name just a few.

Feedstocks identified here include coal, oil, or gas which is used as a raw material to create an end product. Most oil and gas feedstocks are found in the chemical industry; a small portion of these feedstocks is in primary metals.

Table 3.2 also reflects the high concentration of fuel use in a few key industrial sectors. Primary metals, chemicals, and petroleum refining consumed nearly 60 percent of scarce fuel used in the industrial sector in 1974.

3.4 PROJECTIONS OF 1985 INDUSTRIAL FOSSIL FUEL USE

3.4.1 Introduction

The MEFS model projects industrial demand for fossil fuels only for two sectors, petroleum refining and all other industrial uses. IFCAM analyzes fuel choice decisions for nine industrial sectors: food processing, textiles, paper, chemicals, petroleum refining, stone, clay and glass (SCG), steel, aluminum, and "other." The textile industry was selected by DOE staff and the other seven specific industries are major energy consumers. The eight specific industries selected account for about 80 percent of the oil and natural gas used in the industrial sector in 1974.

Analyzing industrial fossil fuel demand by these major industry subgroups adds an important element of realism to IFCAM. First, production growth rates differ significantly among industrial sectors. Since the economics of coal use are much more favorable for new combustors, those sectors with relatively high growth rates will tend to rely more on coal. Second, the

ratio of energy use in boilers compared to process heat uses varies significantly among industries (from 79 percent boiler use in food processing to 22 percent boiler use in steel). Since technical problems impeding coal and residual oil use are more severe in process heat energy uses than in boilers, industries in which boiler energy use is predominant will tend to utilize relatively more coal and oil. Third, even within the category of boiler fuel uses, boiler sizes and operating rates differ substantially between industries. For example, in food processing the boilers tend to be small and operate at relatively low capacity utilization rates, while the paper industry is characterized by large boilers operating at high capacity utilization rates. Other factors being equal, the tendency to select coal will be greater in paper manufacturing than in food processing since coal boiler economics are most attractive in large units with high operating rates. Fourth, the potential to use coal or oil also is substantially different among process heat uses between industrial sectors. SCG processes have significant coal potential while process heat operations in the chemical industry are not favorable for coal or oil use. By projecting fossil fuel demand for the nine industrial classifications, these factors can be weighted appropriately to reflect more accurately the overall industrial potential to consider coal or oil over gas.

3.4.2 Fossil Fuel Projections by Industry

Energy demand projections depend on rates of production growth, the introduction of new technologies (such as continuous casting in steel which reduces energy consumption per ton of steel processed), shifts in the product mix within any specific industry (as toward more highly processed, more energy-intensive frozen foods), fuel costs, opportunities to install energy recovery equipment, and capital available for energy saving measures. Business cycle fluctuations also affect energy consumption per unit of product, with energy efficiency declining in recession periods.

In the MEFS model, energy demand is driven by regional industrial output growth rates and fuel prices which are input into econometric equations based

on historical relationships. The MEFS model output includes oil, gas, and coal demand by region. The IFCAM model was specified to be consistent with the regional energy control totals generated by MEFS. In order to classify regional fossil fuel use by the nine industrial sectors used in IFCAM, the following steps were taken.*

- Regional industrial production growth rates for the nine sectors were taken from the same macroeconomic model output used in the MEFS run.
- The output growth rates were adjusted for an expected reduction in energy use per unit of output by industry (conservation effect).

The projected gains in energy efficiency are shown in the first column of Table 3.3. The overall gains in projected energy use per unit of product are conservative, reflecting somewhat lesser efficiency gains than historical trends (column 2). The industry-by-industry differences between projected and historical gains in energy efficiency are substantial, with more extreme highs and lows reflected in the past trends.

Table 3.4 shows the national aggregate output growth rates for the sample run and the conservation factors used to adjust energy demands. These resultant energy demand growth rates from column 3 of Table 3.4 were applied to 1974 energy use data by region and industry from the ECDB. This step adjusts the 1974 fuel use by industry for the relative product growth rates and conservation potential among the industries. Thus, for example, the fossil fuel demand in the chemical industry will tend to be a higher share of industrial demand in 1985 than it was in 1974 due to high expected growth and in spite of significant conservation gains expected in that industry.

Table 3.5 compares the MEFS fossil energy demand growth rates by region with the results of the simple projection technique discussed above. The simple

* Further details of all of the steps in this process are described in Appendix E.

TABLE 3.3 COMPARISON OF PROJECTED AND HISTORICAL ENERGY CONSERVATION
(annual rates of decline in energy use per unit of output)

<u>Industry</u>	<u>Projected 1975-85 (percent/year)</u>	<u>Historical 1954-1974 (percent/year)</u>
Food	0.5	2.3
Textiles	1.5	N/A
Paper	1.2	.5
Chemicals	1.6	3.0
Petroleum	0.7	1.2
SCG	1.7	1.1
Steel	1.7	} .3
Aluminum	1.7	
Industry Average	1.3	1.6

SOURCE: Energy Conservation in the Manufacturing Sector, 1954-1990, prepared by EEA for the Council on Environmental Quality, November, 1974. Additional details are available in Appendix E.

TABLE 3.4 INDUSTRIAL PRODUCTION GROWTH RATES
AND CONSERVATION FACTORS
1975-1985
(percentage rate of annual increase)

<u>Industry</u>	<u>Production Growth^{a/}</u>	<u>Conservation Effect^{b/}</u>	<u>Energy Growth Rate</u>
Food	3.6	-0.5	3.1
Textiles	3.7	-1.5	2.2
Paper	2.2	-1.2	1.0
Chemicals	5.0	-1.6	3.4
Petroleum	2.5	-0.7	1.8
SCG	3.2	-1.7	1.5
Steel	0.4	-1.7	-1.3
Aluminum	0.4	-1.7	-1.3
Industry Average	3.2	-1.3	1.9

a/ Growth in value added data in constant 1975 dollars. All industries except textiles, steel, and aluminum were taken directly from Data Resources, Inc., estimates. Textiles, steel, and aluminum were based on DRI and in-house estimates.

b/ Changes in rate of energy use per unit of output. Derived from Energy Conservation in the Manufacturing Sector, 1954-1990, prepared by EEA for Council on Environmental Quality, November, 1974. Additional details are available in Appendix E.

TABLE 3.5 COMPARISON OF MEFS REGIONAL INDUSTRIAL FOSSIL FUEL
DEMAND GROWTH WITH SIMPLE PROJECTION METHODS
(percent increase per year)

<u>Region</u>	<u>1975-1985 MEFS Annual Fossil Fuel Growth^{a/}</u>	<u>1975-1985 Projections - Production and Conservation Adjustments Only^{b/}</u>
1	-0.2	1.6
2	-1.8	3.1
3	-0.1	1.8
4	-0.5	2.5
5	0.9	1.1
6	5.9	2.1
7	-2.3	6.2
8	3.2	7.6
9	3.2	1.5
10	0.6	1.7
U.S.	2.6	2.4

^{a/} Sample run population (see Section 8). Includes steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

^{b/} Before reconciliation to MEFS totals.

projection method (column 3) forecasts total national growth to be very close to that suggested by the MEFS output. Significant differences exist in regions 2, 6, 7, and 8, but only region 6 has a large population. The MEFS growth rate in region 6 is almost 200 percent higher than the simple method's growth rate in region 6. Due to these large differences, the regional results should be interpreted carefully.

Energy demands projected in this fashion, independent of the MEFS model, are adjusted so that overall regional industrial demand is consistent with the MEFS control totals while retaining the projected mix of fuel use by industrial subsector. The resultant industrial fossil fuel demands are shown in Table 3.6, aggregated to a national level. The results of this first step significantly change the share of fossil fuels consumed by the industrial sector over the 1975-85 time frame. The rapidly growing chemical industry's share of consumed industrial fossil fuel rises from 18 to 25 percent. Steel's share, on the other hand, drops from 10.1 to 6.1 percent.

The final step taken in this stage of projecting energy demand is the removal of 1974 coal use (after retirement) totals from the 1985 fuel demand. It is assumed that units already burning coal will continue to do so and will not consider shifting to oil or gas. Only the fuel use that can be substituted by an alternative fuel is included in the demand for fossil fuels. 1974 coal use is derived from ECDB by region and industry. Table 3.7 shows the total of 1974 steam coal use by sector. In all, this amounts to about 1.4 quads of coal use in existing units in 1974, of which 1.08 quads are projected to remain, after retirements, in 1985. 1974 coal-fired combustors still in operation in 1985 will be included as part of coal's share of total fuel demand in the model's output stage.^{2/}

Fossil fuel demand for 1990 and 1995 is forecasted in the same way as for 1985; the only changes are different production growth and energy conservation rates.

TABLE 3.6 TOTAL FOSSIL FUEL DEMAND^{a/}

<u>Industry</u>	1975 Total Fossil Fuel ^{b/} (10 ¹² Btu's)	1985 Total Fossil Fuel ^{c/} (10 ¹² Btu's)	Compound Annual Increase (percent/year)
Food	682.3	880.3	2.3
Textiles	189.1	177.2	-0.6
Paper	1,183.0	1,236.0	0.4
Chemicals	2,210.4	4,126.1	5.8
Petroleum	2,491.6	3,294.5	2.6
SCG	1,025.4	1,230.6	1.7
Steel	1,231.4	984.4	-2.0
Aluminum	508.3	616.9	1.8
Other	2,700.2	3,685.9	2.9
Total	12,221.7	16,231.9	2.6

a/ Steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas. Excludes feedstocks and LPG.

b/ Source: Energy Consumption Data Base, prepared by EEA for FEA, June, 1977. Includes steam coal, distillate and residual fuel oil, natural gas, and refinery (still) gas.

c/ Sample run population (see Section 8). Includes steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

TABLE 3.7... 1974 INDUSTRIAL STEAM COAL USE BY INDUSTRY

<u>Industry</u>	<u>Coal Use</u> <u>(10⁶ MMBtu)</u>
Food	75.37
Textiles	24.30
Paper	224.96
Chemicals	307.47
Petroleum	7.20
SCG	184.18
Steel	285.20
Aluminum	73.20
Other	208.48
Total	1,390.96

SOURCE: Energy Consumption Data Base, prepared by
EEA for FEA, June, 1977.

FOOTNOTES

1. Energy and Environmental Analysis, Inc., "Energy Consumption Data Base," prepared for Federal Energy Administration, June 9, 1977.
2. These 1975 coal demands are later added back into the NGPM coal use projections to give total projected coal use in 1985. 1975 coal use is reduced at a rate of one percent per year to reflect retirements of old combustors. This retirement rate is assumed to be less than the normal retirement rate of oil- and gas-fired units, since the rise in the relative costs of oil and gas will provide incentives for industry to extend the useful lives of their existing coal-fired boilers. See Section 4 for a discussion of the derivation of retirement rates.

4. CHARACTERISTICS OF INDUSTRIAL FOSSIL FUEL USE

4.1 INTRODUCTION

In order to determine that portion of total projected industrial fuel consumption which may utilize alternative fuels, expected fossil fuel uses need to be identified according to characteristics which affect the costs and technical aspects of fuel substitution. One characteristic which affects the technical capability to use coal or oil is the type of combustor used. Technical issues related to fuel use differ, for example, among boilers, cement kilns, and tubestill heaters. Characteristics which affect the costs of using alternative fuels include combustor type, size, whether the combustor is a new or existing unit, and capacity utilization. Characteristics related to pollution control requirements which also affect the costs of using alternative fuels include combustor type, size, new/existing status, and location. Finally, many of the policy proposals to be evaluated by IFCAM target particular subcategories of industrial oil and gas demand. A disaggregated classification of fuel uses allows explicit consideration of taxes, investment incentives, regulations, and exemptions which vary in their impact on categories of industrial fuel use.

This section discusses those characteristics used to classify industrial fossil fuel uses and explains the methodology and data bases used in the disaggregation. The major classification steps performed sequentially for each industry in each region include:

- Classifying fuel use in new combustors, in existing combustors originally designed to fire coal, or in existing units designed to fire only oil or natural gas.
- Allocating fuel demands by functional use (i.e., type of combustor).
- Classifying fuel use by combustor size and capacity utilization.

- Allocating current natural gas and oil supplies among existing industrial uses.

4.2 CATEGORIZATION OF FOSSIL FUEL USE BY NEW AND EXISTING FACILITIES

4.2.1 Importance of New/Existing Distinction

This distinction is critical to any analysis of fuel choice decisions since the technical capability, the nature of the investment decision, and the costs of using alternate fuels differ for existing units (units existing in 1975 which still will consume fuel in 1985) compared to new facilities (units which come on line between 1975 and 1985).

Technical issues associated with coal use are typically far more severe for an existing combustor not originally designed to fire coal than for a new facility. For example, it is cheaper to replace an existing boiler designed only to fire gas with a new coal-fired boiler than to modify the gas-fired boiler to fire coal. It is possible to retrofit (or modify) some process heaters to fire coal, but technical problems generally are so severe that accelerated retirement of an existing scarce fuel-fired combustor and replacement with a new coal-fired combustor will be more economic than retrofit.

Due to varying technical problems associated with converting existing combustors to fire coal, the investment decisions and associated costs of fuel substitution differ among combustors. The following four classes of combustors each involve different technical problems, costs, and investment decisions.

- Existing coal-capable units: These combustors currently are firing oil or gas but originally were designed to use coal. Minor capital investment is needed to refurbish coal-related equipment already available in order to return to coal use. Pollution control equipment may be needed as well, depending on environmental regulations.

- Existing units designed to fire only oil and/or gas, can be retrofitted: For these combustors, it is cheaper to retrofit an existing unit to fire coal rather than to entirely replace the combustor with a new coal-fired unit. The elements of the investment decision for conversion to oil or gas are similar to those for the existing coal-capable combustor.
- Existing units designed to fire only oil and/or gas, cannot be retrofitted economically: For this class of combustors, it is more economic to replace an existing unit with a new coal-fired unit than to retrofit the facility. This accelerated replacement decision focuses on the full capital cost of a new coal-fired combustor and higher operating and maintenance costs of coal. Capital costs for continuing to fire oil or gas are sunk costs and therefore are assumed to be zero in the comparative economics calculations. Retrofit to oil or gas involves the same costs as the first two cases.
- New facilities: For new combustors, the costs of new units for each fuel type are compared, including total capital investments and operating fuel costs.

Many government policies and regulations recognize the differences in investment approach and costs between new and existing units. Because existing units are viewed as much more costly to convert to coal than new units, some energy policy proposals designed to encourage the use of coal over oil and gas have targeted only new units. For example, PIFUA exempts existing units with no coal firing capability from provisions mandating conversion of industrial boiler energy use from oil and gas to coal. The designation of fuel demands as either new or existing allows for more careful study of proposed policies as well as proper accounting for different investment decisions.

The model logic first distinguishes between fuel use in all existing versus new combustors in 1985. The distinction of fuel use among the first three classes of existing units is discussed in Section 6.

4.2.2 Approach to Allocation of Fuel Use Among New/Existing Facilities

Since projected fossil energy demand in any future year is an exogenous input to the IFCAM model, the split between energy use in new facilities (e.g.,

for a 1985 projection, facilities coming on line between 1975 and 1985) and existing facilities (e.g., units which existed in 1975 and which still will consume energy in 1985) will be determined by the exogenous growth rate in total fossil fuel demand plus the retirement rate of existing facilities.

In estimating the retirement of energy use in existing combustors, IFCAM distinguishes two retirement concepts: normal and accelerated retirement. Normal retirement reflects decreases in energy use due to physical deterioration and increased costs. It is important to emphasize that the concept of normal retirement does not consider that the economics of fuel use in existing combustors may be altered by fuel price trends or major energy policy measures. The second concept, accelerated retirement, reflects a possible speedup in the "normal" rate of decline of fuel use in existing units due to major shifts in fuel price or energy policy measures.

IFCAM initially makes the split between fuel use in new and existing combustors solely on the basis of the normal retirement concept. The model then explicitly estimates accelerated retirement of fuel use in existing combustors as a function of fuel prices and energy policy measures.

4.2.3 Determination of Normal Retirement Rates

Retirement of energy use in existing combustors can take place through reduced capacity utilization or actions which reduce fuel use to essentially zero, such as actual scrappage or a shift to standby status. Recent analysis of trends in capacity utilization (see Appendix F) and EEA's experience in industrial fuel use indicate that there is no systematic correlation between capacity utilization and combustor age. Consequently, this analysis defines retirement as scrapping or placing the unit on a standby availability status.

The decision to retire a combustor is determined by many parameters. Over time, equipment will deteriorate and require replacement. Maintenance costs

tend to increase and, depending on the type of combustor, fuel use efficiency (e.g., for a boiler, Btu's of fuel input per pound of steam generated) may decline. Essentially random factors, such as the phaseout of an uneconomic plant or part of an old plant's production, also can cause a combustor to retire. In addition, the technical fuel use efficiency and cost of new combustors will affect normal retirement rates. Fuel costs, conservation potential, the availability of capital, and other investment demands all influence retirement rates. Logically, the decision to replace combustors is a function of the economics of plant- and corporate-specific situations.

There are few useful studies of the empirical determinants of retirement rates.^{1/} The ideal set of data required to estimate retirement rates, such as the number of combustors installed in historical time periods, is not generally available. Thus, retirement rates must be determined crudely, based on judgment in the context of relevant studies.

A simple approach to estimating retirement rates for boilers would assume a 30-year normal life in light of an historical trend in manufacturing energy growth of three percent per annum (1954-1971).^{2/} If one assumes a constant three percent per annum growth rate, then the rate of retirement per year would be equivalent to two percent of each year's energy consumption levels. In fact, of course, the growth rate in energy combustion capacity is cyclical rather than constant, and useful life is not a constant 30 years for boilers but varies depending on the factors discussed earlier. For example, there was a surge in new investments during the World War II period as the economy geared to the war effort and many of these units currently are 30-35 years old; the retirement rate of the existing stock of combustors, therefore, should be higher than two percent per year.

