DR. 1207

DOE/RA/02625-1

POTENTIAL MARKETS FOR HIGH-BTU GAS FROM COAL

April 1980

Work Performed Under Contract No. ET-78-C-01-2625-011

Booz, Allen & Hamilton, Inc.
Energy and Environment Division
Bethesda, Maryland

MASTER

U. S. DEPARTMENT OF ENERGY

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Price: Paper Copy \$9.00
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POTENTIAL MARKETS FOR
HIGH-BTU GAS
FROM COAL

The Department of Energy
Office of Coal Resource Management
Resource Manager of High-Btu Gas

April 1980

Booz·Allen & Hamilton Inc.
BOOZ · ALLEN & HAMILTON Inc.

Energy and Environment Division

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EXECUTIVE SUMMARY

It has become increasingly clear that the energy-related dilemma facing this nation is both a long-term and deepening problem. A widespread recognition of the critical nature of our energy balance, or imbalance, evolved from the Arab Oil Embargo of 1973. The seeds of this crisis were sown in the prior decade, however, as our consumption of known energy reserves outpaced our developing of new reserves. The resultant increasing dependence on foreign energy supplies has triggered serious fuel shortages, dramatic price increases, and a pervasive sense of uncertainty and confusion throughout the country.

1. HIGH-BTU GAS OFFERS SIGNIFICANT ADVANTAGES AS AN ENERGY SOURCE

In light of our current energy-related dilemma, all potential means of deriving usable energy from coal must be examined. Coal is our most abundant energy source, and its utilization offers significant balance of payment and national security benefits. There are, unfortunately, some environmental problems associated with the direct burning of coal. Further, all elements of the current stock of energy consuming equipment are not capable of using this energy source directly.

A pipeline-quality gas can be obtained from coal with existing technology. Thus, high-Btu gas offers many of the advantages of direct coal usage, and also precludes some of the problems. High-Btu gas:

- . Makes use of our vast coal resource base
- . May be transported in an extensive existing pipeline network
- . Can be utilized with no adjustment of the equipment of conventional gas consumers
- . Releases negligible pollution at the point of consumption
- . Relies on a technology which is largely proven.

In spite of these advantages, however, there are no high-Btu gas facilities in operation in our country at this time. Given the numerous advantages of high-Btu gas, a relevant question is whether or not there is, or could be, viable markets for this energy source. This question is the focal point of this study. It has been examined on purely economic grounds from the point of view of the ultimate consumer. That is, is there a potential for sufficient residential, commercial and industrial demand from consumers who could rely on high-Btu gas and who would find it economically advantageous to do so, to warrant the construction of various high-Btu gas plants. To make this determination, a life-cycle costing methodology was employed which compared the cost of owning and operating systems fueled by high-Btu gas as opposed to some other energy source.

2. HIGH-BTU GAS CAN COMPETE FAVORABLY IN MANY REGIONS AND APPLICATIONS BY 1990

Based on the market analysis contained in this report, high-Btu gas is shown to compete favorably on the basis of economics with alternate energy sources (oil and electricity). In particular, the projected costs of owning and operating oil-fired systems are almost always higher than the comparable costs associated with gas-fired systems. The market projections, which were carried out for each of the ten Federal regions in 1990 and 1995, indicate that:

- . Eight of the ten Federal regions appear capable of supporting a 125 Million cubic feet per day (MMcfd) high-Btu gas project by 1995, seven by 1990.
- . Strongest potential markets are those of the Midwest and Mid-Atlantic regions, primarily as a result of the large quantities of oil consumed in their industrial sectors.
- . The markets of the Southwest, South Atlantic, and West are also quite large, both as a result of potential industrial oil shifts and shifts in residential electricity consumption. Shifts in electricity consumption are heavily dependent on assumptions made regarding heating equipment efficiencies. These assumptions are set out in Appendix C, and the estimated potential markets are contained in Appendix E.

- . Because of the relative ease with which industrial customers can alter fuels, combined with expectations of a continuation in oil price increases, this sector offers a large and attractive target for high-Btu gas in almost all regions.
- . The North Central and Northwest regions are unlikely potential high-Btu gas markets due to low overall energy consumption, very limited oil consumption, and low electric rates in the Northwest.

These estimates were based on an attempt to measure the maximum potential high-Btu gas markets. That is, those markets which could technically convert to gas and which would find it economically attractive to do so.

Comparisons were made under both marginal and rolled-in gas pricing assumptions. Under marginal pricing, gas consumers pay the full cost of high-Btu gas, whereas in the rolled-in case they pay a weighted average cost of gas for a supply mix which is 15 percent high-Btu gas and 85 percent natural gas.

The results of the market comparisons depend in large part on:

- . Projected high-Btu gas prices
- . Projected oil prices
- . End-use equipment efficiencies.

3. FURTHER INCREASES IN THE PRICE OF OIL WILL INCREASE THE ATTRACTIVENESS OF HIGH-BTU GAS

The model employed for the purposes of this report included oil price assumptions of \$21.50 in 1985 increasing to \$31.50 by 1995 (1978 dollars). Although these assumptions were viewed as reasonable-to-high at the start of this project, they are obviously quite low in light of recent events. However, increasing the price of oil to more current levels would only serve to increase the attractiveness of high-Btu gas, a competing product to oil.

Chapter IV provides an estimate of the tailgate cost of high-Btu gas, as well as an analysis of the sensitivity of coal gas to plant capacity, feedstock costs and costing methodologies. A cost estimate of \$4.95 per thousand cubic feet (Mcf) was derived for a Lurgi plant with a capacity of 125 MMcf per day. This estimate, which was based on an

analysis of publicly available documents and filings before the FERC, may also be somewhat dated. With respect to the sensitivity analysis:

- . Pricing methodology could have a significant impact on the penetration of high-Btu gas (i.e., levelized versus non-levelized pricing)
- . The tailgate cost of coal gas is very sensitive to changes in the capacity utilization factor
- . Changes in the cost of coal will have less of an impact on the tailgate cost than the other two factors.

4. ALTHOUGH THERE ARE A NUMBER OF POTENTIAL MARKETS FOR HIGH-BTU GAS, BARRIERS TO MARKET PENETRATION ARE SIGNIFICANT

In spite of the potential attractiveness of high-Btu gas as an energy source, there are a variety of barriers which act to restrict market growth. These technological, financial and institutional barriers to high-Btu gas penetration are examined in Chapter V. This analysis is based on a literature survey and interviews with numerous key industry participants. (see Appendix D for a listing).

Technological barriers are not overwhelming, as each of the individual processes involved in gasification have been demonstrated in commercial sized facilities with the exception of the coal gas methanation step. Some scale-up problems and a possibly longer than normal shakedown period are anticipated for the first facility, however.

Financial hurdles are a major constraint, in part due to the risk averse nature of potential sponsors, primarily regulated pipelines and utilities. Large front-end capital costs, up to \$2 billion, effectively mandate joint sponsorship. This large initial investment poses serious problems should the project not be completed.

Those incentives cited as being most important to overcome high-Btu gas impediments were:

- . Rolled-in pricing
- . Loan guarantees
- . Completion guarantees

I. BACKGROUND

The Resource Applications Office (RA) of the Department of Energy is actively involved in programs to increase commercial production of supplemental energy sources for natural gas.

To focus its efforts and allocate internal resources, RA evaluates technologies and the markets for them. It is clear that nearly all supplemental energy sources for natural gas will have a unit production cost in excess of that associated with natural gas produced from conventional fields. The question that prompted this study was whether higher cost gas produced from gasification of coal resources would find a market in the U.S. energy balance of the 1990's. Even though market entry of the technology might be aided by Federal programs, long-term subsidy of a technology is not considered desirable by the DOE. Moreover, not only is the competitiveness of the gas produced from high-Btu gasification projects of interest, but of equal concern are the fuels which it would displace in the marketplace. The Department of Energy is particularly interested in technologies which might supplant imported oil.

To perform such a market assessment, it was recognized that analysis would need to be made on both a sectoral and regional basis. Economic competitiveness depends upon the entire cost of the system delivering a desired output, such as space heat, paint drying, glass finishing, etc. These systems are specific to application and, thus, to market sub-segment; i.e., residential space heat, industrial cement kilns, etc. In addition, such systems vary across regions for reasons of custom, climate, and past patterns of relative fuel prices. Therefore, much of this study was devoted to a finely detailed examination of high-Btu gas in end-use applications. The results of this economic competitiveness analysis are reported in summary in Chapter II of this report. A complete set of input parameters, calculation methodology, and detailed results are presented in Appendix C for those who wish to work through the analysis or alter input assumptions for sensitivity testing.

It was recognized that the commercial attractiveness of high-Btu gas will not be determined in a vacuum, but rather in the marketplace through competition with a variety

of alternative energy sources. Thus, the future supply, demand, and price of these alternate energy sources are critical to the development of high-Btu gas.

1. A VARIATION OF DOE'S FORECASTING SYSTEM WAS USED TO PROJECT FUTURE ENERGY MARKET CONDITIONS

To determine which geographic and sectoral markets will be most susceptible to the penetration of high-Btu gas, the future overall energy framework must be analyzed. Once the price and availability of alternate fuels are ascertained, a first-cut determination can be made of the prospects for high-Btu gas. That is, regions with a relatively high level of dependence on high priced or uncertain alternate energy sources will be more likely to support high-Btu gas projects. A general energy balance model was, therefore, used to make a first-cut determination of potential target markets. This first-cut was then followed by a more rigorous and detailed examination of these potential markets.