In a previous study, EEA used the concept of vintaging plus decay factors to estimate retirement or capital turnover rates.^{3/} This approach indicated retirement rates (percent of annual energy use retired) in the range of two to three percent for boilers.

Using the simple approach described above, which yielded two percent per annum retirement rates, and adjusting this rate upward to allow for the cyclically high rate of manufacturing investments during the 1940's, IFCAM uses a retirement rate of 2.5 percent per year for boilers. This retirement rate appears to be in the range of estimates obtained in the EEA study using the vintaging approach.*

In determining even such "ballpark" replacement rates, it is important to distinguish among major industrial processes. Process combustor service lives vary substantially among industries and, to a lesser extent, within industries. For example, in the glass industry, regenerative furnaces have average useful lives of five to seven years; unit melters last only three to five years. Yet, in the steel industry, units used in some processes (e.g., blast furnace hydrocarbon injection and traveling grate pelletizers) last up to 50 years. The range of nonboiler service lives is so large between industries that retirement rates in this analysis are industry-specific. Table 4.1 displays the retirement rate used for each industry group.

4.2.4 Determination of Accelerated Retirement Rates

Once the normal retirement rate has been determined, IFCAM solves for the accelerated component by an investment decision analysis. This investment decision focuses on replacing the existing unit firing scarce fuels with a new coal-fired combustor to minimize the present value of energy costs. The focus is only on coal since a decision to replace an existing gas-fired combustor with a new oil/gas-fired combustor generally would not be more expensive than retrofitting the existing unit. This investment decision is in the conventional form of comparing capital, operating, and fuel costs for a new coal-fired unit with similar retrofit costs for oil and gas units. Details of this analysis are presented as part of the general investment

* The 2.5 percent retirement rate for boilers is equivalent to a 40-year useful life for stable capital stock.

TABLE 4.1 NORMAL RETIREMENT RATES FOR PROCESS HEAT USES
(percent of annual energy use retired)

<u>Industry</u>	<u>Retirement Rate</u>
Food	4.7
Textiles	4.2
Paper	3.4
Chemicals	2.0
Petroleum	1.9
Stone, Clay and Glass	4.0
Steel	1.7
Aluminum	3.9
Other	3.6

SOURCE: Retirement rates were derived by taking the normal service life of the major process heat uses in each industry sector and using the reciprocal of that useful life as the annual replacement rate.

decision analysis of fuel choice which appears in Section 7 of this report.

4.2.5 Caveats and Issues

There should be no pretensions that normal retirement rates used in IFCAM are based on anything but reasonable judgments in the context of limited available data and related studies. The analysis of retirement rates, nonetheless, is important because it makes the following critical distinctions:

- Accelerated retirement as a consequence of shifts in fuel price or energy policy measures is analyzed separately from normal retirement.
- Major distinctions in normal retirement rates between certain process uses are made to insure that short-lived processes experience a much higher capital turnover rate than long-lived equipment.

There is no question that the normal retirement rate is a critical element in fuel choice decisions since the technical issues and associated economics tend to strongly discourage coal use in existing combustors not originally designed to fire coal. There is a bias against retrofitting from one fuel to another since no capital investment is necessary to continue to fire the existing fuel. The retirement rates used in IFCAM are reasonable, but further work with a solid empirical base clearly needs to be performed on this topic.

One factor worth emphasizing is that EEA's approach to estimating retirement rates does not consider the effect of rising fuel costs or energy policy on the overall efficiency of energy use in existing combustors. For example, taxes on fuel use affecting existing combustors will conserve energy; this energy conservation, however, will not be captured by retirement rates based on historical trends. The failure of IFCAM to consider the impact of energy policy or fuel prices on overall energy efficiency in existing units will tend to bias fuel mix results away from coal. This bias occurs because the projected year fossil energy demand (exogenous to IFCAM)

does include the effect of higher fuel prices, for example, on overall fuel use efficiency. Since IFCAM ignores this conservation effect in determining normal retirement rates, conservation benefits come entirely out of fuel use in new combustors. This can be seen in Table 4.2 by comparing two scenarios of fossil fuel demand input to IFCAM. In the base case scenario, adjustment for normal retirements results in fuel use of 70 units in existing combustors and 80 units in new combustors, a total demand of 150 units. In scenario 2, higher fuel prices or conservation policy estimates reduce aggregate fossil fuel demand from 150 to 140 units. Since normal retirements are not adjusted to capture this conservation effect, all the conservation implicitly takes place in new combustors. Since coal use is relatively more economic in new units, this approach tends to understate the estimate of coal use generated by IFCAM in scenarios with higher fuel prices or conservation policy measures.

4.3 CATEGORIZATION OF FOSSIL FUELS BY FUNCTIONAL USE

4.3.1 Approach

Classifying fossil fuels by functional use is critical because the technical and economic issues of fuel substitution vary according to specific process applications. To categorize fossil fuels by functional use, projected energy consumption for each region and industry first is split into two functional use classes: boilers and process heaters. Boilers use fossil fuels to produce process steam and internally generated electricity. Boilers consume more oil and gas than any other single industrial consumption process. Process heat applications include furnaces, ovens, kilns, and heaters and exclude all boiler and feedstock uses. Oil and gas use in process heaters comprises 58 percent of total industrial non-feedstock oil and gas use.^{4/}

Although types of boilers (combustor size and capacity utilization) vary among industrial sectors, issues related to costs or the technical capability

TABLE 4.2 ILLUSTRATION OF BIAS INTRODUCED
BY ENERGY CONSERVATION POLICIES

	Scenario 1: <u>Base Case</u>	Scenario 2: Higher Fuel Prices or Conservation <u>Policy Measures</u>
Fuel use in existing combustors in 1975	100	100
Less normal retirements	<u>30</u>	<u>30</u>
Fuel use in existing combustors in projection year	70	70
Total projected fossil fuel use in projection year	150	140
Fuel use in projection year in:		
- existing combustors	70	70
- new combustors	<u>80</u>	<u>70</u>
- all combustors	150	140

to utilize alternative fuels are generic for each boiler of the same size operating at the same capacity utilization rate. Process heaters, however, must be evaluated according to specific applications since costs and technical problems differ, for example, among tubestill heaters used in crude distillation in petroleum refining, tubestill heaters used in catalytic cracking in petroleum refining, and reheat furnaces used in the manufacture of steel and nonferrous metals. Consequently, fossil fuel demand must be classified by functional use in two steps. First, fuel use is split between boilers and process heaters. Second, within each industry, fossil fuel use is classified into major process heat uses.

4.3.2 Allocation of Projected Fossil Fuel Use among Boiler and Nonboiler Categories by Industry

For each region and industry, projected total fossil fuel consumption is split between two classes: boilers and process heaters. The breakdown is based on 1974 data from the ECDB. Table 4.3 shows functional use shares for oil and gas by industry. Currently, coal is used primarily in boilers, with cement kilns being the primary exception. For most of the industries shown, the difference in boiler/nonboiler splits between oil and gas use is slight. When differences exist, there are no obvious technical or economic reasons for the particular industry to prefer oil to gas, or vice versa. The discrepancies between the functional use splits for each fuel are smaller than the level of probable error associated with ECDB functional use data. Consequently, the split between the two major functional uses is based on the sum of historical coal, oil, and gas consumption in each industry. The focus on total fossil fuels, rather than on coal, oil, and gas separately, seems warranted since the ratio of coal to oil to gas in the future is expected to differ substantially from historical patterns. Consequently, the classification by functional use and new/existing combustors is made first only for total fossil scarce fuels, leaving the specific allocation of fossil fuel demands by fuel type to a later step in the classification process.

TABLE 4.3 FUNCTIONAL USES OF OIL AND GAS BY INDUSTRY
(1974)

<u>Industry</u>	<u>Percentage Use by Fuel Type</u>			
	<u>Oil</u>		<u>Gas</u>	
	<u>Boiler^{a/}</u>	<u>Process Heat^{b/}</u>	<u>Boiler</u>	<u>Process Heat</u>
Food	80	20	79	21
Textiles	100	0	73	27
Paper	86	14	42	58
Chemicals	65	35	69	31
Petroleum	14	86	25	75
Stone, Clay and Glass	4	96	3	97
Steel	15	85	25	75
Aluminum	14	86	49	51
Other	NA	NA	NA	NA

a/ Process steam and self-generated electricity classified as boiler.

b/ Direct heat category classified as process heat.

SOURCE: Energy Consumption Data Base.

National functional use shares for fossil fuels by industry are shown in Table 4.4. Based on fuel use, major industry groups generally can be broken down into predominantly boiler or nonboiler industries. Boiler industries are food, textiles, paper, and chemicals, while nonboiler industries are petroleum, SCG, and steel. Aluminum and "other" industries use approximately an equal mix of boiler and process heat fuel.

The boiler industries can be classified further as industries using small boilers (e.g., food and textiles) or industries using large boilers (e.g., paper and chemical manufacturing). In the food industry, steam is used primarily for washing and sterilizing containers, cooking, evaporating, space heating, and electricity generation. The textile industry relies heavily on purchased electricity to drive the machinery in the plants; fuel oil and natural gas are used predominantly in boilers. In this industry, steam also is used for fabric preparation, dyeing, and finishing operations as well as space heating. Very little electricity is generated in textile mills.

The large-boiler industries, paper and chemical manufacturing, use a significant portion of process steam to generate electricity. In chemical manufacturing, steam demand is used to strip away unreacted feed, as dilution steam, and to drive steam compressors. The process fuel uses are primarily in cracking furnaces. Process steam in the paper industry is used to generate electricity and in the pulping and bleaching processes. Some systems also use steam in debarking.

Process uses of scarce fuels in the petroleum industry are in tubestill heaters or furnaces. In steel, blast furnaces, soaking pits, reheat furnaces, and heat treating applications are the primary process uses. SCG fuel use is dominated by cement which uses process heat in cement kilns. Glass production makes up the other significant portion of SCG, with glass furnaces as the primary energy use.

TABLE 4.4 BREAKDOWN OF FOSSIL FUELS BETWEEN
BOILER AND PROCESS HEAT USES

(% of fossil fuel use)

<u>Industry</u>	<u>Boiler</u>	<u>Process Heat</u>
Food	79	21
Textiles	83	17
Paper	68	32
Chemicals	69	31
Petroleum	25	75
Stone, Clay and Glass	4	96
Steel	22	78
Aluminum	52	48
Other	50	50

Aluminum is a large electricity producer and the bulk of the boiler use in that industry is consumed to self-generate electricity. The rest of the fuel, roughly half, is consumed in direct heat applications. "Other industry" is a conglomeration of the manufacturing industries not explicitly covered, with construction, mining, and agriculture users included. The boiler/nonboiler mix for these "other" sectors was estimated, not in the ECDB, but from the boiler/nonboiler mix of the specific industries covered in that data base. Since fuel use in small industries resembles fuel use in industries such as textiles and food, these two industries were weighted more heavily than others in deriving the boiler/process heat fuel shares for miscellaneous industrial energy uses.

4.3.3 Allocation of Nonboiler Fuel Use among Processes

Fossil fuel use in process heat applications for each region and industry includes fuel consumed in many distinct processes. The share of fossil fuels consumed by each type of process within an industry group was derived from a recent study of industrial energy use.^{5/} These shares essentially reflect current energy use by process. No systematic effort was made to project carefully changes in the relative shares of fossil fuels among process applications within all industries. The historical shares generally were assumed to hold for both new and existing facilities in all regions for each industry. Table 4.5 lists as an illustration the principal process heat uses in the petroleum refining industry and the percentage of total scarce fuel each use consumed in 1974.

These shares of fuel consumption use were adjusted roughly to account for major trends which shift the process mix for three industries: petroleum refining, steel, and aluminum. In petroleum refining and steel, two processes currently using oil and gas (thermal cracking and open hearth smelting) are not expected to be installed in any new facility. This trend was accounted for by setting scarce fuel uses in these two processes equal to zero for new facilities only and normalizing the remaining process use

TABLE 4.5 OIL AND GASEOUS FUEL CONSUMPTION IN DIRECT HEAT
PROCESS APPLICATIONS IN THE PETROLEUM REFINING INDUSTRY
(1974 data)

<u>Process</u>	<u>Scarce Fuel Consumption (% of total fuel use)</u>
Catalytic reforming	21
Atmospheric crude distillation	20
Alkylation	10
Hydrocracking	10
Hydrotreating	7
Vacuum distillation	7
Hydrorefining	4
Hydrogen manufacture	3
Delayed coking	2
Visbreaking	1
Thermal cracking	2
Other processes	-
Not accounted for	13

SOURCE: Energy and Environmental Analysis, Inc., "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report, prepared for DOE, May 22, 1978, p. VIII-7.

shares to equal 100 percent. Adjustments also were necessary due to differences in the shares of fuel use by process and region for steel and aluminum, industries in which certain processes are located only in a few regions. For example, 75 percent of the primary steel industry is located in the Great Lakes region close to major deposits of iron ore and supplies of coking coal. In these regions, scarce fuels are used in integrated steel mills. Outside these regions, the process mix was adjusted to reflect the absence of consumption in beneficiation, blast furnaces, and steel-making furnaces. Table 4.6 illustrates the resultant impact on the process mix for steel.

The final result of this characterization of fossil fuel by type of combustor and new/existing facilities is illustrated in Table 4.7 for the petroleum refining industry in the total U.S. The table shows how the 3294×10^6 MMBtu's of fossil fuel use* in 1985 have been allocated among the 13 combustor types in the industry for both new and existing combustors.

4.3.4 Problems and Biases

The major weakness of this method of allocating scarce fuel consumption by functional use among combustor types is that it relies on historical patterns except in clear cases where differences in process mix by region or for new/existing facilities are critical. While a careful study of the future shifts in the relative importance of various industrial processes would improve the accuracy of forecasts, the current approach does not introduce any clear bias for or against any fuel. Since the industrial process mix within industries shifts slowly over time, the approach employed should accurately reflect key shifts in relative energy use between industries and the volume of energy used in new versus existing facilities.

* Including steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

TABLE 4.6 SCARCE FUEL USE BY MAJOR PROCESS FOR THE
IRON AND STEEL INDUSTRY
(percent of scarce fuel use in the region)

<u>Process</u>	<u>Regions with Integrated Steel Production^{a/}</u>	<u>Regions without Integrated Steel Production^{b/}</u>
Pelletizing shaft furnace	4	0
Pelletizing traveling grate furnace	6	0
Pelletizing grate kiln	6	0
Sinter strand	3	0
Blast furnace stove	9	0
Blast furnace hydrocarbon injection	37	0
Soaking pits	4	0
Reheat furnace	25	81
Annealing and other finishing furnaces	<u>6</u>	<u>19</u>
	100	100

^{a/} Regions include Mid-Atlantic, Midwest.

^{b/} Regions include all others.

TABLE 4.7 ILLUSTRATION OF FUEL DEMAND BY NEW/EXISTING
FACILITIES AND BY COMBUSTOR TYPE
(10⁶ MMBtu in 1985)

Industry: Petroleum Refining

Region: Total U.S.

<u>Process</u>	<u>Existing Combustors</u>	<u>New Combustors</u>	<u>All Combustors</u>
Boilers	228.8	593.2	822.0
Catalytic reforming	162.7	351.0	513.7
Atmospheric crude distillation	151.9	327.8	497.7
Alkylation	75.3	162.5	237.8
Hydrocracking	73.2	157.9	231.1
Hydrotreating	57.2	123.5	180.7
Vacuum Distillation	56.8	122.6	179.4
Hydrotreating	34.9	75.2	110.1
Hydrogen manufacture	25.8	55.7	81.5
Delayed coking	19.4	41.8	61.2
Visbreaking	6.5	13.9	20.4
Thermal cracking	17.2	-	17.2
Other processes	1.7	3.7	5.4
Not accounted for	95.5	258.8	354.3
Total	778.1	1678.9	3294.5

SOURCE: Boiler and process heat fuel totals were derived from model intermediate output, based on fuel totals for the sample run (see Section 8). Process heat energy distribution is from Table 4.5.

4.4 CLASSIFICATION OF FUEL USE BY SIZE, CAPACITY UTILIZATION, AND USEFUL LIFE

4.4.1 Importance

The size, capacity utilization, and useful life of a combustor greatly affect fuel choice decisions. Combustor size is important for several reasons. First, the economics of fuel choice decisions are sensitive to size since the costs of fuel use tend to be characterized by scale economies. Second, pollution control strategies, often involving substantial capital and operating costs, can depend on size. Environmental regulations, both state and federal, specify levels of some types of air pollution control according to combustor size. In addition, recent federal energy tax, investment incentive, and regulatory proposals have targeted industrial combustors above specified sizes. To capture the policy implications of combustor size considerations, projected scarce fuel demand was further disaggregated among broad size categories.

The capacity utilization of a combustor also is a critical parameter in the economics of fuel choice decisions. Capacity utilization rate represents the total number of Btu's actually burned in a combustor during a year divided by the maximum number of Btu's that could be burned, assuming a fixed firing rate and 8760 hours per year of operation. The higher the capacity utilization rate, the more coal is likely to be the least cost fuel choice since there will be more fuel cost savings to offset the relatively higher capital costs associated with coal use.

Remaining useful life has a similar impact on the economics of fuel choice as does capacity utilization. The longer the useful life, the more likely it is that fuel savings will offset the capital costs of using coal.

4.4.2 Combustor Size

Fuel use was allocated into four size classes for boilers and a variety of sizes appropriate to specific process heat uses. Distribution of fuel use

by size was treated differently for boilers and process heaters and for new versus existing combustors.

4.4.2.1 Boilers

Boiler size distributions for new installations were based solely on data collected by the American Boiler Manufacturers Association (ABMA). Because ABMA data reflect industries' investment decisions of the last 12 years (1965-1977) and any recent trends in the characteristics of industrial boiler investments, they are preferred over data bases which essentially are inventories of the existing boiler population, reflecting decisions made up to 50 years ago. For each industry, a national distribution of total scarce fuel use in new boilers among four size categories was developed: 0-25 MMBtu/hr, 25-100 MMBtu/hr, 100-250 MMBtu/hr, and greater than 250 MMBtu/hr. Table 4.8 lists the percentage distributions of capacity among these size classes for each industry.* The size distributions were assumed to be the same for new boilers regardless of fuel firing capability.

Fuel consumed in existing units was classified into three size categories. For units above 100 MMBtu/hr capacity, scarce fuels were allocated among two classes using data from the Major Fuel Burning Installation (MFBI) survey: 100-250 MMBtu/hr and greater than 250 MMBtu/hr. Fuel consumption in existing boilers below a 100 MMBtu/hr firing rate was not covered in the MFBI survey. Fuel consumed in this third class of boilers was assumed to reflect the trends indicated by the ABMA data shown in Table 4.8.

4.4.2.2 Process Heaters

There are no comparable data sources available to determine the distribution of fuel use by size in process heat applications. A systematic collection of such data was beyond the scope of this effort; consequently,

* Fuel distributions are actually a function of both size and capacity utilization. However, the basic data elements are discussed separately for presentation purposes.

TABLE 4.8 1985 SCARCE FUEL DISTRIBUTION IN NEW BOILERS BY INDUSTRY
(percent)

<u>Industry</u>	<u><25 MMBtu/hr</u>	<u>25-100 MMBtu/hr</u>	<u>100-250 MMBtu/hr</u>	<u>>250 MMBtu/hr</u>	<u>Total</u>
Food	12	37	44	7	100
Textiles	6	69	24	1	100
Paper	1	11	26	62	100
Chemicals	1	24	46	29	100
Petroleum	0	17	42	41	100
SCG	20	60	20	0	100
Steel	1	37	57	5	100
Aluminum	0	17	57	26	100
Other	8	38	47	7	100

SOURCE: American Boiler Manufacturers Association historical data.

distribution of fuel use by combustor size was based on judgments by EEA staff familiar with these industries and on comments provided by industry representatives. The MFBI data contain size data for large process heaters, but because process definitions were so difficult to relate to the MFBI questionnaire responses and a much larger share of process heat fuel use is in units below 100 MMBtu/hr, the MFBI data were not used. The size distribution for process heaters was assumed to be the same for new and existing combustors. Size classes for each process are presented in Appendix G.

4.4.3 Capacity Utilization

The capacity utilization rate of combustors is a key factor considered in determining the economics of investment decisions. IFCAM in its present form can accept any distribution of capacity utilizations as a function of industry, combustor type, size, and new/existing status. However, several consistency problems exist with current and historical sources of capacity utilizations and there is not sufficient knowledge of the factors that drive capacity utilization rates to develop a definitive distribution. The current distribution in the model reflects historical data subjectively adjusted for obvious discrepancies (capacity utilization over 100 percent) and in-house industry knowledge.

The first part of this section discusses the basic factors that influence capacity utilization and the work being done to develop a better understanding of those factors. The second part discusses the approach EEA used in developing capacity utilization distributions, why it was taken, and what biases were created.

4.4.3.1 Factors That Influence Capacity Utilization

If no other factors were important, capacity utilization rates would be set to maximize fuel use efficiency in each specific combustor. However, plant steam load characteristics (daily and seasonal fluctuations) will vary,

affecting the rates of capacity utilization. Boilers firing more expensive fuels will tend to be utilized less than low cost alternatives in a plant. Boilers generating process steam are run at higher load factors than space heat boilers. The following is a partial list of factors that might affect capacity utilization rates for each combustor:

- Industry group.
- Functional use.
- New/existing distinction.
- Size.
- Age.
- Fuel type/price.
- Plant capacity in relation to annual steam demand.

Work is being done with the major data bases (MFBI, NEDS, and Census Survey of Plant Capacity) to determine the important factors that correlate with capacity.

Preliminary results from regression analyses of the MFBI file substantiate that industry detail and functional use are important determinants of capacity utilization rates. The new/existing status was not tested since MFBI data solely cover existing combustors; the preliminary analysis on age, however, showed little correlation with capacity utilization. Size and fuel type seemed to correlate with capacity utilization, but further work is necessary to determine the extent of this correlation. A more detailed discussion of the derivation of capacity utilization rates and preliminary statistical results is presented in Appendix F.

4.4.3.2 Approach

During the initial development of the model, no regression analysis on the determinants of capacity utilization had been done; in fact, only preliminary MFBI data were available to develop historical distributions. The result was that distributions were developed separately for three combustor classes: existing boilers, new boilers, and process heaters and were based

on preliminary historical MFBI data and a good deal of subjective judgment. A discussion of nonboiler capacity distribution will be presented at the end of this section.

Just as for boiler size distributions, the distribution of boiler fuel use by capacity utilization rate was determined separately for new and existing installations. MFBI was used as the basis for the distribution among existing boilers. Distribution of capacity utilization among new boilers also was based on MFBI data but included adjustments when there were significant conflicts with Bureau of Census plant capacity data and when engineering judgments based on steam applications for each industry indicated significantly different distributions.

Capacity utilizations for large existing boilers with a firing rate of 100 MMBtu/hr or greater were derived from historical MFBI data. To facilitate computer handling of these data, five capacity utilization rates were recognized. Units with rates between zero and 30 percent were assigned to the 25 percent capacity utilization category; those between 30 and 50 percent were given a utilization rate of 45 percent. Units with rates between 50 and 60 percent were designated at 55 percent; those between 60 and 70 percent were assigned a 65 percent capacity utilization rate, and those above 70 percent were given a capacity utilization rate of 75 percent.

For smaller existing boilers, those firing at a rate less than 100 MMBtu/hr, no similar data exist. Units in this size category perform a wide range of functions, from space heat generation, generally considered to be a low utilization use, to process steam production, in which capacity utilization may reach 90 percent or more. For these reasons, a single middle estimate of 55 percent capacity utilization was used.

Use of a discrete distribution of capacity utilization was not felt to bias the results considerably. For large units, which are more likely to substitute fuels than smaller units, the choice of several capacity utilization

rates provides a fairly accurate measure of the actual utilization rate. For smaller units, the predominance of non-fuel costs in any retrofit investment decision will allow little conversion. If programs which specifically target the existing market are proposed, then further disaggregation will be necessary.

Capacity utilization rates for new boilers should vary by industry and size, potentially creating 54 different new boiler energy cells with varying capacity utilization rates. A unique distribution was developed for each size class within each industry based on historical data (MFBI) adjusted by in-house knowledge. Three steps were involved in the development of each distribution. First, the MFBI file was examined by industry and size category and first-cut distributions were developed. Second, these distributions were compared with Bureau of Census plant operation data on the number of shifts employed by each industry. Wherever there were significant discrepancies between the Census and MFBI data, the MFBI data were altered toward the Census data. Such adjustments usually were not necessary and were minor when required. Third, adjustments were made based on the actual steam applications in various industries. Some industries, for example, use a significant portion of their total steam production for space heating. Because space heating is only required a few months of the year in many parts of the country, the capacity utilization assumed for such needs was 25 percent. Other industries which use steam for power generation are known to operate around the clock, year round. MFBI distributions of capacity utilization for each industry and size class were examined to insure that they were consistent with these practical considerations. Refer to Appendix F for a more detailed discussion of the capacity utilization distribution and preliminary comparison with regression analyses results.

Very little data exist on capacity utilization rates of process heat uses; consequently, a single capacity utilization rate was assumed for each specific process. These load factors were subjective estimates based

primarily on in-house industry knowledge. In general, load factors for process heaters tend to be systematically higher than for boilers. Appendix G provides capacity utilization rates detailed by process.

4.4.3.3 Summary and Caveats

The resulting distributions of capacity utilization in new boilers are illustrated in Table 4.9 for the food processing and petroleum refining industries. The presentation of these two industries illustrates the difference in industries characterized by different boiler sizes and load conditions. Twelve percent of the total oil and gas use in the food processing industry is in units below 25 MMBtu/hr, while less than one percent of petroleum oil and gas use is consumed in those small units. These industries also illustrate that capacity utilization varies by size class in each industry. Most of the fuel use in the food processing industry is consumed in units between 25 and 250 MMBtu/hr at 45 percent capacity utilization. In contrast, petroleum refining is a highly energy-intensive industry with energy use concentrated in the large sizes (over 100 MMBtu/hr) and higher capacity utilization rates (75 percent).

Table 4.10 summarizes the national distribution of fossil fuel use in new boilers based on the sample run energy projections. The methodology used for both new and existing boilers implicitly assumes that the capacity utilization rate and size of coal boilers will not differ significantly from the oil and gas boilers they replace. The projections do not, for example, reflect that a higher capacity utilization rate is likely to be experienced if a given size boiler used coal instead of oil. Boiler economics, substantiated by preliminary statistical analyses of the MFBI data, suggest that boilers firing the cheapest fuels tend to be used more intensely. The failure to account for possible trends toward larger boilers and higher capacity utilization rates, however, will tend to overstate the costs of capital intensive fuel options. Since the model will not reflect any trend toward larger and higher capacity utilization rates when coal is selected, the data used will tend to understate coal use.

TABLE 4.9: SAMPLE DISTRIBUTION OF NEW BOILER CAPACITY UTILIZATIONS,
BY SIZE, FOR TWO INDUSTRIES

<u>Industry</u>	<u>Size (MMBtu/hr)</u>	<u>Capacity Utilizations Used (%)</u>	<u>% of Total Industry Boiler Fuel Use Allocated to Size/ Cap. Util. Class</u>
Food processing	<25	55	12
	25-100	25	1
		45	36
	100-250	25	5
		45	39
	>250	45	4
		65	3
Petroleum refining	<25	55	-- a/
	25-100	45	7
		65	10
	100-250	75	42
		--	--
	>250	75	41
		--	--

a/ Less than one percent.

TABLE 4.10 DISTRIBUTION OF FOSSIL FUEL USE IN NEW BOILERS
BY CAPACITY UTILIZATION RATE

<u>Capacity Utilization Rate</u> <u>(percent)</u>	<u>% of Total Fuel Use</u>
0-29	8
30-49	11
50-59	28
60-69	43
70-100	<u>10</u>
	100

As noted previously, the model's other two major weaknesses are the unimodal distributions used for capacity utilization in existing small boilers and the lack of solid data for nonboilers. Although the direction of this bias is unclear, these segments represent a small portion of the total coal potential and will not affect the results significantly. Further work currently is underway to check these data and improve their quality.

4.4.4 Useful Lives of Equipment

4.4.4.1 Introduction

This section summarizes the assumptions in IFCAM with respect to the useful lives of equipment. The decision criterion in this model is to minimize the cash outflows for operating and capital costs over the remaining useful life of the unit. Therefore, the significance of the useful lives of equipment is to estimate the number of years of operating and fuel expenses to discount and add in the NPV calculation. The key parameters in this analysis are:

- New or existing combustor.
- Boiler or specific process heater.

Issues related to these variables and estimates of the parameters are included in this section.

4.4.4.2 Issues

In IFCAM, the remaining useful life is estimated for each combustor type (new or existing, boiler or specific process heater). In general, distributions of expected remaining lives are not available and averages are estimated. In reality, useful lives may vary by fuel type, size, or manufacturer and a single estimate may be misleading.

4.4.4.3 Approach

The general procedure for estimating remaining useful lives was different for boilers than for process heaters. The MFBI file contains data on the

year boilers greater than 100 MMBtu/hr were installed. This distribution was used to estimate the remaining useful lives of existing large boilers with retrofit coal potential. However, it was assumed that remaining useful lives do not exceed 10 years. This assumption was made because retrofit investments typically require a shorter payback period than do new unit investments. The existing population of boilers thus was grouped into two vintages, with remaining useful life estimated at five or 10 years based on reported date of installation.

New and early replacement boilers were assumed to have a useful life of 30 years. This estimate was verified by discussions with boiler manufacturers. Shorter lives for package boilers were not assumed because data on the MFBI file showed that a significant number of package (100-250 MMBtu/hr) boilers were 20-30 years old. All auxiliary equipment (e.g., pollution control, fuel handling) was assumed to have the same remaining life as boiler equipment.

Nonboiler remaining lives were process-specific and were obtained from discussions with equipment vendors. Appendix G summarizes these useful lives by process.

4.5 ALLOCATING FUEL DEMANDS BETWEEN GAS AND OIL IN EXISTING COMBUSTORS

4.5.1 Introduction

The previous steps have classified fuel use for each region and industry by functional use, new versus existing combustors, size, and capacity utilization. The sum of this fuel use, which is equal to control totals provided by MEFS, must be allocated by fuel type. New units' fuel use is determined by the investment decision in the model; existing coal use is assumed to remain coal in the future. Existing non-coal fuel use initially must be allocated among gas, residual oil, and distillate oil. This allocation is necessary to determine the current fuel type in retrofit decisions

for substituting one fuel with another. For example, if a combustor currently is firing oil, equipment required for oil fuel handling and storage already will be in place. For a unit currently firing only gas, the above equipment must be installed prior to conversion to oil firing capability. When possible, this allocation is determined by actual fuel use in the combustor; when such data are not available, other methods of allocation are used. To define these different methods, three types of combustors are examined: large existing boilers, small existing boilers, and existing process heat uses.

4.5.2 Fuel Type for Large Existing Boilers

Oil and gas use in boilers with a firing rate greater than 100 MMBtu/hr are derived directly from MFBI data which detail the fuel use capability of each boiler. Units burning oil or gas in 1974 were assumed to continue to do so until a decision to retrofit to an alternative fuel is made in the model.

4.5.3 Fuel Type for Small Existing Boilers

Explicit, disaggregated data on fuel use in boilers with a firing rate of less than 100 MMBtu/hr generally are not available. To determine distributions of fuel use by fuel type, region, and industry, ECDB data were used. Oil and gas totals from the ECDB were reduced by fuel use accounted for by combustors covered by the MFBI file; ECDB fuel use already had been separated by functional use (see Section 4.3). The resulting distribution of natural gas, distillate oil, and residual oil fuel use is applied to boiler fuel use totals not yet allocated.

The potential for bias in this method depends on two factors: the accuracy of the ECDB data and the completeness of the MFBI file coverage of large boilers (see Appendices A and B for further details). Large boilers not captured in the MFBI file will be placed in a smaller size category (fuel use for a 100 MMBtu/hr boiler not covered by MFBI data might be assumed to be divided among two 50 MMBtu/hr units).

4.5.4 Fuel Type for Existing Process Heat Applications

Explicit data are not available on fuel use in process heat applications. In addition, unlike boilers which can be designed to fire gas, oil, or coal, some processes must, for technical reasons, burn gas, while others are restricted to gas and distillate oil. The former processes must be given priority in the allocation of scarce gas supplies.

To account for these priority uses of gas in existing process heaters, an allocation scheme was developed. For each process heat application, an in-house estimate was made determining what percent of the fuel used in that process had to be gas. For some processes, such as blast furnaces, no gas use is required; other processes, such as pyrolytic furnaces in the chemical industry, are believed to use only gas in existing units.

Total gas use, by region and industry, was computed by applying ECDB fuel use distributions to MEFS control totals. For each region, the gas total is allocated among processes, giving priority to those who can only use gas. If any gas remains after this allocation, it is distributed among the lower priority users in proportion to total fuel use by process. The remaining fuel use of these other processes is allocated to residual and distillate fuel oil; Allocation of residual oil is limited only to those processes where its use is technically feasible.

4.5.5 Results of Fuel Allocation in Existing Combustors

Table 4.11 presents fuel use detail for existing units in 1985, broken down by functional use, region, and fuel type. Note the relative amounts of residual and distillate oils allocated to boilers and process heat applications. While more residual than distillate oil is allocated in boilers, the reverse is allocated in process heat applications. This reversal reflects the fact that relatively little residual oil presently is used in these processes, either due to technical constraints or the ready availability of natural gas in the past.

TABLE 4.11 FUEL USE IN EXISTING UNITS IN 1985^{a/}
(10⁶ MMBtu)

<u>Region</u>	<u>Boilers</u>			<u>Process Heat Uses</u>		
	<u>Gas</u>	<u>Residual</u>	<u>Distillate</u>	<u>Gas</u>	<u>Residual</u>	<u>Distillate</u>
1	15.19	95.68	12.73	32.14	20.61	25.43
2	29.36	103.84	40.19	86.46	27.42	44.13
3	94.61	109.40	62.78	210.29	46.51	24.36
4	249.17	210.27	132.59	214.13	50.65	123.07
5	315.21	95.64	29.37	376.22	61.44	165.63
6	796.95	67.20	9.63	398.67	11.41	66.90
7	175.17	15.59	24.98	159.56	4.43	14.23
8	100.36	33.54	47.86	70.73	2.84	97.06
9	190.65	20.62	33.59	101.25	6.69	51.01
10	90.59	27.21	22.83	52.01	6.58	30.18
U.S. ^{b/}	2057.27	778.99	416.55	1701.47	238.58	642.00

a/ This table was based on fuel use control totals used in the sample run (see Section 8) and applies to units existing in 1974 which will not be retired by 1985.

b/ Totals may not be exact due to rounding.

FOOTNOTES

1. Rowley, J. and Trivedi, P., Econometrics of Investment, John Wiley and Sons, New York, 1975; Feldstein, M.S., and Rothschild, M., "Towards an Economic Survey of Replacement Investment," Econometric 42, May, 1974, pp. 393-423; and Nickell, S., "A Closer Look at Replacement Investment," Journal of Economic Theory 10, 1975, pp. 54-88.
2. Energy and Environmental Analysis, Inc., Energy Conservation in the Manufacturing Sector, 1954-1990, prepared for the Council on Environmental Quality, November, 1974.
3. Energy and Environmental Analysis, Inc., "Industrial Sector Technology Use Model: Industrial Energy Use in the United States, 1974-2000," prepared for Department of Energy, April 28, 1978.
4. See Section 3 for a description of industrial fuel uses.
5. Energy and Environmental Analysis, Inc., "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report, prepared for Department of Energy, May 22, 1978.