(1) The Midterm Energy Forecasting System (MEFS) Model Provides a Useful Tool for Predicting Future Market Conditions

The Energy Information Administration (EIA) in the Department of Energy has constructed a computer model to forecast energy production, consumption and prices in the midterm (1985-1995). This modeling system, MEFS, simulates the interactions of energy suppliers and consumers in the marketplace. The MEFS model is comprised of a number of submodels: a demand model, a series of supply models, and an integrating model which brings the submodels together in a unified system. The model determines, for each region, an equilibrium situation where the supply and demand for energy are equated at some price.

The MEFS model, as modified by Booz, Allen, was felt to be the most appropriate projecting technique for the purposes of this study, particularly in order to be consistent with internal DOE forecasts. MEFS has a number of features which enhance its utility for this study:

- . The model is highly segmented, and results are given on a DOE regional basis for each fuel and sector. The ten DOE regions are depicted on the following page.

EXHIBIT I-1 Department of Energy Regions

REGIONS

1. New England	6. South West
2. New York/New Jersey	7. Central
3. Mid Atlantic	8. North Central
4. South Atlantic	9. West
5. Midwest	10. North West

- . The model may be run under a variety of scenarios regarding economic growth, recoverable resource levels, extraction costs, and the world oil price.*
 - . The model presents a static equilibrium for 1985, 1990 and 1995, and it is neither dominated by supply nor demand.
 - . Assumptions regarding Federal regulations which impact energy markets are relatively up-to-date.
- (2) Certain Modifications for the MEFS System by Booz, Allen Were Required for the Specific Purposes of This Study

The projections of future market conditions used in this study reflect in large part the MEFS projections. Projected price and consumption levels are set out in Appendices A and B, as are the growth rates in energy consumption from 1985 through 2000. The primary differences in the assumptions underlying study projections as compared to the MEFS results are:

- . The forecast period is extended to the year 2000 through an extrapolation of price and consumption trends evident from 1990 through 1995.
- . Additions to nuclear capacity have been reduced. The slower growth in nuclear capacity assumed in this study does not impact the level of electricity generation and consumption. It is assumed that the demand for electricity will be met, and conventional fuels (primarily coal) will be used to offset any shortfalls attributable to nuclear constraints.

* This part of the study was completed prior to the large scale increases in the price of OPEC oil in late 1979. Thus, total demand for petroleum products is probably too large. However, the major conclusions of the study would not be altered by higher oil prices.

- . A higher world oil price is utilized. The world oil price in the MEFS mid-price series is set at \$15.00 in 1985 and \$23.50 in 1995 (1978 dollars). Due to the severe price adjustments in the second quarter of 1979, we have used a world oil price trajectory similar to the MEFS high oil price scenario—\$21.50 in 1985, increasing to \$31.50 by 1995. In retrospect, even this adjustment appears overly conservative in light of more recent changes in the world oil market. Again, however, increases in the price of oil above those incorporated herein would serve only to increase the attractiveness of high-Btu gas.
- . Refinery fuels, feedstocks and raw materials are not included with industrial consumption.
- . The fuel consumption of the electric utility and transportation sectors are not set out. These sectors are not seen as viable markets for high-Btu gas. Only minimal amounts of gas are used in the transportation sector for compressor fuel, and the Powerplant and Industrial Fuel Use Act of 1978 mandates a severe reduction of gas for the generation of electricity by utilities.
- . An industrial surcharge on natural gas, as mandated by the incremental pricing provision of the Natural Gas Policy Act of 1978, was tied to the price of residual fuel oil and applied only to low priority boiler fuel customers. The surcharge in the MEFS model was linked to distillate oil and applied to all industrial customers.

2. THE DEMAND FORECASTS ARE DRIVEN BY A SERIES OF CRITICAL ASSUMPTIONS ABOUT THE ECONOMY AND ENERGY PRICES

The econometric forecasting of future energy demand is an inexact exercise. Problems arise due to faulty assumptions, incorrect data, and extrapolations into the future based on relationships between variables which held in the past. The two most important assumptions which impact the forecast used herein are the world oil prices and economic growth.

Variations in the world oil prices have a number of direct and indirect effects on future energy markets. Economic growth assumptions are also critical to the determination of future energy demand. The relationship between economic growth and energy demand is two-fold:

- . Increases in economic activity, or the production of goods and services, require increases in energy inputs. Increases in energy efficiency, however, may reduce the necessary energy input per unit of production.
- . Income levels tend to rise with economic activity and, thus, energy consumption patterns may be altered.

Should the actual GNP growth rate fall below forecasted levels (3.6 percent per year 1980-1985, declining to 2.9 percent per year by 1995), a downward pressure would be exerted on energy demand.

A third consideration in assessing the potential variability of forecasted demand levels is the interpretation and implementation of government regulations. The model operates under the assumption that current laws will remain unchanged and will continue to be enforced as in the present. New laws could be enacted, or old laws re-interpreted, however, which would affect both energy production and consumption. There are a number of legislative or policy issues which remain unsettled that could have an impact on high-Btu gas development.

3. THE GROWTH IN ENERGY DEMAND THROUGH THE YEAR 2000 IS FORECASTED TO DECELERATE, BUT CERTAIN REGIONAL AND SECTORAL MARKETS EXHIBIT SIGNIFICANT GROWTH POTENTIAL

The demand for energy in the sectors analyzed (residential, commercial and industrial) is projected to increase at roughly 2 percent per year through the end of this century. This rate represents a significant decline from the 3 to 4 percent growth rates experienced in the recent past. Energy consumers, faced with supply shortages and rapidly increasing prices have begun to shift their consumption patterns. Conservation efforts will continue to increase as prices are driven upward from the artificially low levels of the 1950's and 1960's. Accentuating this price-induced conservation impact will be a moderation in economic growth which will further limit energy demand. In spite of this trend of an overall slowdown, certain regions of the country and sectors of the economy are expected to exhibit significant energy growth.

Industrial energy demand is projected to increase at an annual average rate of 3 percent, nearly triple the anticipated rates of the residential and commercial sectors. It is generally felt that most of the easy options available to industrial consumers in terms of reducing fuel consumption were exercised in the more immediate post-embargo period (1973-1977). These options stressed the modification of existing capital and processes. Further reductions, however, will tend to rely on more substantial investments in new capital or operational modes. Therefore, substantial growth in energy consumption will be required to support forecasted economic growth, and further efficiency improvements will come more slowly.

Growth in residential energy demand from 1985 through 2000 will lag behind historic levels, but it will increase somewhat from the post-embargo slump as energy price increases tend to moderate. Growth in commercial energy demand is expected to be slightly less than residential growth. The hypothesis is that commercial conservation measures tend to be more expensive than residential measures and they are, therefore, implemented more slowly. Whereas a good deal of residential conservation began in the 1972-1977 period, commercial conservation will play a larger relative role in the forecast period.

The overall demand for energy in the South Atlantic and Southwest Regions is projected to increase at an annual rate of approximately 3 percent through 2000. Conversely, increases in New England, New York, New Jersey, and the mid-Atlantic will be limited to the 1 to 1.5 percent range. There is a strong correlation between projected growth rates and the composition of energy consumers. That is, regions in which the residential and commercial sectors account for greater relative shares of total energy consumption will tend to grow at a lower rate than those in which industrial consumption dominates.

4. A VARIETY OF ENERGY SOURCES WILL BE TAPPED TO SATISFY FUTURE DEMAND

The rising demand for energy will be met through the utilization of a wide range of supply sources, both conventional and unconventional in nature. As the production of domestic oil and gas declines, or at best stabilizes, alternate sources will be forced to play a greater role in the satisfaction of domestic requirements. The projected mix of sources to satisfy residential, commercial, and industrial requirements is set out in Exhibit I-2.

EXHIBIT I-2
Energy Sources Projected to Meet
Residential, Commercial and
Industrial Demand Through 2000

* SUPPLEMENTALS INCLUDE: IMPORTED OIL; ALASKAN, CANADIAN, AND MEXICAN GAS; IMPORTED LNG; OIL SHALE; COAL LIQUIDS, AND PETROLEUM AND COAL DERIVED GASES.

** CONSUMPTION EXCLUDES ENERGY CONSUMED IN THE TRANSPORTATION AND ELECTRIC UTILITY SECTORS, AS WELL AS REFINERY FUELS, FEEDSTOCKS AND RAW MATERIALS.

Source: MEFS model as adjusted by Booz, Allen.

As shown in Exhibit I-2, total energy consumption for the residential, commercial, and industrial sectors is projected to increase from 34 quadrillion Btu in 1977 to 53 quadrillion Btu in 2000. Roughly 90 percent of this increase will be met through additional usage of coal and electricity. Whereas the respective shares of coal and electricity were 11 and 20 percent of total supply in 1977, these shares are expected to reach 22 and 30 percent by 2000. Conversely, the share of oil and gas is shown to fall from nearly 70 percent in 1977 to only 50 percent by the end of the period. (Although the share of natural gas relative to total energy consumption is expected to fall, the absolute level of gas consumption may increase.) Also, gas consumption in specific sectors, e.g., residential and commercial, may continue to increase while declines are experienced in other sectors, e.g., industrial and utility.

Most increases in residential and commercial energy demand will be picked up by electricity or natural gas. Although demand in these sectors is projected to increase at a rate of only 1 percent per year through 2000, growth in the demand for electricity will average about 2.6 percent annually. Gas demand will increase at about the same rate as that of sectoral demand, while the demand for oil declines at about 2 percent per year. Thus, increases in demand for electricity and gas are attributable not only to new construction, but also to conversions of existing oil-fired installations.