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5. TECHNICAL AND OTHER CONSTRAINTS TO FUEL SUBSTITUTION

5.1 INTRODUCTION

Sections 3 and 4 describe how industrial demand for coal, oil, and gas was classified by industry, new/existing combustor, functional use (combustor type), size, capacity utilization, and remaining useful life. In this section, industrial fuel demand is screened to identify fuel choice options which clearly cannot occur due to technical constraints, timing considerations, or broad economic factors. For any investment decision, only those fuels not affected by constraints will be allowed to compete in the economic test.

This screening process considers four factors which would limit the potential to substitute certain fuels for others in the 1985-1995 time frame. The first factor is the technical capability to use coal or oil. If the use of either of these fuels would contaminate products (such as in direct heat applications in food processing) or lead to equipment failure or safety hazards, then certain energy uses are precluded from selecting these fuels.

A second consideration related to the technical capability to utilize oil or coal is the lead time required for introducing new technologies not considered proven by industry. This is an important factor since coal is proven in only a few processes such as cement and lime kilns. Lead times for developing and testing new equipment configurations designed for coal firing may preclude from coal use new combustors scheduled to come on line prior to the commercial availability of coal-using equipment.

The third factor also relates to timing and applies only in 1985. Some fuel choice decisions already have been made; these decisions involve both new combustors already installed by 1978 plus commitments made for orders

of new combustors coming on line in the next few years. In evaluating fuel choice for new energy uses coming on line between 1975 and 1985, these decisions, based on past or current economics of fuel choice, must be considered.

The fourth factor used to screen the potential for fuel substitution is general economic considerations that effectively prohibit coal or oil use in certain applications. It is possible to prejudge that oil or coal use will not be economically feasible in some applications; these processes are discussed below.

Finally, other potential constraints on coal and oil substitution not explicitly incorporated into the model logic are discussed. Whether these factors, which are supply-related (e.g., equipment availability), will constrain coal or oil use depends on the magnitude of coal and oil demands generated by the model. A list of such factors and how they were considered in the use of IFCAM are discussed in this section.

Since the effect of these screening factors differs substantially for boilers and process heaters, these two combustor types are discussed separately.

5.2 BOILERS

5.2.1 Technical Feasibility

A boiler is a container in which water is evaporated continuously into steam by the application of heat. Hot combustion products heat water in tubes (watertube) or pass through tubes to heat water in a vessel (fire-tube). Boilers are distinguished by size (capacity, or pounds of steam produced per hour; or firing rate, MMBtu consumed per hour), operating pressure and temperature, fuel type, firing method, and whether they are shot-assembled at the factory (packaged) or field-erected on-site. Boilers generate steam for process uses or space heating and electricity generation.

Coal, gas, and oil use in boilers is a proven technology; coal and oil always have been primary boiler fuels. Steam quality generally is unaffected by fuel type, although there are small differences in boiler efficiencies related to fuel type and firing method. Boiler sizes as small as 30 MMBtu/hr equivalent commonly have been designed to fire coal, and there is no lower limit on boiler sizes burning gas or residual or distillate oil.

Boilers over 25 MMBtu/hr are primarily watertube boilers consisting of a drum with a multiplicity of tubes in which a water-steam mixture circulates. The watertube design is ideal for burning coal as well as conventional oil and gas. Boiler manufacturers have designed dependable package watertube boilers with underfeed or spreader stokers for capacities in the 4-60 MMBtu/hr range.

Smaller boilers (under 25 MMBtu/hr) are primarily firetube boilers. Firetube boilers have a drum containing water and pass hot combustion products through tubes within the boiler shell. In the United States, packaged firetubes are almost exclusively oil- or gas-fired. A coal-fired firetube boiler needs some added expense items -- ash handling, coal handling, and feeding -- which, in addition to storage and environmental control requirements, make coal use in firetube boilers subject to severe diseconomies of small scale operation. A coal-fired firetube boiler also has significant problems in dealing with any slagging or fouling in boiler tubes. Interior ash buildup on the tubes of a firetube boiler is considerably more difficult to clean than the exterior buildup on watertube boilers. While coal is considered a possible fuel for these units, coal use is unlikely to be economical.

5.2.2 Existing Boilers

Existing boilers can be retrofitted to burn oil or gas; they can be converted to coal either by reconverting units originally designed to fire coal or by accelerating replacement of existing units that never fired coal; conversion to any other fuel involves retrofitting the boiler. Retrofitting,

for coal use, oil/natural gas boilers that never were designed to burn coal is impractical for two reasons. First, boiler capacity must be downrated substantially (20 to 60 percent less than original design capacity) and second, necessary modifications to existing equipment may be physically impossible.

The primary constraint to modification is combustion volume. Significantly more combustion volume is required for burning coal than for burning oil or gas to insure that the flue gas temperature at the entrance to the boiler convective section is below coal's ash-softening point. Coal firing also requires additional burnout time to permit more heat absorption in the radiant (waterwall) section. If it is physically impossible or economically impractical to enlarge the furnace area, boiler capacity must be downrated substantially.

Other boiler constraints to coal conversion are convective section and air preheater redesign and the addition of sootblowers and fans. Because of these technical problems, conversion to coal firing of units not originally designed to burn coal are assumed infeasible unless the boiler is replaced.

5.2.3 New Boilers

New boilers include all boilers built between 1975 and 1985. Original analyses of National Energy Act (NEA) legislation proceeded under the assumption that the Act would not be enacted until the end of 1978; consequently, units built between 1975 and 1978 are not impacted by the Act. By the beginning of 1979, fuel choices for boilers coming on line through 1981 will have been made. Boiler lead times have been two to three years. Allowing for six months to a year for analysis, the bidding process, and clearance of environmental permits, there will be an additional two-year interval between the decision to build a boiler and the actual date when the boiler comes on line (lead times may be shorter for packaged units). Between the ordering and the final startup date for a large field-erected

boiler, a typical boiler manufacturer will require a series of payments starting with a 10 percent down payment roughly six months after the order date. For the following 18 months, payments are made up to 80 percent of the total boiler cost. The final 20 percent of payment is not made until the boiler is operating satisfactorily.^{1/} Therefore, a boiler that is to be built in mid-1981 already will be ordered and partially paid for in 1979.

Allowing for an average 2½ year new boiler order lead time and for units already installed by the end of 1978, if boiler energy demand is assumed to grow at a constant geometric rate, then about 50 percent of new boiler fuel use between 1975 and 1985 would not be affected by any proposed new energy policy measures.

5.3 PROCESS HEATERS

5.3.1 Issues

Direct coal use is a proven technology for only a small portion of current consumption of gaseous and oil fuels in process heat equipment (including retrofitting existing equipment and in new equipment).^{2/} Proven coal technologies exist primarily in cement and lime processing. Use of residual oil is less of a problem than coal in most processes; the exceptions are few, but include uses in food and several aluminum processes.

When coal substitution is technically feasible, coal use may be hindered by a lack of successfully demonstrated and commercially available equipment and more cost-effective equipment which uses other fuels. Capital investment decisions and safety and business risks also determine if a process application will be shifted from gaseous fuels to coal or oil. Business risks include the possibilities of equipment failure and loss of productive capacity or diminished product quality.

Technical capability was evaluated only for the option of direct coal firing in process heaters. Other alternatives which could increase reliance on coal include shifts from fossil fuels to electricity, process changes such as shifting from direct to indirect firing, or technologies which convert coal into gas or oil. The option to electrify rather than use fossil fuels is addressed explicitly in the MEFS model used to generate fossil fuel demand inputs into IFCAM. To the extent that process changes or coal conversion technologies have similar applicability, lead time, and costs as the direct-fired options in IFCAM, the estimates of coal use in process heaters generated by IFCAM would be as accurate as current data allow. However, technologies such as low-Btu gasification are technically feasible in process applications in which direct coal use is not feasible. Low-Btu gas also is commercially available and thus could be introduced into new units more rapidly than the direct coal alternatives evaluated in IFCAM.

Thus, exclusion of coal conversion technologies causes IFCAM to understate, to an unknown extent, the potential to use coal in the industrial sector. EEA has run one of its other models which includes the coal conversion technologies to obtain rough estimates of additional coal use from technology options not evaluated in IFCAM.^{3/}

5.3.2 Technical Feasibility

Some specific factors limiting the technical feasibility of coal or residual oil use in process heat applications include:

- Burner size.
- Heat distribution requirements.
- Fuel contaminants.

In evaluating the technical potential of fuel substitution for each industrial process, a distinction between new and retrofit units was made. This distinction was adopted because several existing process uses gradually are being phased out of production and replaced by newer, more efficient pro-

cesses and because some coal and oil use applications feasible in new uses cannot be retrofit into existing facilities. These constraints vary with different equipment configurations and by product process. As a result, each major energy-using process must be analyzed separately to determine the technical feasibility and risks associated with direct coal or oil use. The following subsections generally describe process heat equipment characteristics and then elaborate generally on the major technical coal or oil substitution problems. A detailed discussion of the technical potential for coal use in major industrial processes is provided in the report referenced above.

5.3.2.1 Process Heat Equipment Characteristics

Process heat equipment includes a furnace and auxiliary equipment that deliver heat energy to a product to raise its temperature for further processing or to cause a product transformation, including chemical reactions, physical changes in the crystalline structure, and phase changes (e.g., melting, evaporation). In direct-fired applications, combustion products can contact the material being processed. In indirect firing, a solid barrier separates the flame from the material.

Equipment sizes vary and are measured in terms of heat released, fuel consumed, or quantity of product processed. Processing can be continuous or batch jobs. Process heaters also are distinguished by the various ways products are transported through them. Fluid products generally are conveyed through tubes (as in a tubestill heater in petroleum refining and chemical industries) in a continuous process. Solid products may be moved mechanically or the furnace may move around the product. Operating temperatures and heat distribution patterns also characterize process heat equipment.

5.3.2.2 Major Technical Limitations

In this subsection specific technical problems of coal firing are discussed. Although many of these problems also occur when firing with residual oil, they are minor; coal firing greatly increases the severity of these technical constraints.

5.3.2.2.1 Coal Flame Characteristics and Burner Design

The coal flame is long, highly radiant, and slow burning. Because coal particles continue to burn in suspension, combustion may not be complete by the time the flame has traveled the length of the furnace. Flame impingement on furnace walls prior to complete combustion can cause slags to develop as the coal particles fuse and accumulate. Flame length and impingement can be controlled to a degree by burner design and positioning. Burners designed to project the coal in a swirling or cyclonic motion force the coal to spray in a wide pattern, thereby reducing the projection of the flame. However, reproduction of a short, sharp, gas-like flame is extremely difficult.

Burner size is an important parameter because some processes require a well-defined flame pattern and cannot tolerate local overheating; these requirements may restrict the combustion of solid fuels to larger burners in some processes. In other applications, combustion need only be completed by the time flue gases leave the firebox or before they reach the stack. Coal creates problems because its combustion time is longer than that for oil or gaseous fuels and its flame maintenance is more complex. If short, turbulent flames are not required (e.g., in cement and lime production), then burner size limitations do not constrain coal use.

The excess air requirement for coal combustion is higher than that for gas. Consequently, furnace volume and draft must be greater to assure complete combustion. Furnace volume increases also can result from the need to accommodate the length of the coal flame. In some applications, additional combustion air has to be supplied.

5.3.2.2.2 Heat Distribution

Heat distribution often is very important. Some processes require a uniform temperature while others use equipment with uneven, but controlled, temperature variations. In multiple burner applications, accurate fuel delivery is essential to maintain proper heat configurations. The heat released from an individual coal burner cannot be held constant because coal is a heterogeneous mixture and the coal delivery system cannot adequately control the amount of fuel delivered due to variable coal particle sizes. Even if a relatively constant fuel feed rate was attainable, heat input would not be constant because coal Btu content varies, resulting in swings of chemical heat input into the burner.

Conventional technology for firing coal, therefore, has a limited ability to respond quickly and accurately to furnace temperature fluctuations with an immediate fuel input response. Delivery of coal to the burner is more difficult than delivery of liquid or gaseous fuels. Special handling systems are required to grind and meter the coal properly prior to firing; such systems are not necessary for natural gas or oil. Although coal delivery systems have been developed recently* to meter pulverized coal to as many as 150 burners with adequate accuracy and control, the drawback of these systems is cost.

5.3.2.2.3 Fuel Contaminants

Fuel contaminants can impair product quality, accelerate furnace wear, or plug furnace passages. The product can be deteriorated by contaminants resting on or chemically combining with it. Furnace wear is caused by corrosion, erosion, and fluxing.^{4/} These adverse effects tend to increase costs, require earlier equipment replacement, and can affect equipment safety or reliability.

* For brick and refractory tunnel kilns.

Contaminants that most frequently affect solid fuel firing in furnaces are sulfur, vanadium, and ash. The sulfur content of coal varies between 0.6 and five percent and the ash content ranges from four to 20 percent of the fuel by volume. Vanadium and sulfur oxidize during combustion. Vanadium oxide spalls (deteriorates) refractories, corrodes metal surfaces (especially at furnace temperatures above 1000°F, and reduces furnace life. Sulfur oxides (SO₂) corrode metal at higher temperatures and also present an emissions problem.

Coal combustion produces an ash consisting primarily of silica, alumina, iron oxide, and calcium oxide. This ash can contaminate products through either simple contact with the product or a chemical reaction. Product deterioration ranges from cosmetic effects such as color or outside surface changes to more severe problems including the diminishing of a product's structural strength and the addition of undesirable properties to the product. In certain metal processing activities, surface scaling due to ash can be stripped away, but costs will be increased. Ash constituents occasionally are a necessary or neutral element to the product, as in cement manufacturing. In other cases, such as glass annealing, ash contamination probably cannot be tolerated.*

Ash also tends to attack furnace metals and refractory linings through corrosion and slagging. The refractory and ash combine at the refractory's surface to form a liquid or semisolid eutectic mixture which runs off the refractory wall. If this process is allowed to continue, the refractory wall tends to deteriorate. This problem is surmountable (at higher costs) in high-grade refractories that bring the fluxing action within tolerable limits.

* In some cases, direct-fired process heaters can be replaced by indirect-fired heaters to avoid product contamination at the expense of higher equipment costs.

If furnace temperatures exceed the ash fusion point of coal, ash is deposited on the furnace walls and refractories and furnace efficiency is reduced. The liquid form of ash cannot be removed without shutting down the furnace. Ash also tends to impair furnace and heat recovery equipment through plugging. In solid form, ash plugging can be overcome by equipment design and mechanical sootblowing techniques. Plugging problems are more severe at furnace temperatures at which ash fusion can plug flue gas outlets or heat recovery equipment passages.

In conjunction with sulfur, ash corrodes metal tubes or other surfaces in the furnace. The corrosion problems become more severe at higher furnace temperatures (1000-1400°F) which speed up corrosive chemical reactions, although there is a dropoff after 1450°F. To some extent, corrosion can be minimized (again, at higher costs) by using special corrosion-resistant alloys. However, many of these alloys do not have sufficient structural strength to be employed at higher furnace temperatures when the corrosive effects of sulfate are most severe. Higher chrome alloys (>30 percent chromium) sacrifice structural strength for corrosion resistance up to about 1000°F. Chromium nickel stainless steels have greater structural strength than high chrome alloys but also resist corrosion only up to approximately 1000°F. Nickel-based super alloys can be used at high temperatures without sacrificing tensile strength, but are susceptible to chloride attack.

5.4 SUMMARY OF TECHNICAL FEASIBILITY EVALUATION

In considering the technical feasibility of coal and oil use, each process application is classified into one of the following four categories, based on the severity of technical risks.^{5/}

Proven: In these applications, coal or oil has been used in commercial scale processes within the United States. The technology has been sufficiently proven to support commercial ventures.

Low Risk: For these process applications, it should be possible to construct and operate successfully a coal- or oil-fired unit without significant risk of failure. In every case, however, a new design must be prepared. For example, the majority of heaters in the petroleum refining industry currently are designed with underfiring. Coal-fired heaters would have to be designed with burners firing vertically downward or from the side of the furnace to prevent ash from falling onto the burners. The new design would have to handle differences in flame characteristics, volume of the firebox, and other special problems associated with coal burning discussed earlier. Low risk essentially represents surmountable technical obstacles, but the unit must be built and demonstrated before it can be considered commercially available.

High Risk: In these process applications, the obstacles to coal or oil use are more severe. Use of coal may impose special design problems, higher risk of materials failure, equipment downtime, or greater safety hazards. For these processes, it may be possible to apply coal effectively but the risks of failure are much greater than for the low risk category.

Probably Infeasible: For these processes, the problems of coal or oil use appear to be so severe that unless new breakthroughs in design or material quality occur, coal cannot be burned.

In the operation of the model, the risk evaluation does not change for 1985, 1990, and 1995. Thus, a high risk fuel use in a process in 1985 might become low risk by 1990 and proven in 1995 but will be considered in the model as a high risk alternative from 1985 on. Likewise, when the use of a certain fuel in a process was considered infeasible in 1985, it also was considered infeasible in 1990 and 1995. This assumption introduces some bias against coal or oil use to the extent that technological breakthroughs are made.

The model can be operated given any assumption regarding technological risk. Generally, the model has been operated including proven, low, and high risk technology options. However, it could be operated allowing only proven or proven plus low risk technological options, thus limiting the potential market penetration of residual oil and coal.

The results of the technical analyses suggest that most potential coal use in process applications is in the petroleum refining, SCG, steel, and aluminum industries (see Table 5.1). Table 5.2 also emphasizes that the technical potential for coal use is higher for new units than it is for retrofitting existing units burning oil or gas. Residual oil use, however, has much wider potential; retrofits or new units are considered feasible in most of the processes specifically studied. See Appendix G for process-by-process detail on the feasibility of coal or oil use.

5.4.1 Lead Time

For all processes technically capable of using coal, there are lead time factors affecting the date of commercial availability. For a proven technology, coal use is limited only by commitments already made in an analogous manner to the new boilers discussed earlier. However, when coal firing technology is not proven, other factors affecting commercial availability and market penetration of the new technology must be taken into account. Table 5.3 provides an example of additional lead time factors necessary when coal use in a technology is unproven, for example, coal use in new tubestill heaters for atmospheric crude oil distillation.