It should be noted that a good portion of industrial oil and gas is consumed in units which can accommodate either of these fuels. As the energy situation shifts, the relative shares of these two fuels may respond quickly. Certain events have occurred since the model was run which tend to brighten the outlook for gas relative to oil, and the forecasted oil consumption levels may, therefore, be somewhat overstated:

- . The overall gas supply outlook is brighter, and the prospect for widespread industrial curtailments has been reduced.
- . Incremental pricing, as indicated by the Natural Gas Policy Act, will be tied to residual fuel oil rather than distillate as was previously assumed. This will have a tendency to reduce gas prices to large volume industrial customers.
- . The most recent round of substantial oil price hikes and supply uncertainties has dampened the outlook for oil products.

It is often assumed that high-Btu gas will compete only with other gaseous fuels for a share of the gas market. That is, gas demand is assumed to be constant and high-Btu gas must compete with Alaskan, Canadian, LNG, low-Btu, and medium-Btu gases. However, in the larger context of an overall energy market, high-Btu gas may be thought of as a competitor to electricity, imported oil, and other supplements. That is, the demand for gas is not fixed, but rather may fluctuate depending on its competitive position vis-a-vis alternative energy sources. As long as the rolled-in cost of gas remains competitive with alternate fuels, high-Btu gas may be added to the gaseous fuel mix. The implication of this concept is that high-Btu gas may be used to replace costly and uncertain energy sources, e.g., foreign oil, rather than displacing only other domestic gas sources, e.g., Alaskan gas or low- and medium-Btu gas. Due to significant constraints on the distances over which low- and medium-Btu gases may be economically transported, as well as to the flue and burner modifications necessitated by their consumption, these gases are not considered to be universal competitors to high-Btu gas. Comparisons between low- and medium-Btu versus high-Btu gas require site-specific analyses not undertaken for the purposes of this report.

* * * * *

This chapter has set the framework for analysis of the potential applications of high-Btu gas from coal. The following chapter presents a more in-depth examination of the specific markets in which high-Btu gas will compete.

II. END-USE ANALYSIS OF THE COMPETITIVENESS OF HIGH-BTU COAL GAS

The purpose of this chapter is to test the economic competitiveness of high-Btu gas in the residential, commercial, and industrial sectors on a regional basis. The major energy-consuming applications in these sectors have been analyzed, and the cost of owning and operating high-Btu gas-fired systems have been compared with the costs of competing systems. The evaluation tool employed was a "break-even analysis" as described below. The evaluation was undertaken for both 1990 and 1995, and comparisons were made with high-Btu gas under both rolled-in and marginal gas pricing assumptions.

1. THE METHODOLOGY USED IN CONDUCTING THE COMPETITIVE ANALYSIS WAS AN ECONOMIC EVALUATION OF ELEVEN REPRESENTATIVE APPLICATIONS

Economic comparisons of high-Btu gas in 11 representative applications, Exhibit II-1, were made using the concept of break-even prices. The break-even price is that at which the life-cycle cost of using high-Btu gas is equal to that of using the alternate fuel being evaluated; coal, oil, or electricity where appropriate. High-Btu gas is the economically attractive option when its price is less than the calculated break-even price. Exhibit II-2 is a sample break-even calculation for a coal-fired boiler versus a high-Btu gas-fired boiler in New England showing that, at a delivered gas price of \$3.05/million Btu, the costs of the two systems are identical in 1990, the year evaluated. (Full details on all of the assumptions and resulting break-even prices are included in Appendix C). The break-even analysis includes the following major variables:

- . Capital cost, and the associated carrying charge
- . Operation and maintenance cost, annualized, less fuel
- . Fuel use, for each system, in MMBtu, for a specific region
- . Fuel price, in 1978 dollars, for a specific region, in the year evaluated, in dollars per million Btu (\$/MMBtu).

EXHIBIT II-1
Representative Applications Evaluated

Residential

Single Family Dwellings

Commercial

Multifamily Dwellings

Office Buildings

Retail Stores

Schools

Industrial

Boilers

Brick Kilns

Cement Kilns

Glass Furnaces

Steel Reheat Furnaces

Food Processing Ovens

EXHIBIT II-2
Sample Break-Even Calculation

Competing System: 60,000 lb/hr industrial coal-fired boiler in Region 1, year = 1990
1978 dollars

	Competing System (Coal)	Reference System (Gas)
1. Capital cost	\$3,000,000	\$1,150,000
2. Life of system	25 years	25 years
3. Tax rate	51%	51%
4. Weighted cost of capital	11%	11%
5. Capital charge rate	.201	.201
6. Fixed carrying charge (1 x 5)	\$603,000/yr.	\$231,150/yr.
7. Operation & maintenance	\$300,000/yr.	\$115,000/yr.
8. Fuel input	579,000 MM Btu/yr.	608,000 MM Btu/yr
9. Fuel cost	\$2.24/MMBtu	—

$$\text{Break-even Price} = \frac{\$603,000 + \$300,000 + (579,000 \times \$2.24) - (\$231,150 + \$115,000)}{608,000}$$

or Break-even price - \$3.05/MM Btu

While this analysis has given the break-even price at one point in time, it should be noted that the price will change with changes in any of the other variables. For this reason, it is important to look at break-even prices over time. This analysis has evaluated the alternate systems in 1990 and 1995:

- . An earlier period would be useless to evaluate, since high-Btu gas systems will not yet be on line
- . Later periods are subject to significant uncertainty in fuel prices and equipment costs.

The 11 applications chosen represent the spectrum of primary gas uses in the residential, commercial, and industrial sectors. Over 75 percent of the gas consumed in this country is covered by these applications. It has been assumed that systems requiring only burner changes to convert from gas to oil should be evaluated strictly on a dollar per million Btu fuel cost basis, since the capital costs of conversion and operation and maintenance variations are insignificant compared to the total fuel costs. This assumption further implies that gas can be delivered to these systems through the existing pipeline network.

Following the break-even calculations, comparisons were made against the expected delivered prices of high-Btu gas in each region. Again, high-Btu gas is the preferred fuel on an economic basis when the projected high-Btu gas price is less than the break-even price. The high-Btu gas prices were calculated based on a 125 million cubic foot per day Lurgi gasifier. A full analysis of the cost components and their sensitivity to changing assumptions is included in Chapter IV. Three system configurations were selected:

- . High-Btu gas from a facility using non-caking coals sited in the West with the gas transmitted through the existing pipeline infrastructure. The gas price was rolled-in, with high-Btu gas accounting for 15 percent of the total gas supply.
- . The same system with marginally priced gas from the facility.
- . A self-contained high-Btu gas system, with its own transmission and distribution facilities, sited in Pennsylvania, with gas delivered to New England.

2. UNDER ROLLED-IN PRICING ASSUMPTIONS, HIGH-BTU GAS IS ECONOMICALLY COMPETITIVE IN MANY RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL APPLICATIONS

Under rolled-in pricing assumptions, when high-Btu gas from a centrally located, mine-mouth plant is 15 percent of the delivered gas volume, the breakeven analysis shows that economically attractive applications can be found in every region of the country. That is, when consumers are charged the weighted average cost of all gas, of which total high-Btu gas represents 15 percent, the average cost often falls below the comparable break-even price.

(1) High-Btu Gas Is Highly Competitive in the Residential Sector

High-Btu gas is economically attractive in nearly all of the ten DOE regions for residential space heating in the 1990-1995 time period. Exhibit II-3 graphically illustrates the regional competitiveness of high-Btu gas (HBG) in 1990 under different pricing assumptions, while Exhibit II-4 treats this data for 1995. The solid dots indicate applications where HBG can compete on a marginal price basis, where the end user is required to pay the full expected price. The half-filled dots show where HBG is economically attractive only when rolled-in pricing is used; i.e., where the end user pays the weighted average cost of 85 percent natural gas and 15 percent high-Btu gas in this example. The attractive areas for rolled-in pricing analysis include both the full and half-full dots, since the rolled-in price is lower than the marginal price in all cases. On a rolled-in basis, HBG is competitive with the electric heat pump in all regions but Region 10. Electric rates are unusually low in this region due to relatively cheap hydroelectric power. HBG clearly competes with oil forced air heat in all regions and is competitive with electric resistance heat in all but Region 10. In fact, HBG is shown to be favored over oil in all regions and over electric resistance heat in eight regions, even under marginal pricing assumptions. Over time, the economics of HBG grow even more favorable as residential oil and electricity prices rise faster than high-Btu gas costs.

EXHIBIT 11-3
Sector: Residential/Commercial
Year: 1990

SECTOR: RESIDENTIAL/COMMERCIAL Year: 1990

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
<u>RESIDENTIAL</u> SINGLE FAMILY DWELLINGS: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	●
<u>COMMERCIAL</u> MULTIFAMILY DWELLINGS: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ●	● ●	● ●	●	●	●	●	●	●	●
OFFICE BUILDINGS: .ELECTRIC HEAT PUMP .OIL HYDRONIC HEAT	N/A ●	N/A ●	N/A ●	●	N/A ●	●	N/A ●	N/A ●	●	N/A ●
RETAIL STORES: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ● ●	● ● ●	● ●	●	● ●	●	●	●	●	●
SCHOOLS: .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ●	● ●	●	● ●	● ●	● ●	● ●	●	● ●	●

- COMPETITIVE ON MARGINAL BASIS
 ● COMPETITIVE IF 15% ROLLED IN

EXHIBIT II-4
Sector: Residential/Commercial
Year: 1995

SECTOR: RESIDENTIAL/COMMERCIAL

YEAR: 1995

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
<u>RESIDENTIAL</u> SINGLE FAMILY DWELLINGS: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	● ● ●	●
<u>COMMERCIAL</u> MULTIFAMILY DWELLINGS: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
OFFICE BUILDINGS: .ELECTRIC HEAT PUMP .OIL HYDRONIC HEAT	N/A ●	N/A ●	N/A ●	●	N/A ●	●	N/A ●	N/A ●	●	N/A ●
RETAIL STORES: .ELECTRIC RESISTANCE .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ●	● ●	● ●	●	● ●	●	●	●	●	●
SCHOOLS: .ELECTRIC HEAT PUMP .OIL-FORCED AIR	● ●	● ●	●	● ●	● ●	● ●	●	●	● ●	●

- COMPETITIVE ON MARGINAL BASIS
● COMPETITIVE IF 15% ROLLED IN

The results are sensitive to the assumptions used about both the electric and the gas systems. Variations in the assumptions regarding:

- . Heat pump efficiency (coefficient of performance)
- . Gas system efficiency
- . Gas system capital costs

may significantly alter the results of the comparisons. While the assumptions used here reflect the best estimate of these factors, the sensitivity to reasonable changes indicates that caution should be used in assuming total sector shifts due to average break-even calculations.

(2) Office Buildings and Institutional Buildings (e.g., Schools) Are Attractive Commercial Sector High-Btu Gas Applications

High-Btu gas competes favorably in office buildings heated with oil hydronic systems in all regions of the country. The electric heat pump is used in only three of the warmer regions, and it is the preferred system in these regions. However, in the seven regions where the electric heat pump is not typically used, high-Btu gas is the preferred alternative, illustrated in the previously discussed Exhibit II-3 and Exhibit II-4. In institutional buildings, such as schools, HBG is competitive with both the electric heat pump and oil forced air in seven regions in 1990 (six in 1995). The electric heat pump is the most economically attractive system for heating multifamily dwellings in all regions, but HBG is more attractive than electric resistance and oil forced air heat in Regions 2 and 3 in the 1990-1995 period. Similarly, HBG competes to a limited extent in retail stores in four regions. It should be noted that HBG is preferred over oil in all cases, and in all regions, for residential and commercial application in both 1990 and 1995.

(3) Furnaces, Ovens, Non-Coal Boilers, and Some Kilns Are Attractive Industrial Applications

Exhibits II-5 and II-6 are graphic illustrations of the economic competitiveness of high-Btu gas in six representative industrial applications in 1990 and 1995.

EXHIBIT II-5
Sector: Industrial
Year: 1990

SECTOR: INDUSTRIAL

YEAR: 1990

APPLICATION	DOE REGION									
	1 New Eng.	2 NY/NJ	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
INDUSTRIAL BOILERS: .COAL .OIL						●		●		
BRICK KILNS: .COAL .OIL	●	● ●	●	● ●	● ●	●	●	●	●	●
CEMENT KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
GLASS FURNACES: .ELECTRICITY .OIL	● ●	● ●	● ●	● ●	● ●	● ●	● ●	● ●	● ●	●
STEEL REHEAT FURNACES: .OIL	●	●	●	●	●	●	●	●	●	●
FOOD OVENS: .ELECTRICITY	●	●	●	●	●	●	●	●	●	

● COMPETITIVE ON MARGINAL BASIS

● COMPETITIVE IF 15% ROLLED IN

EXHIBIT II-6
Sector: Industrial
Year: 1995

SECTOR: INDUSTRIAL

YEAR: 1995

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
INDUSTRIAL BOILERS: .COAL .OIL		●	●	●	●	●	●	●		
BRICK KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
CEMENT KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
GLASS FURNACES: .ELECTRICITY .OIL	●	●	●	●	●	●	●	●	●	●
STEEL REHEAT FURNACES: .OIL	●	●	●	●	●	●	●	●	●	●
FOOD OVENS: .ELECTRICITY	●	●	●	●	●	●	●	●	●	

● COMPETITIVE ON MARGINAL BASIS

● COMPETITIVE IF 15% ROLLED IN

In 1990, high-Btu gas under rolled-in pricing assumptions is the fuel of choice for glass furnaces, steel reheat furnaces, and food processing ovens in nearly all regions. HBG is also competitive with both coal and oil in brick kilns in Regions 2, 4, and 5. The brick kilns that are not equipped to burn coal favor HBG over oil in all regions. The current trend toward coal-fired cement kilns is expected to continue, as coal is the preferred fuel from an economic standpoint. However, the cement kilns without coal-burning capability are target markets for HBG. The 1990 boiler market is limited to oil-fired boilers in Regions 6 and 8. As oil prices escalate more rapidly than coal, HBG becomes competitive in Regions 2, 3, 4, 5, and 7 as well, as shown in the 1995 profile in Exhibit II-6. If oil prices rise faster than projected herein, high-Btu gas will also be more attractive in other regions in 1990. The overall industrial market for rolled-in HBG is broad in 1990, and becomes more extensive (in 1995) as oil prices continue to escalate rapidly.

3. WHEN HIGH-BTU GAS IS MARGINALLY PRICED, ITS ECONOMIC COMPETITIVENESS IS REDUCED

The economic competitiveness of high-Btu gas is significantly reduced when priced on a marginal (full cost) basis. However, even when priced on this basis, high-Btu gas is attractive in a number of areas. This is especially true in comparisons of gas versus oil, but less applicable when comparisons are made with the efficient heat pump.

(1) The Residential Sector Would Prefer Marginally Priced High-Btu Gas Over Oil as a Source of Heat Energy

When high-Btu gas is marginally priced, the heat pump is the economically favored system in all but Regions 1 and 2. However, as shown by the full dots on the Residential and Commercial Attractiveness Summary, Exhibits II-3 and II-4, HBG is favored over oil in all regions and over a majority of electric resistance applications (all regions but 9 and 10). The more favorable economics of the heat pump tend to limit the market for incrementally priced HBG to two Regions, as opposed to nine under rolled-in pricing. It should be noted, however, that this comparison is somewhat biased in favor of electricity over high-Btu gas, since marginally priced gas is being compared with average electricity prices.

(2) Office Buildings Are Still Attractive Commercial Applications

Office building heat can be provided most economically by incrementally priced high-Btu gas in seven regions in 1995 (four in 1990), as shown by the full dots in Exhibits II-3 and II-4. In Regions 4, 6, and 9, the electric heat pump is favored, but high-Btu gas still competes with oil hydronic heat. Multi-family dwellings, schools, and retail stores have preferred electric alternatives to incrementally priced HBG, but HBG in 1995 is always preferred to oil in these applications.

(3) Glass Furnaces, Ovens, and Some Kilns Are Attractive, but in Fewer Regions

The 1990 industrial attractiveness summary (Exhibit II-5) shows only food ovens as economically attractive applications for marginally priced HBG. However, the 1995 profile, Exhibit II-6, indicates several attractive applications. Food ovens and glass furnaces have no economic alternatives to high-Btu gas in most regions. Electricity is the preferred energy source for these applications in Regions 8 and 10, and oil is still competitive with marginally priced HBG in glass furnaces in Regions 9 and 10. Brick and cement kilns that do not have coal firing capability will find HBG preferable to oil in nearly all regions by 1995, although no applications appear in 1990. The steel reheat furnace and boiler markets disappear under incremental pricing of HBG, with no full dots showing on either Exhibit II-5 or II-6. Overall, while the market has diminished in terms of both applications and regions due to the higher cost of incrementally priced gas, there are still several attractive markets in the industrial sector for HBG under the higher pricing methodology.

4. ON A STAND-ALONE BASIS, A HIGH-BTU GAS PRODUCTION AND DELIVERY SYSTEM WOULD NOT BE ATTRACTIVE

Booz, Allen considered the feasibility of regional siting of high-Btu gas facilities with captive gas transmission and distribution facilities. The results show that for the system investigated, a Pennsylvania-sited facility with a New England distribution network, the concept is unattractive. A primary benefit of high-Btu gas is that it can take maximum advantage of existing fixed assets; however, this is not the case for a stand-alone system.

(1) On the Basis of the Breakeven Analysis, Only Food Processing Ovens Would Be Economically Attractive in 1995

With an estimated New England delivered price of over \$7.80 per million Btu (Exhibit II-7), high-Btu gas from a stand-alone system in Pennsylvania is only economically competitive in food ovens. With a stand-alone system, the gas could not be rolled-in with other gas sources. All of the other applications considered in this analysis have the option of utilizing a less expensive fuel. The Pennsylvania region was chosen because with its readily available coal and a mine mouth plant, siting, handling costs, and the ultimate HBG costs are reduced. The New England region was chosen as the delivery site because of its limited existing natural gas infrastructure. The construction of a new pipeline system, if HBG was attractive, would allow the demand to be filled. However, with only one application holding the economic potential for HBG use, the potential demand is extremely limited.

(2) Problems With Ensuring a High Load Factor Could Force the Price Even Higher

As discussed in Chapter IV, high-Btu gas costs are sensitive to plant operating factors. A 5 to 10 percent change in load factor could effectively erase the \$0.14 per million Btu economic benefit of using HBG in food processing ovens. The assumed 90 percent operating condition and gas costs are based on continuous production of HBG with no storage for fluctuating demand. This requires the potential users of a dedicated facility to have steady demand profiles. Otherwise, gas storage facilities at an added cost must be built, both to hold gas during low demand periods and to supply peak needs. This additional expense could also eliminate the economic differential.

Load problems are assumed to be minimal when HBG is piped through existing T&D systems with proportionately greater volumes of natural gas. The industry interviews conducted as part of this study indicated that HBG could comprise up to 25 percent of the gas supply, at steady load factors, with no problems. This would allow for continuous operation of the HBG facility to achieve high load factors, and subsequent lower costs per million Btu than a fluctuating, partially-loaded system and/or dedicated storage of the gas.

* * * * *

EXHIBIT II-7
Projected Stand-Alone High-Btu Gas Costs in 1995

Coal: Pennsylvania Bituminous @ \$27.45/ton, 25 million Btu/ton. This translates into a coal cost of \$1.78/million Btu of gas produced.
($\$27.45 \div 25 \div .617 \text{ efficiency} = \$1.78/\text{MMBtu}$)

Gasifier: Assume second generation technology available to gasify eastern caking coals at the same capital cost, output @ 125 MMCF/day, fixed charge \$4.05/MMBtu (includes capital and non-fuel O&M).