The first key assumption in this scenario is that either the private or public sector initiates development of the coal firing technology in January 1979. In this optimistic scenario, it takes two years to design and construct one or more commercial facilities. One year is allowed for thorough testing and operational experience.^{6/} Assuming successful operating experience, a minimum of two or more years is necessary for construction lead

TABLE 5.1 TECHNICAL FEASIBILITY OF COAL USE BY INDUSTRY
IN PROCESS HEAT APPLICATIONS^{a/}

<u>Industry</u>	<u>Combustor Application</u>	
	<u>New - % of all fossil fuel use in new units</u>	<u>Retrofit - % of all oil and gas use in existing units</u>
Food	0	0
Textiles	0	0
Paper	0	0
Chemicals	2	1
Petroleum	78.8	.0
SCG	87	83
Steel	44	44
Aluminum	70	70
Other	0	0
Total	51	22.3

^{a/} Includes proven, low risk, and high risk assessments.

SOURCE: Derived from "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report, prepared by Energy and Environmental Analysis, Inc., for Department of Energy, May 22, 1978.

TABLE 5.2 TECHNICAL SUBSTITUTION POTENTIAL:
 COAL FOR GASEOUS AND OIL FUELS IN PROCESS HEAT EQUIPMENT^{a/}
 (% of evaluated industry consumption of gaseous and oil fuels)

<u>Risk Category</u>	<u>New Units</u>	<u>Retrofit of Existing Units</u>
Proven	14.8	7.4
Low-Risk	22.6	13.3
High-Risk	13.6	1.6
Infeasible	45.5	72.1
Not Accounted For	<u>3.5</u>	<u>5.6</u>
TOTAL	100.0	100.0

a/ Gaseous fuels for the purposes of this table include methane, propane, butane, liquefied petroleum gas, and refinery off-gas. Oil fuels include No. 1 fuel oil, No. 2 fuel oil, kerosene, diesel oil, No. 5 fuel oil, No. 6 fuel oil, tar, and pitch.

SOURCE: Energy and Environmental Analysis, Inc., "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report, prepared for Department of Energy, May 22, 1978, pp. I-3, I-4.

TABLE 5.3 MARKET PENETRATION LEAD TIMES FOR A
NEW COAL-FIRED NONBOILER USE: OPTIMISTIC SCHEDULE

Example: Atmospheric Crude Oil Distillation Tubestill Heater

- Start date January 1, 1979
- Demonstration time:

Construction period	2 years
Proving experience	<u>1 Year</u>
Total	3 years
- Construction of new commercial coal facility 2 years
- Initial year of market penetration 1984
- Percent of market penetration in 1984 20 percent

time to install the first commercial scale facilities. Adding the demonstration and construction lead times, units coming on line in 1984 would be the first ones which might fire coal. Not all new units, however, would select coal even if it were the economic choice. Past experience suggests that new technologies are installed at a relatively slow pace as companies test the units in their own facilities and gain operation experience before accepting a new technology. The estimated rate of market penetration was derived from past experience based on the penetration rate for new hydrocracking equipment from 1968-1977.^{7/} Extrapolating from that experience, 20 percent of the new units coming on line in the 1984-85 time period would select coal firing if it were economic. If energy demands to fire new tubestill heaters were evenly distributed over the 1975-85 period, then a maximum of three percent of the energy use in new tubestill heaters could select coal if the economics were favorable.^{8/} A less optimistic time schedule would reduce market penetration by 1985 to zero.

An identical approach was followed for all processes technically capable of burning coal. See Appendix G for a list of the lead time factors for all technically feasible coal firing processes.

5.5 OTHER CONSTRAINTS NOT EXPLICITLY DEALT WITH IN IFCAM

The use of certain fuels is limited by two types of potential constraints which are not explicitly incorporated into the model framework. The first constraint is site-specific factors that would preclude use of a certain fuel, especially coal, in otherwise economical situations. The second set of constraints, relating to supply questions, is not tested explicitly in the model, but must be kept in mind.

Site-specific constraints include factors such as limited land or space requirements, particularly in the case of existing plants. The failure to incorporate any specific downward adjustment for space constraints tends to bias the results in favor of additional coal use. Data on such constraints are not readily available. The effects of such factors can be simulated

arbitrarily by assuming that a certain percentage of coal or oil use in existing facilities is precluded by siting considerations.

It is important to remember that IFCAM is strictly an energy demand model and that any supply-related constraints are considered external to the model. The model results must be viewed in interaction with an energy supply model to provide equilibrium fuel use results. In reality, gas, oil, and coal supply availability may constrain the level of demand for certain fuels in some regions, as will constraints in the form of backlogs in orders for pollution control equipment and boiler and process application equipment. The effect of the supply factors, particularly those which could limit coal use, have been analyzed outside the model framework.

FOOTNOTES

1. Personal communication with Mr. Carl Farmer, Combustion Engineering, Power Division, October 13, 1977.
2. Energy and Environmental Analysis, Inc. "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report prepared for DOE, May 22, 1978.
3. Energy and Environmental Analysis, Inc., "Industrial Sector Technology Use Model (ISTUM): Industrial Energy Use in the United States, 1974-2000," Prepared for DOE, April 28, 1978.
4. Fluxing is the combining of a new component with a solid to lower the melting point (e.g., salt and ice). Constituents of coal ash have this effect on some refractories.
5. These categories refer only to conventional process heater designs and do not apply to gasification technologies. The evaluation also does not consider the potential to shift from direct-fired process equipment (where coal combustion products impact directly on the product being processed) to indirect firing (where combustion products do not come in direct contact with the products being processed). If such shifts are feasible, the potential for coal use is greater than indicated in this report.
6. Other timing scenarios which have less optimistic assumptions of a five-year development period also can be run.
7. Oil and Gas Journal, Annual Refining Survey, 1968-1977.
8. 1984-1985 covers 15 percent if the interval of new energy demands are the same each year. Applying the 20 percent penetration rate to 15 percent of the energy implies a maximum coal market penetration of three percent.

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6. ASSIGNMENT OF ENVIRONMENTAL REGULATIONS AND POLLUTION CONTROL STRATEGIES

6.1 INTRODUCTION

Environmental regulations play an important role in determining the amount of industrial fuel use which can be satisfied by coal and residual fuel oil. Environmental regulations alter relative capital and fuel costs and may preclude the use of certain fuels in combustors. Specific regulations can vary according to geographic location, combustor size and type, and fuel type. Both federal and state regulations influence fuel choice selection.

Three classes of environmental regulations were considered in IFCAM: NSPS; State Implementation Plans, or SIP's; and the designation of certain areas referred to as "nonattainment areas," where air quality exceeds federally mandated standards for certain pollutants. Each of these three classes of regulations was examined in relation to two basic fuel types (coal and oil) and two principal pollutants (TSP and SO₂).

The impact of these regulations was accounted for in a four-step process. First, each combustor was assigned to an AQCR based on historical location patterns of industrial energy consumption. Second, the specific emission limit of each combustor was identified. Next, pollution control equipment and the fuel quality required to meet emission limits were specified, since these elements determine how capital, operating, and fuel costs are affected by environmental requirements. Finally, combustors located in areas designated by each state as not attaining National Ambient Air Quality Standards (NAAQS) for either TSP or SO₂ were identified. In such areas, combustors could face higher costs of burning high-polluting fuels or could be prohibited

from using these fuels, particularly coal. This section describes each of these four steps sequentially.

6.2 ASSIGNMENT OF COMBUSTORS TO AQCR'S

6.2.1 Introduction

The environmental regulations that apply to any type of combustor can vary significantly from one AQCR to the next. Whereas NSPS provisions apply equally in all parts of all regions, SIP provisions often vary between AQCR's and, in some cases, between areas within AQCR's. In order to assign the appropriate SIP emission limits, all combustors were "located" in a specific AQCR.

6.2.2 New Boiler Location

Within each region, new boilers were located randomly by AQCR according to historical patterns. Within each region and fuel type, a cumulative distribution function was developed for the level of fuel use in each AQCR. The fuel-specific distribution of fuel use among AQCR's was based on a 1975 working paper which used EPA emission inventory data (including fuel use).^{1/} If AQCR #1 consumed three times as much fuel as AQCR #2 consumed, then each new boiler (in each industry, size/capacity utilization class) was three times more likely to site in AQCR #1 than in AQCR #2.

No attempt was made to model changes in industrial location patterns. Such trends are extremely difficult to identify and project and certainly were beyond the scope of this effort. Consequently, state and local environmental regulations implicitly were assumed not to influence industrial location patterns. This assumption introduces a bias against the selection of coal. Using historical location patterns to predict future location patterns concentrates new energy consumption in areas where energy consumption has been located in the past. New energy uses, therefore, will be located in areas where air pollution problems already exist. Because coal produces more of

the critical pollutants (SO_2 and TSP) than other fuels and generally incurs higher costs for the removal of these pollutants, coal use may result in higher cleanup costs or may be prohibited completely in AQCR's which already confront serious air quality problems. If future industrial energy location patterns tend to shift away from existing concentrations of energy use, then the costs of using coal will tend to be lower or coal will be prohibited to a lesser extent than that forecast by IFCAM.

6.2.3 Existing Boiler Location

In a previous study, EEA identified the AQCR location of existing boilers in the MFBI file.^{2/} By reviewing the city, county, state, and zip code information on the survey forms, EEA coded the AQCR on existing boiler records. Consequently, no additional effort was required to locate existing boilers.

6.2.4 Location of Process Heaters

Existing and new process heaters were allocated among AQCR's in the same manner as new boilers were allocated, i.e., by a cumulative probability scheme using distributions based on historical patterns of energy use in industrial combustion processes. No functional use detail was included in these distributions, although some data sources do exist regarding the locational patterns of certain types of nonboilers. For example, the MFBI includes nonboilers with firing rates greater than 100 MMBtu/hr. MFBI data for nonboilers were not used, however, for two principal reasons. First, MFBI coverage does not include nonboilers with firing rates smaller than 100 MMBtu/hr. This cutoff excludes a substantial portion of nonboiler energy use. Second, matching up the specific definitions of the nonboiler processes on the MFBI file with the nonboiler categories included in the model proved to be quite difficult and too uncertain to be useful. Other sources for the locational detail of nonboilers, including information from trade associations and published reports, could be used, but such an effort was beyond the scope of this study.

6.3 ASSIGNMENT OF ENVIRONMENTAL REGULATIONS TO INDIVIDUAL COMBUSTORS

6.3.1 Scope

The fuel choice decision for any combustor must consider relevant environmental regulations. A variety of environmental regulations may apply to any combustor depending upon combustor type, size, and fuel type. The environmental regulations considered relevant to any combustor directly determine the type of fuel which can be used and the kind of pollution control equipment required.

Of the six pollutants subject to NAAQS, regulations were examined in this analysis for only two: SO_2 and TSP. While industrial fuel burning sources also emit significant quantities of nitrogen oxides (NO_x), current emission limits generally are met by combustor design rather than by control equipment. NO_x emission limits may become a significant cost factor following promulgation of a new air quality standard for nitrogen dioxide (NO_2). However, this analysis was confined only to SO_2 and TSP. For three of the NAAQS pollutants -- carbon monoxide, hydrocarbons, and photochemical oxidants -- industrial processes either emit only negligible quantities or quantities which do not differ significantly among fuel types.

A total of six different fuel types were considered in IFCAM: high sulfur coal, low sulfur coal, high sulfur residual oil, low sulfur residual oil, distillate oil, and natural gas. Of these, distillate oil and natural gas were assumed to emit insignificant levels of SO_2 and TSP.^{3/} Environmental regulations limiting emissions of SO_2 and TSP were assumed to apply to coal and residual fuel oil.

The environmental regulations considered in IFCAM were those promulgated by federal and state agencies. Federal regulations were accounted for directly in assumptions regarding NSPS -- national standards which apply equally to all regions and only to new boilers with firing rates above a specified cutoff. Recent Clean Air Act amendments require the "best systems of

emission reduction available" for all combustors to which NSPS apply. Although current NSPS provisions apply to all new boilers with firing rates above 250 MMBtu/hr, these regulations are being revised for consistency with recent legislative amendments. State regulations were accounted for in assumptions regarding SIP's.

Environmental regulations were examined for their impact on three general classes of combustors: (1) boilers subject to NSPS; (2) boilers subject to SIP's; and (3) nonboiler processes. The regulations applicable to each of these categories are discussed separately below.

6.3.2 New Boilers Subject to NSPS

Currently, all boilers constructed or modified after 1972 that have firing rates greater than 250 MMBtu/hr are subject to NSPS provisions. Both coal- and oil-fired units are covered by NSPS. IFCAM can evaluate several possible versions of NSPS. Current NSPS size cutoff and emission limits for coal are as follows: SO_2 cannot exceed 1.2 lb/MMBtu and TSP cannot exceed 0.1 lb/MMBtu in units greater than 250 MMBtu/hr. These NSPS standards were applied to all units operating before 1982. For those units put on line after 1982, new NSPS standards were used. These standards in the sample model runs are based on proposals for BACT requirements on all boilers firing at a rate equal to or greater than 100 MMBtu/hr, as well as stricter emission limitations.

6.3.3 Boilers Subject to SIP's

All existing boilers and new boilers below the NSPS size cutoff are subject, not to NSPS, but to SIP's. Boilers subject to NSPS were assumed to have faced standards as strict or stricter than those used in SIP's. SIP's for SO_2 and TSP vary substantially within and between states, both in the severity of the standard and the way in which it is expressed. Although some states specify standards only in terms of ambient conditions, most states specify them in terms of pounds of pollutant per energy release of

the fuel (lbs/MMBtu) or pollutant content of the fuel, by weight, in percentage terms. Some SIP's are constant across an entire state, but many vary among AQCR's and, in some states, among counties within AQCR's. Emissions regulations in IFCAM for SO₂ and TSP were analyzed at the AQCR level. For each AQCR where SIP's exist, regulations were converted to lbs/MMBtu.^{4/}

In many states, SIP regulations vary by fuel type and boiler size. When this was the case, SIP's were classified among three boiler size categories: 25-100 MMBtu/hr, 100-250 MMBtu/hr, and greater than 250 MMBtu/hr. A typical SO₂ regulation might set an emission limit of 1.8 lb/MMBtu for large boilers but allow a 3.5 lb/MMBtu limit for a small boiler. The applicable emission limit of both SO₂ and TSP for each combustor were identified in the model.

6.3.4 Environmental Standards for Process Heaters

The assignment of emission limits for fuel burning in process heaters was not defined as clearly as it was for boilers. This is largely a consequence of the historical reliance of process heaters on gas and fuel oil. Many process sources which are controlled, such as sulfuric acid plants, are not related to fuel combustion. The few processes which use coal, such as cement kilns, generally are not major emitters due to the nature of the production process. For example, coal ash becomes an element of the product in cement manufacturing. More generally, current SIP's applicable to process sources may become completely outmoded or irrelevant given fuel use trends away from natural gas. In cases in which gas currently is being used, SIP's may not be applicable to oil or coal.

As a result of these problems, a hypothetical set of regulations is applied to certain process sources, depending on the general context of the environmental regulatory scenario. These scenarios are specified directly in terms of pollution control strategies and are discussed in the following section.

6.4 ASSIGNMENT OF POLLUTION CONTROL STRATEGIES TO MEET SPECIFIED EMISSION LIMITS

6.4.1 Boilers

6.4.1.1 Approach

Emission limits derived above for coal and residual fuel oil will affect both the fuel quality (sulfur content) and pollution control equipment required by each combustor. Since natural gas and distillate fuel oil are inherently clean fuels, it was assumed that they can satisfy any sulfur or particulate control requirements.

The combination of control equipment and fuel quality requirements associated with sulfur and particulate emission limits is shown in Table 6.1. In the case of coal, an appropriate quality of low sulfur coal, FGD, or some combination of the two approaches can be used to satisfy emission limits. For the highest sulfur emission limits, above 3.5 lbs SO₂/MMBtu, locally available high sulfur coal was assumed to be satisfactory. For emission limits in the 0.8-3.5 range, low sulfur coal was assumed to be used to satisfy sulfur regulations while an FGD was required when burning high sulfur coal. FGD was assumed to be used in conjunction with high or low sulfur coal to meet more restrictive regulations. The Best Available Control Technology (BACT) requirement reflects an interpretation of the recent Clean Air Act amendments that FGD and ESP will be required in conjunction with locally available coal.

These control strategies established to satisfy sulfur emission limits for coal firing are oversimplified in several respects. Emission sources will, in reality, select the least cost choice of low sulfur coal or FGD (except for the BACT and lower emissions scenarios). A combustor with a 0.8-3.5 regulation may find it cheaper to clean a portion of the flue gas stream (called partial scrubbing) rather than use a higher price coal. Conversely, a small boiler with a low capacity utilization rate may choose to utilize

TABLE 6.1 POLLUTION CONTROL STRATEGIES FOR COAL

Emission Limit (lb/MMBtu)	Control Equipment ^{a/} Used with	
	High Sulfur Coal	Low Sulfur Coal
Sulfur Dioxide		
BACT (late ^{b/})	FGD	FGD
Current NSPS (early ^{c/})	FGD	-
SIP		
<0.8	FGD	FGD
0.8-3.5	FGD	-
>3.5	-	-
Particulates		
BACT (late ^{b/})	ESP	ESP
Current NSPS (early ^{c/})	ESP or FGD ^{d/}	ESP
SIP		
<0.07	ESP	ESP
0.07-0.3	ESP or FGD ^{d/}	ESP or FGD ^{d/}
>0.3	C	C

^{a/} C = cyclone; ESP = electrostatic precipitator; FGD = flue gas desulfurization.

^{b/} Applies to new units operating after 1982.

^{c/} Applies to new units operating by 1982.

^{d/} ESP if FGD not required to meet sulfur limit; FGD only if required to meet sulfur limit.

a very low sulfur coal to satisfy a 1.2 lb/MMBtu regulation rather than install FGD equipment. The control options listed in Table 6.1 thus tend to overstate the environmental costs of coal in meeting sulfur emission limits.