Transmission and Distribution: 500 miles of new pipeline @ \$280,000 per mile - \$140 million. Capital charge rate @ 16 percent. Throughput @ 45 trillion Btu/year or transmission charge @ \$0.49/MMBtu. Distribution charge @ \$1.50/MMBtu.

<u>Total Cost:</u>	Coal Cost:	\$1.78
	Gasifier Fixed Charge:	4.05
	T&D:	1.99
		<u>\$7.82/MMBtu</u>

This chapter has discussed the economic competitiveness of high-Btu gas with other fuels in the residential, commercial, and industrial sectors. HBG is competitive, on a rolled-in basis, in several residential, commercial, and industrial applications in many regions of the country, but is of a lesser attractiveness if incrementally priced. High-Btu gas competes favorably with oil in most applications whether priced on an incremental or rolled-in basis, and this attractiveness will increase as oil prices increase. The following chapter identifies the most likely regional markets for HBG.

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III. REGIONAL MARKETS OF PROMISE

The intent of this chapter is to indicate which regions and market sectors offer the greatest potential for high-Btu gas penetration. The effort is not meant to predict future gas consumption, but rather to determine which alternate energy sources (especially oil) could be replaced by rolled-in high-Btu gas, if available, on the basis of an economic determination. The economic determination of competitiveness was obtained from the break-even analysis of Chapter II, while the present chapter seeks to estimate the maximum size of potential high-Btu gas markets. The chapter is presented in three sections:

- . Methodology and assumptions used to aggregate regional markets
- . Identification of promising markets
- . Pipeline capacity and coal supply implications.

1. THE METHODOLOGY AND ASSUMPTIONS OF THIS ANALYSIS WERE CHOSEN TO ESTIMATE THE MAXIMUM POTENTIAL HIGH-BTU GAS MARKETS

In order to determine whether or not specific markets would be capable of supporting high-Btu gas projects, an estimate was made of each region's maximum addressable market in 1990 and 1995. These "addressable markets" indicate the maximum quantities of oil and electricity which could be replaced by high-Btu gas on the basis of economics and fuel switching capabilities. The following sections discuss the methodology and assumptions utilized for each of the sectors, and an illustrative example for the Midwest region is presented.

(1) High-Btu Gas Could Replace Significant Amounts of Oil and Electricity in the Residential and Commercial Sectors by 1995

The table on the following page sets out the projected energy demand by residential and commercial customers in the Midwest in 1995 for the Base Case and a "Shifted Demand" Case.

Projected Energy Demand in the Midwest in 1995
Trillion Btu (TBtu) per Year

	Base Case			Shifted Demand		
	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>
Residential						
Space Heat	1309	307	122	1365	307	66
Non-Space Heat	561	23	518	622	23	457
Commercial						
Space Heat	392	95	39	394	95	37
Non-Space Heat	98	5	521	99	5	520

The table indicates that residential gas demand in 1995 could be increased by some 117 TBtu, 61 TBtu attributable to non-space heating shifts. The increase in gas demand from the Base Case to the Shifted Case is offset by an equivalent decline in electricity consumption, whereas oil consumption remains unchanged. Shifts in the commercial sector are similar to the residential shifts, but they are of a lesser magnitude—gas usage increases by 3 TBtu while electricity falls by this same amount.

These demand shifts represent the total potential demand, or markets, for high-Btu gas. A summary of the potential demand shifts is set out by regions for 1990 and 1995 in the Appendix, Exhibit E-1, and also in Exhibit III-1 presented in this chapter. The formulation of these potential markets is described below.

The Base Case total residential and commercial demand data were obtained from the Base Case described in Chapter I and set out in detail in Appendix A. The sector totals were divided into space heating and non-space heating components in order to determine what portion of the total oil and electricity consumption was attributable to applications directly competitive with gas. That is, all electricity used by residential customers could not be replaced by natural gas, since the majority of this sector's energy usage is for applications which do not allow fuel switching, e.g., for

lighting and household appliances. The split between heating and non-heating loads was made assuming that:

- . Seventy percent of residential gas and 80 percent of commercial gas is consumed for space heating
- . Ninety-three percent of residential oil and 95 percent of commercial oil is consumed for space heating
- . Only 19 percent and 7 percent respectively of all residential and commercial electricity is used for space heating.

With regard to the potential for replacing non-space heating oil and electricity with natural gas, the following determinations were made:

- . All non-space heating residential and commercial oil consumption is in applications directly competitive with gas; i.e., water heating.
- . Only 26 percent of residential electricity consumed for non-space heating purposes competes directly with gas (water heating and cooking), and less than 1 percent of the commercial sector's non-space heating load is competitive (water heating).

These assumptions are based on data compiled by Oak Ridge National Laboratory in 1977 and 1978 in: Commercial Energy Use, A Disaggregation by Fuel, Building Type, and End Use and Residential Energy Use to the Year 2000.

Thus, virtually all 430 TBtu supplied by oil to the residential and commercial sectors of the Midwest could be replaced by gas. Of the 1,200 TBtu projected to be supplied by electricity in the Base Case, however, only 300 TBtu could shift to gas.

Once the estimate of the market share which could shift to gas was made, the break-even analysis was used to determine what market segments would shift on economic grounds. The projected cost of gas in 1995 (including the rolled-in cost of high-Btu gas accounting for 15 percent of the total gas supply) is less than the

break-even cost of the oil forced air system and the electric heat pump in the Midwest. Therefore, a total shift away from oil and electricity for residential heating might be expected for the maximum potential gas market, reducing competing fuel consumption to zero. However, the table indicates only a 56 TBtu decline in electricity demand and no decline in oil demand. The reasons are two-fold:

- . Switching from oil or electricity to gas is possible only when consumers purchase new gas-burning equipment, either for new homes or commercial establishments, or for the replacement of worn-out equipment. A 15-20-year life is assumed for all commercial equipment, and therefore, the annual turnover in stock is roughly 5-7 percent. A 15-year life is assumed for residential electric resistance and gas furnaces, and the assumptions for oil furnaces and electric heat pumps are 13 and 10 years respectively.
 - . Results from the macro-analysis show negative oil demand growth is projected in all sectors in all regions. This implies that aging oil-fired equipment will be replaced by electric or gas systems, and that new installations will not use oil. No acceleration of the Base Case scenarios was assumed in the shifted demand case.
- (2) The Potential Industrial Markets for High-Btu Gas Are Substantially Larger Than the Residential and Commercial Markets

The table below illustrates the Base Case and Shifted Demand Case for the industrial sector in the Midwest.

Projected Energy Demand in the Midwest in 1995
(TBtu/year)

	Base Case			Shifted Demand		
	Gas	Oil	Elec- tricity	Gas	Oil	Elec- tricity
Industrial						
Boiler	175	83	--	258	--	--
Non-Boiler	525	627	1550	1152	--	1550

The Base Case industrial demand was obtained from the Appendix, Exhibit A-3. This demand was divided into boiler and non-boiler components by combining information on the particular region's industrial composition with knowledge regarding industrial fuel use. For example, approximately 50 percent of industrial gas consumption in the Southwest is accounted for by the chemical industry, an industry in which boiler fuel usage accounts for about one-third of total gas consumption. Conversely, about 26 percent of the gas consumed in the Northwest is used in the pulp and paper industry, an industry in which nearly 90 percent of the gas consumed is as a boiler fuel. Thus, the estimated portion of gas which is used as a boiler fuel in the Northwest is higher than that for the Southwest. It was estimated that 33 percent of all industrial gas consumed in the 10 regions is boiler fuel, as compared with 55 percent of industrial oil. In the Midwest, the current portion of gas consumed as a boiler fuel was set at 38 percent. Due to the Powerplant and Industrial Fuel Use Act, boiler fuel oil and gas consumption was projected to fall steadily in every region.

Some of the industrial fuel switching from oil to natural gas is attributable to boiler units. Such switching would be lawful, given the mandate of the Fuel Use Act, only for units built pre-1978. Should the average boiler life vary from the 25 years assumed herein, or should the Fuel Use Act be reinterpreted, the oil-to-gas switching would vary similarly.

The Base Case oil demand does not include oil used as a feedstock or raw material. Thus, the remaining (non-feedstock) oil demand, both boiler and non-boiler, could be switched to gas with little difficulty.

The projected price of industrial gas, including 15 percent rolled-in high-Btu gas, is less than the break-even price of oil for both boiler and non-boiler applications in the Midwest in 1995. Thus, all oil consumption is diverted to gas from the base case to the shifted demand case. This total shift is a result of the assumption of complete interchangeability between oil and gas for non-process and non-feedstock uses, and the assumption that boiler units, allowed to operate with oil post-1990, would also be allowed to operate on gas.

Other points to be made regarding the industrial projection are that:

- . Industrial demand patterns are more conducive to a constant output high-Btu gas project than are the weather-sensitive residential and commercial patterns.
- . No switching from electricity to gas is considered due to the limited number of industrial applications in which gas and electricity are interchangeable.
- . The projected price of gas is below the breakeven oil price for non-boiler applications in all regions in both 1990 and 1995.

2. THE LARGEST POTENTIAL MARKETS FOR HIGH-BTU GAS ARE LOCATED IN THE MID-ATLANTIC AND MIDWEST

The shifted demand required to support a 125 MMcfd high-Btu gas project operating at 90 percent capacity is roughly 41 TBtu per year. As indicated in Exhibit III-1, this level is surpassed in seven of the ten regions in 1990 and 9 of the 10 regions in 1995. It must be stressed that these estimates are of the maximum potential demand shifts. The regional summary indicates that:

- . The addressable markets of 449 TBtu in the Mid-Atlantic in 1995 and 830 TBtu in the Midwest are substantially greater than those in other regions. Both of these regions have a heavy industrial concentration, fueled in large part by oil. These regions also exhibit large potential residential shifts from electricity.
- . The addressable markets in the South Atlantic, Southwest, and the West are in the 300 to 400 TBtu range in 1995. These three markets are similar in that they all exhibit significant potential shifts in industrial oil consumption, and also in residential electricity consumption. The magnitude of the potential electricity shifts is heavily dependent on assumptions regarding heat pump efficiencies.
- . The New England and New York/New Jersey addressable markets are both approximately 200 TBtu in 1995. Approximately 80 percent of these market totals are attributable to industrial fuel oil.

EXHIBIT III-1(1)
Potential Shifts in Energy Demand
(TBtu)

Region Sector	1990			1995		
	Gas	Oil	Elec- tricity	Gas	Oil	Elec- tricity
New England						
Residential	6	--	(6)	35	--	(35)
Commercial	1	--	(1)	5	--	(5)
Industrial	84	(84)	--	178	(178)	--
Total	91	(84)	(7)	218	(178)	(40)
New York/New Jersey						
Residential	6	--	(6)	38	--	(38)
Commercial	1	--	(1)	4	--	(4)
Industrial	54	(54)	--	160	(160)	--
Total	61	(54)	(7)	202	(160)	(42)
Mid-Atlantic						
Residential	11	--	(11)	66	--	(66)
Commercial	--	--	--	3	--	(3)
Industrial	150	(150)	--	380	(380)	--
Total	161	(150)	(11)	449	(380)	(69)
South Atlantic						
Residential	30	--	(30)	183	--	(183)
Commercial	--	--	--	2	(220)	(2)
Industrial	62	(62)	--	220	--	--
Total	92	(62)	(30)	405	(220)	(185)
Midwest						
Residential	20	--	(20)	117	--	(117)
Commercial	--	--	--	3	--	(3)
Industrial	280	(280)	--	710	(710)	--
Total	300	(280)	(20)	830	(710)	(120)
Southwest						
Residential	15	--	(15)	88	--	(88)
Commercial	--	--	--	2	--	(2)
Industrial	180	(180)	--	220	(220)	--
Total	195	(180)	(15)	310	(220)	(90)

EXHIBIT III-1(2)
Potential Shifts in Energy Demand
(TBtu)

<u>Region Sector</u>	<u>1990</u>			<u>1995</u>		
	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>
Central						
Residential	7	--	(7)	41	--	(41)
Commercial	--	--	--	2	--	(2)
Industrial	4	(4)	--	30	(30)	--
Total	11	(4)	(7)	73	(30)	(43)
North Central						
Residential	4	--	(4)	23	--	(23)
Commercial	--	--	--	--	--	--
Industrial	10	(10)	--	20	(20)	--
Total	14	(10)	(4)	43	(20)	(23)
West						
Residential	15	--	(15)	90	--	(90)
Commercial	--	--	--	1	--	(1)
Industrial	116	(116)	--	177	(177)	--
Total	131	(116)	(15)	268	(177)	(91)
Northwest						
Residential	--	--	--	--	--	--
Commercial	--	--	--	--	--	--
Industrial	18	(18)	--	40	(40)	--
Total	18	(18)	--	40	(40)	--
Note: Brackets denote negatives						

- . The addressable market in the Central region is 73 TBtu in 1995, but only 11 TBtu in 1990.
- . Neither the North Central nor Northwest regions appear to exhibit sufficient addressable markets to justify a high-Btu gas project by 1995 on their own. These are the two regions with the lowest total energy consumption, and oil consumption is negligible. Furthermore, electricity prices are extremely low in the Northwest. However, significant electricity price changes could enhance the viability of a high-Btu gas project, and such shifts are possible due to a declining dependence on hydroelectricity.

The estimate of the addressable market potentially subject to high-Btu gas penetration takes into account the flux of the other supplemental gas supplies. That is, the Alaskan gas, Canadian gas, Mexican gas, and imported LNG expected to come on-stream by 1990 and 1995 were not treated as competitors to high-Btu gas. Rather, the addressable market for high-Btu gas is derived from demand over and above that which might be satisfied by conventional and other supplemental sources of supply.

The projected gas supplies to each region are set out in Exhibit III-2. The total regional gas supply, when subtracted from the shifted demand, leaves the residual maximum addressable market. For example, in the Midwest, in 1995, conventional and other supplemental gas supplies are estimated to contribute 1820 and 1240 TBtu respectively to the shifted demand of 3890 TBtu. The residual maximum addressable market is, therefore, 830 TBtu.

3. COAL SUPPLY AND PIPELINE CAPACITY CONSTRAINTS DO NOT POSE SIGNIFICANT BARRIERS TO HIGH-BTU GAS PLANT OPERATIONS

The operation of a 125 MMcfd high-Btu gas plant would require annual coal feedstocks of approximately 5 million tons of lignite, as well as adequate pipeline capacity to transport some 41 TBtu per year. The following sections discuss the potential for such problems in supplying coal to, or transporting gas from, such facilities.

EXHIBIT III-2
Projected Sources of Gas Supply in
1990 and 1995
(TBtu).

<u>Year/Source</u>	<u>New England</u>	<u>New York New Jersey</u>	<u>Mid Atlantic</u>	<u>South Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>1990</u>											
Domestic Conventional ²	411	660	1060	1668	2134	4720	928	605	811	112	13,109
Alaska	14	46	61	100	282	55	16	9	245	18	876
Canada	40	5	--	--	367	--	--	52	449	187	1,100
LNG	23	74	127	110	242	4	14	--	309	--	903
Mexico	5	15	26	22	49	1	2	--	63	--	183
Synthetic Gas ¹	17	70	36	--	136	--	--	34	3	83	379
Total	510	870	1310	1900	3210	4780	990	700	1880	400	16,550
Shifted Demand	601	931	1471	1992	3510	4975	1001	714	2011	418	
Maximum Address- able Market	91	61	161	92	300	195	11	14	131	18	
<u>1995</u>											
Domestic Conventional ²	321	618	1030	1628	1820	5049	900	520	802	126	12,884
Alaska	14	46	61	100	282	55	46	9	245	18	876
Canada	40	5	--	--	367	--	--	52	449	187	1,100
LNG	23	74	127	110	242	4	14	--	309	--	903
Mexico	5	15	26	22	49	1	2	--	63	00	183
Synthetic Gas ¹	57	82	36	--	300	111	18	79	82	79	844
Total	460	840	1280	1863	3060	5220	980	730	1950	410	16,790
Shifted Demand	678	1042	1729	2265	3890	5530	1053	773	2213	450	
Maximum Address- able Market	218	202	449	405	830	310	73	43	268	40	

¹ Includes SNG from naptha and medium-Btu gas; does not include high-Btu gas.

² Note that gas used as raw material, feedstock, refinery or electric utility fuel is excluded. Thus, total U.S. demand is reduced by some 3,000 TBtu, all of which it is assumed would have been supplied through domestic conventional sources.

(1) The Existing Natural Gas Pipeline Network has the Ability to Deliver Over 24 Trillion Cubic Feet of Gas Per Year

It is unlikely that the construction of plants to deliver high-Btu gas would place a strain on the extensive existing pipeline network. Eight plants, each producing 41 TBtu per year, would be able to account for a combined total of less than 1 percent of existing pipeline capacity. Declines in industrial gas consumption, coupled with the virtual elimination of the utility market by 1990 as mandated by law, as well as slow-growth in residential/commercial demand, will further free pipeline capacity. The table below indicates 1970 gas deliveries by region for each of the regions under consideration, and the projected 1995 demand absent any high-Btu gas demand. The difference is the "implied excess capacity."

Pipeline Deliveries and Implied Excess Capacity by Region

Region	1970 Deliveries (TBtu)	Projected 1995 Deliveries (TBtu)	Implied Excess Capacity (TBtu)
New England	265	465	(200)
New York/New Jersey	1076	840	236
Mid-Atlantic	1382	1280	102
South Atlantic	2238	1860	378
Midwest	4574	3060	1514
Southwest	7701	5220	2481
Central	1654	970	684
West	2521	1950	571

Sufficient capacity to transport 41 TBtu per year is indicated for each of the regions with the exception of New England in 1995. However, sources reviewed regarding capacity in New England were inconsistent and inconclusive. It is clear, however, that 41 TBtu per year would tax the less extensive pipeline network in New England more than would be the case in any other region.

(2) The Coal Industry Is Currently Operating Some
150 Million Annual Tons Per Year Below Capacity

Current coal production in the U.S. is at a level of roughly 700 million tons per year. This output level is about 150 million tons below the current capacity of 850 million tons per year. Eight high-Btu gas plants of the size of the Great Plains project (125 MMcfd) would consume 40 million tons per year, some 5 percent of the current output level and 4 percent of capacity. The construction of these plants would not be hindered by coal supplies, as productive capacity is expected to continue to exceed demand in the mid-term. Further, coal reserves for a project of this magnitude would likely be dedicated prior to initial operation, as is the case with all of the plants currently under consideration.

Some problems could arise, however, if a number of plants were to come on line at the same time and in the same region. A heavy regional concentration of plants could pose a threat to environmental quality.

* * * * *

The purpose of this chapter was to discuss the methodology and assumptions used to project maximum future high-Btu gas markets and to identify the most promising regional and sectoral potential markets. Chapter IV deals with the sensitivity of the cost of high-Btu gas to assumptions regarding plant size, feedstock costs, and financing.