In addition to the above factors, new boilers subject to NSPS regulations may not be required to control emissions below a "floor" of 0.2-0.5 lb SO₂/MMBtu. In certain situations, such as plants in Texas using low sulfur coal from Wyoming, units may be able to use a partial scrubbing strategy to achieve a BACT control scenario. Since FGD typically has been applied to the entire flue gas stream (100 percent scrubbing), control costs again will tend to be overstated for coal.

Emission limits for residual fuel oil are given in Table 6.2. It was assumed that no extra control was necessary for oil which was desulfurized and blended at the refinery (low sulfur residual oil). High sulfur oil was assumed to require FGD for emission limits under two lb/MMBtu and BACT-covered units. No special controls were considered necessary for less stringent SIP's.

Particulate emission limits can be met by mechanical cleaning devices such as cyclones or mechanical collectors if minimal particulate control is required. FGD, ESP, or baghouses can be used to meet more stringent emission limits (under 0.16 lb/MMBtu). Since FGD can satisfy both sulfur and particulate emission limits, this process can be used without an ESP to meet both standards if the TSP emission limit is not too stringent.

Particulate control for residual oil is achieved with the same control strategies (except that baghouses cannot be used). Residual oil use, however, requires less control equipment than coal requires to achieve the same emission limits because of the inherently lower TSP emission from a residual oil-fired boiler. This difference is accounted for roughly by requiring ESP on oil only for the more stringent regulatory emission limits.

TABLE 6.2 POLLUTION CONTROL STRATEGIES FOR RESIDUAL OIL

<u>Emission Limit (lb/MMBtu)</u>	<u>Control Equipment^{a/} Used with</u>	
	<u>High Sulfur</u>	<u>Low Sulfur</u>
Sulfur Dioxide		
BACT (late ^{b/})	FGD	-
Current NSPS (early ^{c/})	FGD	-
SIP		
≤ 2.0	FGD	-
> 2.0	-	-
Particulates		
BACT (late ^{b/})	ESP	ESP
Current NSPS (early ^{c/})	- ^{d/}	ESP
SIP		
≤ 0.16	ESP	ESP
> 0.16	C	C

a/ C = cyclone; ESP = electrostatic precipitator; FGD = flue gas desulfurization.

b/ Applies to new units operating after 1982.

c/ Applies to new units operating by 1982.

d/ FGD required to control SO₂ emissions also will control TSP emissions to the required degree.

6.4.1.2 Environmental Requirements in the Sample Run

New boilers in operation by 1982 in the sample run were assumed to be required to satisfy only the current NSPS. For boilers above 250 MMBtu/hr rated capacity, the sulfur emission limit was 1.2 lb SO₂/MMBtu and the particulate limit was 0.1 lb/MMBtu. These requirements were satisfied by the use of high sulfur coal in conjunction with FGD. Low sulfur oil without an ESP was assumed to provide adequate control for new large residual oil-fired boilers.

New units put into operation after 1982 were assumed to have to meet newer, more stringent BACT requirements recently proposed. These requirements, applicable to all units greater than 100 MMBtu/hr, were required to use both FGD and ESP to meet SO₂ and TSP limits when using coal of any sulfur content and high sulfur residual oil. Only an ESP was required when considering low sulfur residual oil.

6.4.2 Process Heaters

Emission limits for coal-fired process heaters are difficult to assess since coal is used in only a few process applications and few regulations regarding coal use currently exist. Emissions for the most important coal-using process, cement kilns, do not pose significant problems since they are absorbed into the product rather than passed into a flue gas stream. Given that uncontrolled emission rates under coal firing are not known at this time, the emission controls required for direct burning of coal as a solid fuel in process heaters necessarily are conjectural. Basically, an ESP was required for all coal-fired process heat applications but not for oil-fired process heaters. FGD was required for new coal-fired process heaters in petroleum refining and other selected applications (e.g., reverberatory furnaces) either when high emissions seemed likely or when stringent sulfur controls already were required on process equipment. Process-specific environmental control strategies are detailed in Appendix G.

6.5 OTHER ENVIRONMENTAL REQUIREMENTS

In addition to the NSPS and SIP requirements discussed above, two other currently evolving environmental restrictions can influence fuel choice decisions. The first are those restrictions applicable in air quality problem areas (nonattainment zones) and the second are regulations (Prevention of Significant Deterioration, or PSD regulations) which are applicable in clean air areas.

6.5.1 Nonattainment Areas

Nonattainment areas are zones in which air quality standards for specified pollutants are being exceeded. The EPA has called for revisions to the SIP's in these areas to insure that reasonable progress toward air quality goals by legislatively mandated schedules (1982 or 1987) will be achieved. States are required to submit SIP revisions by 1979. The effect of these revisions cannot be forecast accurately at this time. The costs of fuel use (especially coal) can be affected, depending on the severity and nature of the air quality problem and the strategy selected by state and local governments. If air quality problems are caused by only a few large emission sources, then only these sources might be required to reduce emissions. In other instances, all coal-fired sources might be required to install FGD and ESP. In still other cases, new sources may be required to install FGD and ESP as well as purchase emission reductions (called emission offsets) from existing facilities equal to or greater than emissions generated by the new facility.

In IFCAM, the nonattainment problem was approached by first identifying fossil fuel use in nonattainment areas. This identification was accomplished through a list provided by EPA in the summer of 1977. This list specified, by county, areas anticipated to be defined as nonattainment areas.* Since fuel use in IFCAM is identified (using historical patterns) only at the

* EPA issued an official list of nonattainment areas early in 1978, but the data files in IFCAM have not yet been updated.

AQCR level, the percentage of fuel use within affected counties in the AQCR was assumed to be directly proportional to the percentage of land area contained in the affected counties.

Once the projected fuel use in nonattainment areas was identified, higher cost control options could have been used to simulate the effect of revised SIP's and new source control levels. In IFCAM, however, a much cruder approach is used to simulate the impact of nonattainment area policies. This approach makes the extreme assumption that these policies will either directly prohibit coal use or make coal so expensive that alternative fuels always will be selected. Consequently, even when coal use is technically feasible and economically the cheapest source of energy, it is precluded in all nonattainment areas.

This approach to simulating the effect of SIP's and new source control levels has two conflicting biases. First, precluding any coal use in nonattainment areas clearly overstates the cost of coal use in relation to oil or gas usage; the extent of this bias can be determined only after the revised SIP's are finalized. On the other hand, fuel use in affected nonattainment areas probably has been understated by the assumption that fuel use in affected counties within an AQCR is in the same proportion as the affected counties' land area within the AQCR. In fact, a greater share of fuel use probably is located in counties with severe air quality problems since that is where industry will tend to be concentrated. Due to these problems, the approach used in IFCAM to assess the impact of nonattainment areas on coal use can be considered only a rough approximation.

6.5.2 Clean Air Areas

Outside of nonattainment areas, states are required to insure that air quality as a consequence of economic growth does not deteriorate beyond specified increments in air quality levels. New sources with emissions above a certain level are required to comply with BACT limits applied on a

case-by-case basis considering both cost and energy implications. As in the case of nonattainment areas, state and local governments have considerable flexibility in implementing these regulations. They can control new sources stringently or limit existing emission sources in order to provide a larger emission increment for new sources, thereby encouraging a higher rate of economic growth.

While the capability exists in IFCAM to specify separate emission limits for PSD areas, the model has been run assuming that the national NSPS will be equivalent to the case-by-case BACT in PSD areas. Since EPA guidelines for the determination of BACT have just been issued to the states, it is too early to predict the stringency of control requirements in PSD areas.

FOOTNOTES

1. The MITRE Corporation, "Fossil Fuel Demand for Stationary-Source Combustion and Other Selected Data for Each State and Air Quality Control Region," working paper, April, 1975. Fuel mix by AQCR is based upon 1971 data from a Battelle Columbus study done for EPA.
2. Final Revised Environmental Impact Statement, Coal Conversion Program, Energy Supply and Environmental Coordination Act (as amended), Section 2, FES-77-3, May, 1977.
3. Environmental Protection Agency, Compilation of Air Emission Factors, AP-42, 2nd Edition, 1976.
4. Equations used for converting regulations expressed in alternative forms were used from "State Implementation Plan Emission Regulations for Sulfur Oxides: Fuel Combustion," Appendix C, EPA-450/2-76-002a, September, 1977.

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7. ECONOMICS OF THE FUEL CHOICE DECISION

7.1 INTRODUCTION

This section presents the method by which the fuel choice investment decision for the industrial sector is simulated. For each combustor process, the costs of direct coal use are compared with those of oil and gas. This comparison, simulated at the combustor level, employs standard industrial investment criteria. For instance, any combustor for which the economics of coal use prove favorable when compared to those of oil and gas is considered to use coal. The economic criteria dictate that the fuel which is the least costly over the life of the investment is the fuel chosen.

This section contains three major parts. First, the components of capital and operating costs are introduced and discussed. Second, fuel prices and total costs of consuming energy are developed. Finally, the fuel choice decision framework is presented; investment criteria are identified, and an example is developed.

7.2 COST COMPONENTS

7.2.1 Capital Costs

This section examines the components of capital cost estimates: equipment components, the methodology used to derive cost estimates, and the nature of data sources. Costs are presented for prototype combustor configurations. Capital costs are discussed separately for new boilers, existing boilers, and process heaters. Details concerning the derivation of equipment required to use alternative fuels, cost algorithms, and data sources are presented in Appendices H and I.

7.2.1.1 New Boiler Costs

Boiler cost calculations are based on costs for a single boiler installation. This assumption tends to overstate costs for cases in which several boilers are sited at one plant since plant economies of scale for fuel handling and environmental control equipment are not taken into account.

In boiler cost evaluations, coal-fired boilers are compared to boilers which can fire oil and natural gas. The major items of boiler-related equipment which differ according to the type of fuel fired are described briefly below.

7.2.1.1.1 Boiler Equipment

This category includes equipment which conveys the fuel from working storage, prepares the fuel, burns the fuel, and creates steam. A partial list of equipment items covered under boiler costs includes:

- Furnace and tubes.
- Burners.
- Conveyor belt (coal only).
- Hopper (coal only).
- Pulverizer or stoker (coal only).
- Coal bunker (coal only).
- Control equipment.
- Exhaust blowers.
- Ignition equipment.

Boilers can be purchased in several different types and sizes and boiler design and costs are influenced primarily by the following parameters:

- Fuel type.
- Steam quality.
- Firing method.
- Capacity.

In IFCAM, all boilers greater than 25,000 lbs of steam capacity per hour are assumed to be watertube units. Smaller units are assumed to be fire-tube units. Gas and oil boiler costs for these firetube boilers are based on the assumption that these boilers have dual-fired capability.

Boilers also may be classified as packaged (shop assembled) or field-erected. Oil or gas boilers with less than 250,000 lbs of steam capacity per hour are assumed to be packaged units which can be shipped by rail, truck, or barge. Packaged boilers have lower installed costs per pound of steam capacity per hour at small size ranges than field-erected boilers.^{1/}

Coal boilers are assumed to be field-erected. The firing method used by coal boilers depends on size. Coal boilers less than 250,000 lbs/hr are assumed to be stoker-fired; larger coal boilers are assumed to be pulverized coal-fired.

Boiler steam temperatures range from saturation to 1000°F and pressures reach up to 1500 psig. This analysis subsumed differences in steam quality requirements because of the degree to which these requirements vary, even within specific industries. Average steam quality for large new industrial units, based on a review of recent ABMA data on new watertube boiler orders, equals 700°F and 700 psig. Small packaged watertube boilers have lower pressures and temperatures, typically, 250 psig and saturated steam temperatures. Firetube units may operate at 150 psig and saturated steam temperatures.

Boiler costs, based on estimates provided by equipment vendors, have been compared to installed costs reported by fuel users.

7.2.1.1.2 Fuel Handling, Storage Equipment, and Fuel Stockpiles

The type of fuel handling and storage system employed depends on the annual volume of fuel use at each plant, fuel type, and available fuel transportation options. There are significant economies of scale with respect to

capital costs as a function of annual fuel requirements. For this analysis, three coal handling systems were designed as a function of annual fuel requirements. These systems assume rail or truck delivery of coal. Most industrial plants do not qualify for unit train coal shipments because they consume much less than 500,000 tons of coal annually.^{2/} In order to simplify this analysis, barge delivery also was not considered. Consequently, handling costs are overstated to the extent that water-based transportation is available to industrial plants.

The coal handling systems include equipment used to unload the coal, transfer it to a coal pile, reclaim it from the coal pile, and deliver it to bunkers in the powerhouse. Also included in the system is an outdoor coal pile with a layer of limestone that controls drainage. Silo storage is not included because land is assumed to be available for an outdoor coal pile. A 30-day supply of coal is assumed to represent the size of a typical industrial coal stockpile.

An oil handling and storage system consists of a storage tank, pumps, and a heater. Heating equipment is required to facilitate the pumping of heavy residual fuel oil. A three-week supply of fuel oil was assumed to represent the size of the oil stockpile.

Unlike coal and oil, natural gas normally is not stored on-site and the hookup of gas mains and pipes is included elsewhere in site preparation and offsite utility costs for new plants.

7.2.1.1.3 Ash Handling Equipment

Ash handling equipment is necessary for coal-fired boilers because coal contains a significant percentage (five to 20 percent by weight) of non-combustible solid materials which must be removed from the bottom of the boiler and from the environmental control equipment (which removes fly ash from the stack gases). Key parameters that determine the cost of ash handling equipment include:

- Firing method (stoker vs. pulverizer).
- Boiler size and environmental control system.
- Type of ash handling system.

The firing method is significant because it determines the amount of ash deposited at the bottom of the furnace versus the amount of ash entrained in the flue gas. When pulverized coal is burned, all the ash particles are formed and most remain in suspension. Approximately 80 percent of the ash is fly ash and the remainder is bottom ash. In contrast, only about 10-20 percent of the ash in a stoker-fired boiler is fly ash; the remainder is bottom ash because most of the combustion occurs in the fuel bed.

The ash handling system collects the ash from hoppers and transports it to a storage or dewatering bin. The cost of disposing of this combustion residue is included in annual operating costs. There are two common methods for handling ash: hydraulic and pneumatic. Hydraulic systems use water to convey ash from the collection hopper to the disposal point. Pneumatic systems use compressed air (or other gases) for this purpose. The latter system is assumed to be more applicable to industrial installations.

7.2.1.1.4 Environmental Control Equipment

Every boiler is assigned a pollution control strategy depending upon combustor type, size, and location (see Section 6). The required emission standards are translated into four pollution control strategies specifying a unique combination of equipment and coal quality.

Particulate emission control is necessary when burning any kind of coal, regardless of the sulfur content and, in certain instances, for heavy oil firing. Particulate control generally can be achieved with ESP's, fabric filters, cyclones, and wet or dry scrubbers. ESP's have been assumed to be the type of control equipment used for the following reasons:

- Stringent limits for particulate emissions are assumed. Cyclones are not capable of the level of control currently required in many areas.
- ESP's represent the principal commercial high-efficiency particulate control technology.^{3/}

Sulfur emission limits can be satisfied using low sulfur coal or residual oil, FGD devices (scrubbers), or some combination of the two. There are several major types of FGD systems which differ depending upon particulate removal capability, the type of chemical reagent (lime- or sodium-based) used, whether the chemical reagent is regenerated or disposed of, and whether the FGD system uses purchased chemicals or an appropriate alkaline stream from a production processing operation.

FGD costs are based on a purchased chemical, regenerative sodium-based system which generates a semisolid sludge. This system, applicable to all industrial installations, achieves a high degree of SO₂ and particulate removal efficiency.^{4/} Sludge removal costs are considered an operating expense. Use of this system will overstate the costs of using coal in plants in which the much cheaper process waste stream FGD system (one-third to one-half as expensive) would be applied, as in some Kraft paper processing operations.

Section 6 outlines the various strategies used to meet NSPS and/or SIP standards. In the examples that appear later in this section, it is assumed that both residual oil- and coal-fired combustors will use high sulfur fuel in conjunction with both ESP and FGD systems so as to meet the strictest proposed standards.

7.2.1.1.5 Powerhouse

The costs of a powerhouse are higher for a coal-fired boiler because the boiler is larger than that which fires oil or gas. Powerhouse costs for coal use are based on the size of the required building plus storage bunkers.

7.2.1.1.6 Site Preparation Offsite Utilities

Coal-fired installations require more extensive utilities because of coal and ash handling equipment. Costs include an electrical substation plus extension of rail and water lines to the site.

7.2.1.1.7 Other Working Capital

In addition to the fuel storage costs covered in fuel handling, two months of O&M expenses are assumed to be required as working capital.

7.2.1.1.8 Engineering and Contingency Costs

Engineering costs plus a contingency reserve for capital expense also are included based on standard rules of thumb.

7.2.1.1.9 Other Costs

There are other cost elements, such as feedwater treatment and general and administrative expenses, which do not vary significantly by the fuel selected. These costs are included in the overall capital costs, but will not have a significant impact on the cost difference between fuel types.

7.2.1.2 Existing Boiler Capital Costs

Costs for converting existing boilers from one fuel to another are calculated for two classes of existing boilers: those originally designed to fire coal that currently are using oil or gas, and those originally designed to fire only oil or gas. Conversion to any fuel but coal will have the same costs in both classes. Conversion costs between the two classes differ only for coal use.

The cost of converting coal-capable boilers (those originally designed to fire coal) is related to the operational status of equipment needed to burn coal. When the boiler already is using some coal, conversion can simply entail eliminating further oil or gas use. At the other extreme, conver-

sion of boilers that never actually fired coal would require installing pollution control and all coal-related auxiliary equipment.

Retrofit costs for conversions from gas, residual oil, or distillate oil to gas, residual or distillate oil, or coal were evaluated for nine unique retrofit combinations developed in-house. For more details, see Appendices H and I.