IV. SENSITIVITY ANALYSIS OF THE TAILGATE COST OF HIGH-BTU COAL GAS

The ability of high-Btu gas from coal to supplement natural gas supplies and to supplant competing forms of energy will be in part dependent upon the cost at which it can be produced, given the volumetric requirements of the market. Thus, an important test of high-Btu gas marketability will be the relationship between the size of the plant and the cost of the output. In addition, the sensitivity of tailgate costs to changes in capacity factor, coal feedstock costs and financing will also be relevant in assessing the market penetration of SNG.

Estimates of the tailgate cost of coal gas are subject to a wide range of variation, depending on the assumptions concerning financing, plant operation, and technology. For the purposes of this analysis, it was assumed that Lurgi technology would initially produce the bulk of high-Btu gas supplies. A range of cost estimates were then developed for key sensitivity factors which were relevant to the market analysis.

Based on an analysis of publicly available data and information, estimates of the tailgate cost of SNG were developed for a commercially feasible range of plant sizes. The estimates which were tested during our field research are considered reasonable. These resultant costs are as follows:

<u>Estimated Tailgate Cost of SNG*</u> <u>(1978 dollars)</u>	
<u>Plant Size</u>	<u>Cost (\$/Mcf)</u>
60 MMcf/day	\$5.64
125 MMcf/day	4.95
250 MMcf/day	4.41
* Lurgi Plant at 90 percent capacity factor, 950 Btu/cu. ft., levelized cost.	

Sensitivity analyses were also undertaken with respect to three areas:

- . Changes in capacity factor
- . Changes in coal feedstock cost
- . Changes in costing methodology.

The results of these sensitivity analyses indicate that changes in pricing methodology could have the most significant impact on the market penetration of high-Btu coal gas; that tailgate cost is extremely sensitive to changes in capacity factor; and that changes in coal cost will have less of an impact on tailgate costs than the other two factors.

1. COST DATA AND TAILGATE COST ESTIMATES WERE BASED ON TWO SOURCES

Two primary sources of data were used to estimate the plant tailgate costs, a study by C.F. Braun & Company for ERDA, and the filing of Great Plains Gasification Associates before the FERC.*/** The C. F. Braun study was selected because it provided a consistent and detailed set of cost technologies. However, the cost estimates were conceptual and based upon a standard plant size of 250 million cubic feet per day. Alternatively, the Great Plains filing provides actual cost data for the only commercially active high-Btu coal gasification project in the United States. It is also of value because the costs are based upon a smaller plant design of 125 million cubic feet per day using Lurgi technology.

The Braun study was used as the basis for deriving costs for smaller-sized plants, while the Great Plains filing provided a check upon the derived costs for the smaller-sized 125 MMcf/day plant. The procedure used to estimate the tailgate costs consisted of the following steps:

- . Update Braun capital and O&M costs to a 1978 base
- . Derive costs for alternate plant sizes of 125 and 60 MMcf/day using a standard scaling equation, and compare results with Great Plains filing

* Factored Estimates for Western Coal Commercial Concepts, C. F. Braun Co., October, 1976.

** Great Plain Gasification Associates (successor to ANR Gasification Company and PGC Coal Gasification Company), Docket No. CP78-391.

- Review and revise financial assumptions
- Compute tailgate cost/price for alternate plant sizes based upon levelized, non-levelized and DCF methodologies as developed by AGA and as utilized in the Braun study.

Based upon our discussions with industry, the range of plant sizes selected for the study were found to be realistic in terms of engineering and economic design. Accordingly, it would be unlikely that plants larger than 250 MMcf/day or smaller than 60 MMcf/day would be built.

The estimates of plant investment and operating costs to reflect alternate plant sizes were based on two adjustments. First, plant investment costs were adjusted from the 250 MMcf/day design by using a standard chemical engineering scale equation in order to reflect inherent economies of scale.* Operating costs were adjusted proportionately according to plant size.

The result of these cost adjustments for the 125 MMcf/day plant is set out in Exhibit IV-1 and compared with Great Plains.

EXHIBIT IV-1
Cost Comparison
Lurgi Plant (125 MMcf/day)

<u>COST COMPONENT</u>	<u>GREAT PLAINS^a</u> <u>('78 \$ Million)</u>	<u>C.F. BRAUN (ADJUSTED)</u> <u>('78 \$ Million)</u>
Plant Investment	\$890.5	\$945.0
Gross O&M	106.4	108.6
Net O&M ^b	87.0	74.0
Working Capital	14.0	19.0
Coal Costs	7.52/ton	7.50/ton

^a Exhibit 19D, CP78-391

^b Less by-products credits

* The equation used is $C_x = n^{0.7} C_k$, where C_k is known plant investment, n is the ratio of plant capacities and C_x is unknown plant investment.

The small differences between the key parameters of plant investment and gross O&M, provided support for the cost adjustment for plant size. The major difference between the two estimates arises with respect to the net operating costs and working capital, both of which are imputed calculations. The adjustments for by-product credits (revenues) was believed to be the most subject to factors outside the immediate plant environment. By-product revenues were, therefore, reduced by approximately 50 percent, thereby producing a more conservative estimate.

The cost data having been assembled, assumptions were then made concerning financial parameters. It was assumed for the purposes of this analysis that a utility or group of utility-type companies would be representative of the owner of a high-Btu coal gas plant. The following assumptions were then used as a basis for estimating tailgate costs:

<u>Key Assumptions</u>		
.	Plant life	20 years
.	Plant Capacity	
.	Factor	90%
.	Depreciation	Straight line
.	Debt-Equity	
.	Ratio	75/25
.	Interest on	
.	debt	10.75%
.	Return on Equity	15%
.	FIT rate	48%

The methodology used to calculate the tailgate unit cost of gas reflects the utility ownership assumption. Accordingly, a levelized pricing methodology was adopted, similar to that utilized in the Braun study.* The levelized method essentially averages the revenue required by a plant over its 20-year life.** This method results in an understatement of costs in initial project years and an overstatement in later years, primarily due to the holding of the depreciation expense constant rather than declining over time.

* The Braun methodology is based on an approach developed in 1961 and updated in 1971 for the FPC Natural Gas Survey's Synthetic Coal Gas Task Force.

** The revenue requirement equals the sum of return on rate base, Federal income taxes, depreciation, and net operating costs.

The impact on the cost of gas of a non-levelized approach was also examined as an alternative case, as was the utilization of a DCF internal rate of return approach assuming non-utility ownership. Three alternate ownership scenarios are discussed in Section 2(3).

The resultant tailgate unit costs of pipeline quality coal gas utilizing Lurgi technology are shown in Exhibit IV-2 on both a dollar per Mcf and cents per million Btu basis. Also shown, although not completely comparable, are the other sources of estimates as well as more recent studies, undertaken by the Congressional Research Service, and the Engineering Societies Commission on Energy (ESCOE).

From the exhibit it can be seen that consistent estimates across plant sizes have not been generally available. Thus, a significant output of this study has been to generate such data in order to undertake the market analysis. The estimated costs of high-Btu gas derived from alternate-sized plants indicate a decline of 22 percent as plant size is increased from 60 to 250 MMcf/day due to the inherent economies of scale.

2. SENSITIVITY ANALYSES INDICATED A WIDE RANGE IN GAS COST

The tailgate cost of high-Btu coal gas will be subject to a host of changing conditions. Sensitivity analyses were conducted with respect to three areas, which are deemed relevant to the market appraisal. These included the following:

- . Sensitivity to capacity factor
- . Sensitivity to coal feedstock cost
- . Sensitivity to costing methodology

(1) Sensitivity to Capacity Factor

The capital intensity of gasification plants dictates that they be operated as close to full capacity as possible in order to minimize unit costs. Most studies and analyses, including this one, assume a 90 percent capacity factor. However, it is of interest to examine the cost variation, to the extent that problems arise preventing full utilization of capacity. Exhibit IV-3 sets out the results of this sensitivity analysis, for each relevant plant size.

EXHIBIT IV-2
Estimated Tailgate Cost of High-Btu
Coal Gas for Alternate Size Plants

Plant Size	Adjusted ^a C.F. Braun Data		Original ^b C.F. Braun		Great Plains ^c		Congressional ^d Research Service		ESCOE ^e	
	\$/Mcf	\$/MMBtu	\$/Mcf	\$/MMBtu	\$/Mcf	\$/MMBtu	\$/Mcf	\$/MMBtu	\$/Mcf	\$/MMBtu
250 MMcf/day	4.41	4.34	3.13	3.30	N/A	N/A	3.35	3.53	3.70	3.89
125 MMcf/day	4.95	5.21	N/A	N/A	5.66	5.96	N/A	N/A	N/A	N/A
60 MMcf/day	5.64	5.33	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

a 950 Btu/c.f.

b Factored Estimates for Western Coal Commercial Concepts, C.F. Braun, Co., October 1976.

c CP78-391

d Synthetic Fuels From Coal: Status and Outlook of Coal Gasification and Liquefaction, Committee on Energy & Natural Resources, GPO, June 1970, pg. 129.

e Coal Conversion Comparisions, Rogers K.A. and Hill R.F., ESCOE, Prepared for EOE, July 1979.

EXHIBIT IV-3
Sensitivity of the Tailgate Cost of High-Btu Coal Gas
to Plant Capacity Factor
(1978 Dollars)

Lurgi Technology

¹ACTUAL OUTPUT/DESIGN CAPACITY

The exhibit shows that tailgate costs are extremely sensitive to changes in capacity factor. The following table compares the tailgate costs at 90 percent capacity factor to those at 50 percent.