For existing boilers designed to fire only oil or gas, coal conversion implies accelerating the retirement of existing boilers and installing new coal-fired boilers, a process less expensive than retrofitting or modifying the original boilers. Thus, the costs for converting this class of boilers from oil or gas to coal use are the same as new coal-fired boiler costs.

7.2.1.3 Capital Costs for Process Heat Applications

Fuel-related equipment requirements for process heaters vary for each specific application and type of heater or furnace. Consequently, it is not possible to develop generic costs similar to those developed for boilers. Equipment requirements were classified into three categories: combustor-related, auxiliary (e.g., fuel handling), and environmental control. Boiler costs for the last two categories are assumed to apply to process heater costs, except that some components of the boiler category (e.g., pulverizers) are added to auxiliary equipment costs since such components would be required for coal-fired process heaters. Costs for coal-fired combustors for most process heat uses judged technically able to burn coal are highly speculative because such units have not been designed or used commercially. These costs are based on discussions with vendors and fuel users and must be regarded as ballpark estimates. The capital costs used for major processes are contained in Appendix I.

7.2.1.4 Capital Costs by Type of Combustor

Capital costs differ significantly for the four classes of combustors shown in Table 7.1. The difference between capital costs for coal and those for

TABLE 7.1 CAPITAL COST COMPONENTS AND ILLUSTRATIVE COSTS
BY COMBUSTOR CLASS

<u>Combustor Class</u>	<u>Capital Cost Component</u>	<u>Relevant to Boilers</u>	<u>Relevant to Nonboilers</u>
1. Existing coal-capable	Retrofit capital costs for all fuels	x	
2. Existing designed to fire scarce fuels; retrofit possible	Retrofit capital costs for all fuels		x
3. Existing designed to fire scarce fuels; retrofit to coal not possible	Full coal capital costs; retrofit oil and gas costs	x	x
4. New facility	Capital costs of a new fuel system	x	x

gas or oil generally is lowest for existing units designed to fire coal, next lowest for new boilers, and highest for accelerated replacement of existing oil- and gas-fired boilers. See Appendices H and I for specific examples.

7.2.2 Operating Costs -- Non-Fuel

Operation and maintenance costs (exclusive of fuel) include costs related to the combustor, environmental controls, and fuel handling. O&M costs are examined only for boilers; it was beyond the scope of this study to check O&M costs on a process-by-process basis. Boiler operating costs were assumed to be applicable to process heat applications. Details and supporting data sources are contained in Appendix H.

7.2.2.1 Boiler Operating Costs

Boiler operating costs have two major components: materials and labor. Labor is assumed to be a constant cost independent of boiler size. Materials cost, on the other hand, depends on boiler size and is assumed to be a constant percentage of capital costs.

7.2.2.2 Environmental Control Operating Costs

In order to control particulate emissions caused by burning coal, ESP's often are used. The O&M cost for an ESP is a function of both capacity and "uptime" of the boiler. The ESP O&M costs also reflect economies of scale.

Coal burning also often requires FGD systems to reduce the sulfur content of flue gas. FGD systems also can control particulate emissions. The O&M cost for an FGD system includes estimates for water, chemicals, personnel, electricity, maintenance, and solid waste disposal requirements. The cost reflects economies of scale as a function of boiler size and capacity utilization.

7.2.2.3 Fuel Preparation Costs

Coal and oil handling costs are described in Appendix H by volume class size. Data for this section of the O&M costs were derived predominantly from discussions with vendors. Fuel handling costs generally are plant-specific. The number of people involved in unloading, storing, and reclaiming fuel depends on the individual level of automation and the annual fuel demand at each plant. As a result, economies of scale associated with large plants are not captured in this boiler-by-boiler analysis.

Ash handling O&M costs are estimated for two components: costs of the ash handling equipment and costs associated with ash disposal.

7.2.2.4 Property Tax

The property tax component is estimated as two percent of the initial capital investment. This tax is an annual operating cost which is added to the fuel costs and non-fuel O&M expenses.

7.2.2.5 Caveats and Issues with Operating Costs

The O&M costs presented above are based on fuel use in boilers. These O&M costs are assumed to apply to process heat costs. In general, this assumption should be a reasonable one since the same requirements for labor, auxiliary equipment, fuel handling, and environmental control should apply to both boilers and process heaters.

It should be emphasized that, while the O&M costs used are believed to be "typical," these costs can vary tremendously. For example, actual costs depend on operating conditions, e.g., whether or not a firm wants to trade off extended combustor use for higher maintenance costs. If the firm decides to "run the combustor to the ground," then the O&M costs will be quite small as compared to an equal sized unit with a much longer projected lifetime.

7.2.3 Sample Costs

Table 7.2 presents cost estimates for a residual oil-fired boiler. The boiler is rated to fire at 175 MMBtu/hr input, and capacity utilization is assumed to be 65 percent. High sulfur oil is presumed to be the fuel source and both FGD and ESP are included in the cost estimates to meet the strictest environmental regulations.

The pollution control and boiler equipment comprise most of the overall cost of a new unit. The importance of the FGD system is reflected by its cost -- 45 percent of total capital costs and over 55 percent of non-fuel operating costs. Whether or not an FGD is necessary for a given fuel significantly impacts the overall fuel choice decision.

Tables detailing costs for other fuel types, boiler sizes, and existing boiler conversions are provided in Appendix H. Appendix I presents similar data for process heat applications.

7.2.4 Fuel Costs

Fuel costs significantly affect fuel choice decisions because they contribute more to the total annualized cost of a unit (see Table 7.7) than do capital or annual non-fuel O&M expenses and account for regional variations in fuel choice decisions for similar units. Coal, for example, will be selected only if fuel cost savings will be sufficient to offset the higher capital and operating costs associated with coal utilization.

Projected regional fuel prices are exogenous inputs to IFCAM. The primary source is MEFS. In cases when IFCAM output showed a significantly different fuel mix from MEFS, MEFS has been rerun with a different set of energy demands to arrive at a "better" set of fuel price projections which are more consistent with the IFCAM fuel mix. The derivation of the fuel prices for the sample run is presented in Appendix L. This section will focus on the key issues associated with fuel price projections.

TABLE 7.2 SAMPLE BOILER COSTS
(10³ \$ 1975)

Firing rate: 175 MMBtu/hr

Capacity utilization: 65 percent

Location: Northeast

Fuel type: High sulfur residual oil

<u>Component</u>	<u>Capital Cost</u>	<u>Operating Cost</u>
Boiler	843	127
Feedwater	375	-
Powerhouse	250	-
Fuel handling	52	19
Pollution control ^{a/}		
ESP	633	85
FGD	1949	427
Total direct cost	4102	658
Offsite utilities (10%)	410	
Engineering (10%)	451	
Contingency (20%)	993	
Total	1854	
Property tax	-	119
Working capital	130	-
Fuel stockpile ^{b/}	144	-
TOTAL COST	6230	777

a/ Stringent pollution control regulations were assumed, requiring both FGD and ESP.

b/ Based on a fuel cost of \$2.50/MMBtu.

7.2.4.1 Fuel Types

IFCAM uses six fuel types:

- Natural gas.
- Distillate fuel oil.
- High sulfur residual fuel oil (more than 2.0 lbs SO₂/MMBtu).
- Low sulfur residual fuel oil.
- High sulfur coal (highest sulfur coal available, usually greater than 5.0 lbs SO₂/MMBtu).
- Low sulfur coal (less than 1.2 lbs SO₂/MMBtu).

In addition, there may be two types of natural gas prices. "Average" gas prices refer to interstate supplies or to an average of old and new contracts in the major gas supply regions (Southwest and Central). "Marginal" gas prices represent direct sales of new gas by intrastate pipelines to industry. Marginal gas prices do not include a distribution company markup and are not affected by the incremental pricing provisions of the Natural Gas Policy Act of 1978. Marginal prices apply to new combustors and to existing combustors retrofitting to gas in the Southwest and Central regions. It is assumed that new customers will attempt to purchase gas supplies at the least cost. However, not all new customers will have access to marginally priced gas supplies due either to their location or their small size.

Distillate and residual fuel oil prices are wholesale (city gate) prices. These prices may understate oil costs to the extent that industrial users do not qualify for large lot discounts and must pay retail prices.

MEFS projects an average residual oil price for all grades and does not distinguish between high and low sulfur fuel types. A categorization of fuel by sulfur content, however, is important because there is a significant price premium associated with low sulfur fuel oil. The price given for an average residual fuel oil is too expensive for the boiler in which environmental regulations permit the burning of high sulfur residual fuel oil without a scrubber to control SO₂ emissions. The price also is not representa-

tive for boilers which must scrub high sulfur residual fuel oil or burn low sulfur residual fuel oil to comply with environmental standards.

Residual fuel oil prices in this analysis are keyed off of the regional distillate fuel oil prices. In a market equilibrium, residual fuel oil prices should differ from distillate oil prices because of a "form" (or value in use) and a sulfur premium. The form premium reflects the relative costs of transporting, storing, and burning fuel products. Residual fuel oil has a lower form value relative to distillate oil for the following reasons:

- It must be heated when transported or stored in order to facilitate pumping.
- It takes longer to combust than distillate oil because its larger droplet size, due to its higher viscosity, increases vaporization time, and higher temperatures are required to crack heavy oil molecules into smaller molecules which then vaporize;^{5/} residual-fired furnaces must be larger than distillate-fired furnaces for the same heat release.

This form premium has been estimated at \$0.14/MMBtu.^{6/} Since both low sulfur residual and distillate oils can satisfy environmental restrictions, the price of these two fuels should differ by the form premium.

High sulfur residual oil should command a lower price, depending on the cost of desulfurization at the refinery. This sulfur premium represents the desulfurization cost differential between an average sulfur content oil (associated with the average sulfur content of the state regulations set pursuant to the Clean Air Act) and low sulfur oil.^{7/} The price of low sulfur residual oil was reduced by \$0.33/MMBtu (1975 dollars) in order to estimate the price of high sulfur residual oil.

Coal prices to the industrial sector are the sum of FOB mine prices plus transportation costs. For each demand region and coal type (high and low sulfur), a representative supply center is identified. FOB mine prices are estimated to be the first year price of coal for the marginal new mine in each supply region.

Transportation costs are based on single-car rail rates applicable to actual distances between the coal supply centers and a centroid delivery point within each of the 10 demand regions. This method of calculating transportation costs will tend to overstate delivered coal prices in cases in which:

- Plants are located near navigable waterways and barge deliveries are less expensive.
- Coal volumes are sufficient to justify multiple-car or annual volume discounts.
- Plants are located near demand region boundaries and are closer to supply centers than the chosen demand region centroid.

Transportation charges will be understated for those plants located near the regional boundary opposite the supply region centroid.

7.2.4.2 Projection Methodology

It is difficult for industrial energy managers to forecast price projections accurately. Different managers develop different scenarios and time periods for price forecasts. Some managers make forecasts based on short-range expectations because they lack the confidence to make expensive capital investment decisions based on a long-range price projection. If the economics are not favorable in the near term, then the investment may not be prudent at this time. Some forecasts explicitly forecast prices by fuel type only over a near term time horizon (e.g., through 1985 or 1990). Since fuel price projections beyond that time frame are even more conjectural, fuel prices beyond 1985 or 1990 may be kept constant in real dollars.

The model has been used with basically three classes of fuel price expectation scenarios. One scenario, which might be called "perfect foresight," assumes the fuel price projections are used for the remaining useful equipment lives. A second method is a "limited foresight" scenario in which fuel price forecasts are used through 1985-1990; forecasts beyond that time frame are frozen at constant real prices. A third scenario simply shortens the time horizon for the investment decision period (e.g., from 30 to 10 years)

over which fuel costs would be taken. Generally, the latter two methods tend to generate higher costs for the coal option by reducing fuel savings in the out years.

In past uses of the model, the primary source for fuel price projections is MEFS. In general, 1985, 1990, and 1995 prices are derived from MEFS output. Compound annual growth rates are assumed to be applicable for intermediate years and average 1985-1995 or 1990-1995 compound annual growth rates are used to forecast increases in fuel prices after 1995. There may be upper limits on the extent of possible increases in fuel prices. For example, gas prices may be restricted to increase to the price of an alternate fuel, then escalate with the alternate fuel price.^{8/} Oil prices may be constrained to rise only to \$x/bbl and remain constant (in real terms) after that time.

MEFS data are used directly to calculate regional average retail gas prices and wholesale distillate prices. Marginal gas prices are estimated using MEFS data on regional intrastate gas wellhead prices. Residual fuel oil prices are derived by subtracting the form and sulfur premiums discussed earlier from the distillate prices.

MEFS projects delivered industrial prices for low and medium sulfur coal. However, these prices are inappropriate for this analysis for several reasons.

- FOB mine prices are 30-year annuity prices for the marginal new mine in a certain supply region and do not represent first year prices. IFCAM uses a projection of first year prices to calculate unique annuity fuel costs depending on the remaining useful life of each combustor.
- MEFS coal transportation costs are unit train rates plus a national average single-car rate premium (R2.50/ton) plus a surcharge (\$5.50/ton).
- High sulfur coal is confined to the utility market in MEFS.

Therefore, the current approach for projecting coal price increases is to:

- Identify the primary supply region for each demand region and coal type in MEFS.
- Estimate the appropriate 30-year annuity price from MEFS coal supply curves and convert it to a first year contract price.
- Add single-car rail rates and increase these transportation costs at one percent per year.

7.3 INVESTMENT DECISION APPROACH

7.3.1 Decision Criteria

The fuel choice decision framework in IFCAM is based on the premise that industry will try to minimize the total costs of generating energy over the useful life of the facility. Specifically, decision-makers will tend to select that fuel which has the lowest after-tax NPV of the cash outflows for operating and capital costs.

In addition to this standard decision criterion, industrial fuel users will weigh two other key factors. The first is the reliability of alternative energy supplies. While energy costs often comprise a relatively small share of total costs (five to 10 percent), a reliable energy supply is critical to maintaining production process flows. Given equal or nearly equal costs of alternative fuels, industry will choose the fuel perceived to be more reliable. Reliability relates to the security of fuel supply deliveries, fuel quality, environmental regulatory delays, uncertainties regarding required environmental control costs, and routine operating problems. These factors frequently are referred to as "hassle" factors. In some model runs, the hassle factor is added explicitly to costs by increasing delivered coal prices by a fixed percentage (e.g., 10 percent or approximately \$0.15-20/MMBtu).

The other key element in the investment decision framework considers whether the capital investment is discretionary or required. Investment decisions.

invariably are made in a capital constrained environment. Consequently, decision-makers will rank their investments as follows: those required by law (e.g., environmental), those essential for maintaining current production (or current market share), and those related to new market opportunities and other discretionary investments. A new boiler associated with a production facility expansion would be a required investment. The voluntary replacement of a gas-fired boiler with a new coal-fired boiler to reduce costs would be a discretionary investment not necessary for production or sales goals.* Since such discretionary investments will receive a lower priority in the corporate budget, IFCAM requires a relatively higher rate of return for discretionary energy investments than it does for required investments.

7.3.2 Overview of NPV Calculations

A conventional NPV approach is used to calculate the total after-tax cost of energy. The components of this calculation, using oil as an example fuel, include: ,

- PO_t - the cost of fuel oil burned in the facility in year t
- OC_t - the operating costs of using oil in year t
- OK_t - the capital cost of the oil facility in year t
- D_t - depreciation expense on capital in year t
- e - the share of capital cost which can be expensed (does not form the base for capital depreciation)
- S - the share of capital costs eligible for an ITC
- T - the corporate income tax rate
- ITC - the allowable percentage investment tax credit
- i - the discount rate

* Installation of oil firing capability, however, may be viewed as an essential investment because of expected gas curtailments.

UL - the useful life of the investment

CP - the construction period for the facility

L - the life used for the NPV calculation (where $L=UL+CP$)

The following illustrates how these components are used to determine the present value of energy costs for oil.

$$NPV(\text{oil}) = \sum_{t=1}^L \frac{(1-T)(-PO_t - OC_t - D_t - eOK_t) + D_t - (1-e)OK_t + S(1-e)(OK_t)(ITC)}{(1+i)^t}$$

The decision to select residual oil, for example, will be made if:

$$NPV(\text{resid.}) > \max \{ NPV(\text{gas}), NPV(\text{dist.}), NPV(\text{coal}) \}$$

7.3.3 Components of NPV Calculation

7.3.3.1 Fuel Prices, Operating Costs, and Capital Costs

For a discussion of the derivation of fuel and combustor type specific costs, please refer to previous portions of this section.

7.3.3.2 Expensible Construction Costs

A portion (10 percent) of equipment and facility construction costs are considered expensible in the model. These expensible costs, allowable deductions for income tax purposes, are excluded from the depreciable capital cost. Expensible costs normally are higher than initial engineering costs. They can vary for each case depending on the amount of work done in-house and the portion of turnkey costs (i.e., total package delivered to the fuel user). The estimate that 10 percent of construction costs are expensible is assumed to be typical, based on discussions with equipment vendors.

7.3.3.3 Construction Period

This period refers to the interval when capital expenditures are being incurred for facility construction and no fuel is being burned. This period

is assumed to be two years for all boilers and one-two years for process heaters, depending upon the particular application. Although package boilers can be installed more rapidly than field-erected boilers, the bias introduced by the longer construction period of field-erected boilers is offset roughly by the shorter useful life of package boilers.^{9/}

7.3.3.4 Depreciation

Depreciation can be calculated using straight line, sum-of-years digits, or declining balance methods. Generally, model runs have used sum-of-years digits. The model operates so that depreciation methods can differ by fuel type in order to analyze policy options which require straight line depreciation for oil and gas facilities and more accelerated methods for coal facilities.

The depreciable life for new boilers is 28 years per IRS guidelines. Depreciable life also can be varied by fuel type to analyze the proposals. For existing boilers, depreciable life is set equal to remaining useful life. Depreciable lives for process heat equipment are based on the "asset guideline period" which applied to specific industrial application.^{10/}

7.3.3.5 Share of Investment Cost Eligible for Tax Credits

Current ITC rules allow an ITC only on certain items of capital costs (e.g., land and buildings are not eligible). Shares of capital expense eligible for the ITC are determined by fuel type. On certain policy options, defining the share of coal-related investments is itself an issue. IFCAM allows for a single share for boilers and differentiates by fuel type. The share of allowable costs for process heaters is specific to the process. Since only fuel-related costs such as pollution control, fuel handling, burners, pulverizers, and sootblowers are eligible for special tax credits in certain policy options, the share of capital costs eligible for an ITC tends to be much lower for process heaters (40-60 percent) than for boilers (75-90 percent of costs). The distinction is important since

a provision to allow a special ITC for coal-related capital is a much weaker economic incentive for process heaters than for boilers.

7.3.3.6 Investment Tax Credit

The baseline rule is the current 10 percent ITC. The ITC rate is distinguished by fuel type in order to analyze specific policy options such as the elimination of any ITC for new oil- and gas-fired boilers.

7.3.3.7 Corporate Tax Rate

A tax rate of 48 percent is used to reflect the marginal corporate tax rate for investment decisions. This assumes that corporations' earnings are sufficient to make this maximum tax rate relevant for fuel choice decisions.

7.3.3.8 Discount Rate

The discount rate represents the hurdle rate or required return on an investment. Traditionally, the required rate of return simply has meant the cost of capital. If an investment does not pay for itself plus the charges incurred to finance the project, a firm is better off not making the investment. In this analysis, the average cost of capital and an investment priority scheme are accounted for explicitly.

The basic component of the discount rate used in this analysis represents the overall cost of capital to industry. This cost includes two principal components: long-term debt and equity. The long-term debt portion, valued at 10 percent, is based on typical industrial bond yields over the past few years. The cost of equity is not determined in as straightforward a manner. Conceptually, this cost is the opportunity cost of holding equity, valued at the amount all of a firm's shareholders would have earned had they invested their funds elsewhere. Management will represent the interests of current stockholders by requiring a return that will provide earnings adequate to pay out dividends and reinvest to insure stock appreciation. Interviews with industrial financial decision-makers show that a range of

12-15 percent commonly is used in actual investment decisions. Although no single value was agreed upon, 15 percent was mentioned more often than any other number.^{11/} Thus, 15 percent is used as the return on equity.

An industry-wide average total cost of capital is determined by combining the costs of debt and equity using the industry average debt-to-equity ratio. Table 7.3 displays average long-term debt/total capital ratios for the key industries used in this analysis. The overall ratio is 35 percent debt and 65 percent equity. The resulting weighted average before-tax nominal cost of capital is 13.3 percent. When adjusted for an inflation rate of five percent and converted to an after-tax basis, the cost of capital equals seven percent (see Table 7.4).

As discussed above, industrial investment decision-makers commonly distinguish between discretionary investments, which are intended to reduce costs, and required investments, which are intended to maintain or expand market share or to fulfill legal obligations. According to these definitions, investments to accelerate the rate of replacing existing oil- and gas-fired units with coal units or of converting existing units designed to fire coal to achieve cost savings are classified as discretionary. Production could be maintained with the existing oil- or gas-fired combustor since the only purpose of converting to coal would be to reduce costs. In reality, the priority given to required over discretionary investment would depend on capital availability and the payback on discretionary investments, factors which vary from one company to another. The effect of this investment priority has been simulated roughly in IFCAM by raising the discount (or investment hurdle rate) by 50 percent, from seven to 10.5 percent on a real, after-tax basis. All new boiler investments thus are compared against the seven percent hurdle rate while investment decisions regarding existing facilities must pass the more stringent 10.5 percent rate of return.

TABLE 7.3 LONG-TERM DEBT/CAPITAL RATIO, BY MAJOR INDUSTRY CATEGORY

Food processing	0.34
Textiles	0.32
Paper and forest products	0.38
Chemicals	0.38
Petroleum	0.37
Cement	0.43
Steel	0.37

SOURCE: The Value Line Data Bases (Arnold Bernhard and Company, Inc.: New York, New York). Data are relevant for 1976.

TABLE 7.4 DERIVATION OF DISCOUNT RATES

Cost of debt, nominal, before tax	10%
Cost of debt, real, before tax ^{a/}	4.8%
Cost of debt, real, after tax	2.4%
Cost of equity, nominal	15%
Cost of equity, real	9.5%
Industry average debt/equity split	35%/65%
Resulting nominal before-tax cost of capital for mainstream investments	13.3%
Resulting real after-tax cost of capital for mainstream investments	7%

^{a/} Annual inflation rate of five percent assumed.

7.3.4 Sample Calculation

In this subsection, a sample calculation is presented to illustrate the model's approach in simulating investment decisions. The cost data are summarized, an example NPV calculation is performed, and investment alternatives are compared.

A new 175 MMBtu/hr boiler with a 65 percent capacity utilization rate was chosen for this sample comparison. Table 7.5 presents the capital and annual non-fuel O&M expenses by fuel type. In this example, a stringent environmental regulation is assumed which requires a high degree of sulfur and particulate emissions control. Therefore, the costs of an FGD and an ESP are included in the total expenses for a residual oil or coal boiler. The model operates with all cost data (capital, O&M, and fuel expenses) expressed as 1975 dollars/annual MMBtu consumed. Table 7.5 illustrates the fact that stringent environmental regulations significantly increase the cost of burning residual oil or coal in comparison with natural gas or distillate oil.

The next step is to input a stream of fuel prices and calculate the total NPV for each alternative. Table 7.6 illustrates this exercise for the residual oil alternative. The fuel type is high sulfur residual oil and the fuel price projection is typical of what is used in the sample run. High sulfur residual oil is applicable in this circumstance because sulfur control is required regardless of whether or not the fuel type is high or low sulfur, and high sulfur residual oil is less expensive than low sulfur residual oil. In this example, fuel prices increased over one-half the life of a new boiler (14 years) and were held constant in real terms thereafter.*

IFCAM performs the economic analysis on an after-tax basis. Therefore, all of the annual expenses in Table 7.6 have been multiplied by $1 - \text{tax rate}$. The calculation can be divided into two time periods. The first two years

* The model is flexible in that fuel prices can remain flat, increase, or decrease during any period in the project life.

TABLE 7.5 COMPARATIVE COSTS FOR A NEW 175
MMBtu/HR BOILER^{a/}

(\$1975)

<u>Fuel Type</u>	<u>Cost Component</u> ^{b/}	<u>Total Cost</u>	
		<u>\$000</u>	<u>\$/MMBtu</u>
Natural Gas	Capital	2,072	2.079
	Operating	132	0.132
Residual Oil ^{d/}	Capital ^{e/}	6,230	6.252
	Operating ^{e/}	770	0.780
Distillate Oil	Capital	2,296	2.304
	Operating	165	0.167
Coal ^{d/}	Capital	9,390	9.423
	Operating	971	0.974

a/ See Appendix H for a detailed breakdown of cost components.

b/ Operating costs are annual non-fuel O&M expenses.

c/ $\$/\text{MMBtu} = (\$000 \times 1000) / (175 \text{ MMBtu/hr} \times 8760 \text{ hrs./yr.} \times 65\% \text{ capacity utilization})$

d/ Includes pollution control equipment: FGD and ESP.

e/ See Table 7.2 for a detailed breakdown of cost components.

TABLE 7.6 SAMPLE AFTER-TAX NPV CALCULATION FOR A NEW 175 MMBTU/HR BOILER
(1975 \$/MMBtu)

Year ^{a/}	Fuel ^{b/}	O&M ^{c/}	Depreciation ^{d/}	Expensible Construction ^{e/}	Capital Investment	ITC ^{f/}	Cash Flow	Discounted Cash Flow ^{g/}	Cumulative NPV
1	-	-	-	-3.13	-2.813	0.253	-2.873	-2.873	-2.873
2	-	-	-	-3.13	-2.813	0.253	-2.560	-2.393	-5.266
3	-1.045	-0.390	0.194	-	-	-	-1.241	-1.084	-6.349
4	-1.045	-0.390	0.187	-	-	-	-1.248	-1.019	-7.368
5	-1.045	-0.390	0.180	-	-	-	-1.255	-0.957	-8.325
6	-1.045	-0.390	0.173	-	-	-	-1.262	-0.900	-9.225
7	-1.045	-0.390	0.167	-	-	-	-1.268	-0.845	-10.070
8	-1.045	-0.390	0.160	-	-	-	-1.275	-0.794	-10.864
9	-1.185	-0.390	0.153	-	-	-	-1.422	-0.828	-11.692
10	-1.234	-0.390	0.146	-	-	-	-1.478	-0.804	-12.496
11	-1.285	-0.390	0.139	-	-	-	-1.536	-0.781	-13.277
12	-1.320	-0.390	0.132	-	-	-	-1.578	-0.750	-14.026
13	-1.355	-0.390	0.125	-	-	-	-1.620	-0.719	-14.746
14	-1.391	-0.390	0.118	-	-	-	-1.663	-0.690	-15.436
15	-1.428	-0.390	0.111	-	-	-	-1.707	-0.662	-16.098
16	-1.466	-0.390	0.104	-	-	-	-1.752	-0.635	-16.733
17	-1.504	-0.390	0.097	-	-	-	-1.797	-0.609	-17.341
18	-1.504	-0.390	0.090	-	-	-	-1.804	-0.571	-17.912
19	-1.504	-0.390	0.083	-	-	-	-1.811	-0.536	-18.448
20	-1.504	-0.390	0.076	-	-	-	-1.818	-0.503	-18.951
21	-1.504	-0.390	0.070	-	-	-	-1.824	-0.471	-19.422
22	-1.504	-0.390	0.063	-	-	-	-1.831	-0.442	-19.864
23	-1.504	-0.390	0.056	-	-	-	-1.838	-0.415	-20.279
24	-1.504	-0.390	0.049	-	-	-	-1.845	-0.389	-20.669
25	-1.504	-0.390	0.042	-	-	-	-1.852	-0.365	-21.034
26	-1.504	-0.390	0.035	-	-	-	-1.859	-0.343	-21.376
27	-1.504	-0.390	0.028	-	-	-	-1.866	-0.321	-21.698
28	-1.504	-0.390	0.021	-	-	-	-1.873	-0.301	-21.999
29	-1.504	-0.390	0.014	-	-	-	-1.880	-0.283	-22.282
30	-1.504	-0.390	0.007	-	-	-	-1.887	-0.265	-22.547

a/ Year 1 = 1980.

b/ Price forecast is similar to fuel price projections for high sulfur residual oil in the sample run.

c/ Annual O&M expenses do not increase in real terms.

d/ Sum-of-years digit method. Depreciates capital investment over 28 years. Equals $(1 - \text{tax rate})(-D_t) + D_t$, where t is the year (see Section 7.3.2).

e/ 10 percent of total capital cost.

f/ Nine percent of capital investment (see Section 7.3.3.5).

g/ Discount rate is seven percent.

cover the construction phase and include the capital investment and the ITC's. The last 28 years of the calculation capture the operating costs and depreciation credits of the on-line unit.

Since no revenues are considered in the calculation and no comparison is made to an alternative unit at this point, the resultant cumulative NPV is negative. This figure then is compared to those resulting from calculations of the other fuel type alternatives; the fuel type chosen is the one whose cumulative NPV is closest to zero (i.e., has the smallest absolute value).

Table 7.7 presents the NPV result for each of four fuel types (note that the residual oil and coal units include pollution control equipment and use high sulfur fuel). The fuel having the least negative NPV is natural gas; distillate oil is the runner-up.

7.3.5 Annualized Cost Comparison

To understand how the three cost elements discussed previously (capital, operating, and fuel costs) affect the fuel choice decision, it is necessary to see their relative importance in determining the overall cost of a fuel burning unit. To do this, the cost components are placed on a common basis. One method of achieving this is to annualize the present value of the components spread over the life of the unit.

Tables 7.8 and 7.9 present annualized costs for a 175 MMBtu/hr boiler for four fuel types. These costs are consistent with the examples presented in Tables 7.5 and 7.7. Table 7.8 shows the comparison in terms of 1975 \$/MMBtu (units used in IFCAM). Table 7.9 shows equivalent costs expressed as 1978 \$/lb of steam (which may be more familiar to the reader).

The annualized costs, presented on a pre-tax basis, reveal the important role that fuel prices play in the fuel choice decision. For each fuel

TABLE 7.7 NPV COMPARISON FOR A NEW
175 MMBtu/HR BOILER

(1975 \$/MMBtu)

<u>Fuel Type</u>	<u>Total NPV^{a/}</u>	<u>Rank</u>
Natural Gas	-19.541	1
Residual Oil ^{b/}	-22.543	3
Distillate Oil	-19.663	2
Coal ^{b/}	-22.643	4

a/ After-tax values (including capital, ORM, and fuel) assuming:
Discount rate = 7 percent
Depreciation = sum-of-years digits over 28 years
Tax rate = 50 percent (for clarity and ease of
computation)

b/ High sulfur fuel with a FGD and an ESP.

TABLE 7.8 ANNUALIZED COST COMPARISON
FOR A NEW 175 MMBtu/HR BOILER^{a/}

(1975 \$/MMBtu)

<u>Cost Component</u>	<u>Natural Gas</u>	<u>Residual Oil</u>	<u>Distillate Oil</u>	<u>Coal</u>
Capital:				
Boiler-related	0.202	0.236	0.236	0.544
Pollution control ^{b/}	-	0.372	-	0.372
O&M: ^{c/}				
Boiler-related	0.120	0.156	0.152	0.332
Pollution control ^{b/}	-	0.558	-	0.558
Fuel	2.828	2.322 ^{d/}	2.782	1.844 ^{d/}
Total	3.150	3.644	3.170	3.650

a/ Pre-tax calculation

b/ Includes a FGD and an ESP

c/ Assumes a 65 percent capacity utilization

d/ High sulfur fuel type

TABLE 7.9 ANNUALIZED COST COMPARISON
FOR A NEW 175 MMBtu/HR BOILER^{a/}

(\$ 1978/lb. of steam)^{b/}

<u>Cost Component</u>	<u>Natural Gas</u>	<u>Residual Oil</u>	<u>Distillate Oil</u>	<u>Coal</u>
Capital:				
Boiler-related	0.32	0.38	0.38	0.87
Pollution control ^{c/}	-	0.59	-	0.59
O&M: ^{d/}				
Boiler-related	0.19	0.25	0.24	0.53
Pollution control ^{c/}	-	0.89	-	0.89
Fuel	4.50	3.69 ^{e/}	4.42	2.93 ^{e/}
Total	5.01	5.80	5.04	5.81

a/ Pre-tax calculation

b/ Assuming: annual inflation rate = 5.6 percent
1200 MMBtu/lb. of steam
89 percent efficiency

c/ Includes a FGD and an ESP

d/ Assumes a 65 percent capacity utilization

e/ High sulfur fuel type

type, the cost of fuel comprises more than 50 percent of overall costs; for gas and distillate oil, which require no pollution control equipment, fuel use over the life of the boiler makes up nearly 90 percent of total cost on an annualized basis.

Thus, while coal capital and nonfuel operating costs are much higher than those for the other fuel types, the very large savings in fuel expenses compensate somewhat for this difference. For example, coal non-fuel costs are \$1.42/MMBtu higher than those for distillate fuel oil. Coal fuel costs, are \$0.94/MMBtu less on an annualized basis. The role that fuel costs play, however, directly relates to the size of the unit. If a 50 MMBtu/hr unit had been considered instead of a 175 MMBtu/hr unit, the importance of the fuel component would have been reduced substantially, thus further eroding the advantages of coal use. This suggests that coal's strength lies in larger units, where its fuel savings are most pronounced relative to the capital and O&M components.

A second interesting point is brought forth in a comparison of the roles capital and non-fuel operating costs play in each fuel type. O&M expenses may be as important as the capital component on an annualized basis, since they are yearly figures. This is the case with pollution control equipment, where the capital component is less than that of the O&M.

FOOTNOTES

1. Combustor capacities can be expressed in terms of heat input (MMBtu/hr) or delivered steam (MPPH). Conversion efficiencies depend upon steam properties as well as boiler conditions. For this analysis, the conversion efficiency was assumed to be 1350-1400 Btu's of heat input per pound of delivered steam.
2. Equivalent to weekly receipts of 100 cars of 100 tons capacity each. Although fuel use in industrial plants is not large enough to justify unit train delivery, it is possible for plants to join together for unit trains or for a local distributor to set up unit trains for delivery to a central distribution point. The failure to include such provisions tends to overstate the cost of using coal in this analysis.
3. NUS Corporation, "Analysis of the Prevailing and Projected Environmental Costs for Coal Conversion of Major Fuel Burning Installations," draft report prepared for FEA, October, 1976, p. 4.
4. Up to 85-95 percent for sulfur dioxide and 95-99 percent for particulate removal. For a more complete discussion of the costs and operating experience of industrial FGD systems, refer to the "Guidebook to the Applicability of Flue Gas Desulfurization for Industrial Coal-Fired Boilers," prepared by Energy and Environmental Analysis, Inc., for FEA, November 3, 1977.
5. Energy and Environmental Analysis, Inc., "The Substitution Potential of Alternative Fuels for Natural Gas in Selected Industries," prepared for the Department of Commerce, June 8, 1978, p. IV-7.
6. Sobotka and Company, Inc., "Estimated Prices of Petroleum Products in 1985," prepared for DOE, February 23, 1978.
7. Ibid.
8. This is consistent with the incremental pricing provisions of the Natural Gas Policy Act of 1978.
9. "Steam Generation - A Special Report," Power Magazine, June, 1964.
10. Internal Revenue Service, Department of the Treasury, "Tax Information on Depreciation," Publication 534, 1978 Edition.

11. Energy and Environmental Analysis, Inc., "Investment Risk Evaluation Techniques: Use in Energy-Intensive Industries and Implications for ERDA's Industrial Conservation Program," prepared for ERDA, July, 1977; and "Coal Use Economics and Problems: Interviews with Industrial Representatives," prepared for Office of Policy and Evaluation, DOE, May 31, 1978.

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