<u>Comparison of Tailgate Costs</u> <u>at Alternate Capacity Factors</u> <u>(1978 \$)</u>			
<u>Plant Size</u>	<u>\$/Mcf</u>		<u>Percent Increase</u> <u>in Cost</u>
	<u>90%</u>	<u>50%</u>	
250 MMcf/day	\$4.41	\$6.37	44.4%
125 MMcf/day	4.95	7.42	49.9
60 MMcf/day	5.64	8.72	54.6

The changes in tailgate costs show substantial increases when the capacity factor drops to one-half of design capacity. Moreover, the impact is larger for smaller-sized plants since investment costs do not fall proportionately, while output is lower. The necessity to match plant size with market needs is clearly evident from this analysis.

(2) Sensitivity to Coal Feedstock Costs

A high-Btu coal gasification plant providing 250 MMcf/day using Lurgi technology will consume approximately 30,000 tons per day of lignite coal. Consequently, coal costs contribute significantly (i.e., approximately one-half) to operation and maintenance costs. Thus, given the regional variations in coal cost, it was deemed relevant to examine the sensitivity of tailgate costs to this factor. Exhibit IV-4 sets out the results of this analysis for alternate plant sizes.

The exhibit shows that while the tailgate costs of gas increase with attendant increases in coal feedstock costs, the impact is not as substantial as the sensitivity to capacity factor. This is illustrated in the table following Exhibit IV-4 for two feedstock cost levels.

EXHIBIT IV-4
Sensitivity of the Tailgate Cost of High-Btu Coal Gas
to Coal Feedstock Cost
(1978 Dollars)

Lurgi Technology

Impact of Coal Feedstock Cost
on Plant Tailgate Cost
(1978 Dollars/Mcf)

<u>Size</u>	<u>Coal Cost</u>		<u>Percent Increase</u>
	<u>@ \$7.50/ton</u>	<u>@ \$10.50/ton</u>	
250 MMcf/day	\$4.41	\$4.77	8.2%
125 MMcf/day	4.95	5.31	7.3
60 MMcf/day	5.64	6.00	6.4

The impact of a 40 percent increase in coal costs result in a 6 to 8 percent change in plant tailgate costs. Since coal consumption is in proportion to plant size, the impact declines with smaller plant size. It would appear therefore, that the location of a plant would be based partly on feedstock cost considerations.

(3) Sensitivity to Pricing Methodology

In discussing the calculations of the tailgate cost of gas above, it was stated that a levelized approach was used. While this approach is useful for comparative purposes, it may not be representative of how the gas could be priced in actuality. Moreover, it is useful to show how sensitive the results are to the alternate approaches. For this reason, two alternative pricing methodologies were calculated—one using a non-levelized approach and utility financing, the other assuming private financing and using a discounted cash flow (DCF)/internal rate of return approach. * **

* The major difference for private financing is the assumption of 100 percent equity.

** The Discounted Cash Flow/Internal rate of return methodology is a capital budgeting technique which is used to determine the rate of return which will equate the future cash flow of a project to the cost of that project. In the context of this study where the rate of return is assumed; costs and output are known, we sought to estimate the "price" which would generate the future cash flow stream.

EXHIBIT IV-5
 Sensitivity of the Tailgate Cost of High-Btu Coal Gas
 to Various Financial and Costing Approaches
 (1078 Dollars)
 Lurgi Plant (125 MMcf/Day)

This sensitivity analysis was calculated for one plant size of 125 MMcf/day. The results of the analysis are shown in Exhibit IV-5. The levelized cost is simply the tailgate cost previously set out. The non-levelized cost approach shows the cost in the first four years of the project to be above \$6 per Mcf, and not reaching parity with the levelized approach until the eleventh year. Alternatively, the DCF approach private financing case, represented by the dashed line, results in an average price of \$7.90 per Mcf, significantly above the utility levelized costing approach. The major reason for this difference is the reduction of risk in the utility financing case which results in a lower capital charge rate. The results of this analysis have a direct implication with respect to marketability of the gas, in that the higher cost levels associated with the alternative pricing approaches may act as a barrier to market entry.

+ * * *

This section has demonstrated that the tailgate cost of high-Btu coal gas will range from approximately \$4 to \$6 per Mcf depending on plant size. In addition, the costs will vary significantly depending on plant capacity factors, coal feedstock costs and pricing approach.

V. BARRIERS TO HIGH-BTU GAS MARKET PENETRATION

Previous chapters in this report have focused on economic aspects of the market attractiveness of high-Btu coal gas. Although the potential for penetration of the technology has been shown to exist in a number of applications, other factors that bear upon the development of a market for such gas have been identified during the study. This chapter of the report examines barriers to market penetration of high-Btu coal gas which stem from other sources, and which have resulted in project suspensions or cancellations.

A number of coal gasification projects were started (see Exhibit V-1 for a summary listing) as the gas industry became convinced that production declines of the 1970's could be partly offset by the introduction of gas supplies from supplemental sources. For various reasons, all commercial projects have been suspended or cancelled except for the Great Plains Gasification Project. During the preparation of this study, two events occurred which may influence the success of future projects:

- . The petroleum product shortage of the second and third quarters of 1979 renewed interest within the Congress and the Administration in rapid development of a synthetic fuels industry.
- . The Federal Energy Regulatory Commission, reversing an earlier administrative law judge's decision, approved the Great Plains Gasification project, regarded by the industry as a prototype project.

The barriers analysis which follows examines three categories of barriers—technological, financial, and institutional. The observations contained herein are based upon a series of interviews with key participants in the industry. Appendix D lists the organizations contacted in this part of the project.

EXHIBIT V-1(1)
Status of Commercial and Demonstration High-Btu Coal Gasification Projects
(As of September 1979)

Controlling Company	Site	Process	Coal Feed, Tons/day	Peak Output MMcf/day	Status
COMMERCIAL PROJECTS					
WESCO, Texas Eastern Transmission Corp. and Pacific Lighting Corp.	Four Corners Area. N.M.	Lurgi gasification with methanation	25,625	275 Expansion	Project cancelled
American Natural Resources Co., Peoples Gas Co., (North American Coal Corp.)	Beulah-Hazen Area. Mercer County N.D.	Lurgi gasification with methanation	13,636	137.5	Project obtained conditional approval of the FERC
El Paso Natural Gas Company	Four Corners Area. N.M.	Lurgi gasification with methanation	28,250	288	Filing of new application before the FERC is expected
Panhandle Eastern Pipe Line Company (Peabody Coal Co.)	Eastern Wyoming	Lurgi gasification with methanation	27,700	275	No filing has yet been made to the Federal Energy Regulatory Commission because of the perceived unfavorable regulatory climate.
Natural Gas Pipeline Co. of America	Dunn County, N.D.	Lurgi gasification with methanation	30,000	270	Plans held in abeyance due to capital constraints
Northern Natural Gas Company	Powder River Basin, Mont.	Lurgi gasification with methanation	30,000	275 Expansion	Project suspended.
The Columbia Gas System, Inc.	Illinois	--	--	--	Illinois coal is being held by Company for coal gasification pending develop- ment of an economic and technically sound process.
Panhandle Eastern Pipe Line Co., and City of Wichita, Kansas	Wichita, Kansas	Lurgi gasification with methanation	--	250	Project cancelled
Panhandle Eastern Pipe Line Co. (Peabody Coal Co.)	Southern Illinois	Lurgi gasification with methanation	--	--	Project cancelled
Cameron Engineers	Colorado	Lurgi gasification with methanation	34,250 plus 6000 tons of solid waste per day.	275	Project suspended
Mono Power Co., Resources Co., and New Albion Resources Co.	Kaiparowits Plateau, Utah	Lurgi gasification with methanation	32,900	360	Project cancelled

Source: American Gas Association Gas Supply Review supplemented by Bcoz, Allen interviews.

EXHIBIT V-1(2)

Controlling Company	Site	Process	Coal Feed, Tons/day	Peak Output MMcf/day	Status
Exxon Corporation. (Carter Oil)	Northern Wyoming	---	--	---	Feasibility studies have been completed. Project cancelled because of projected economics.
Consolidated Natural Gas Company	Southwest Pennsylvania	---	--	---	The company has purchased about 500 million tons of recoverable coal for gasification. Company is offering demonstration project to be jointly funded with DOE.
<u>DEMONSTRATION PROJECTS</u>					
Concco Coal Development Company & DOE	Noble County, OH	Slagging Lurgi with methanation	3,800	60	DOE has awarded the company a \$24 million contract to design the demonstration facility. The design phase will last about 22 months followed by a construction period of 2½ years. Plant operations are expected to last for 3½ years. Total project cost is estimated at \$324 million. The cost for construction and operations will be shared equally by DOE and the company.
Illinois Coal Gasification Group & DOE	Ferry County, IL	COGAS Process	2,200	18 Plus 2400 bbl/d synthetic crude oil.	DOE has awarded this group of companies a \$22.5 million contract to design the demonstration plants. The design will last about 21 months. Construction and operation phases are expected to last 34 and 42 months respectively, with costs shared equally between DOE and the group. Total costs are estimated to be \$334 million.
Procon, Inc. & DOE	--	HYGAS	--	--	DOE has awarded Procon, Inc. a 2 year, \$7.5 million contract for a conceptual design of a commercial plant and a process design and economic evaluation of a demonstration plant. The Institute of Gas Technology has a separate contract under the joint A.G.A.—DOE pilot plant program to supply data from the HYGAS pilot plant for the Procon, Inc. design.
Coalcon Dept. Union Carbide Corp. & DOE	New Athens, IL	Union Carbide	2,600	22 (Plus 2900 bbl of syncrude per day)	The process design stage was completed in June 1977, DOE has not announced any further plans.

Source: American Gas Association Gas Supply Review supplemented by Booz, Allen interviews.

1. TECHNOLOGICAL BARRIERS STEM FROM THE FACT THAT A FULL SIZE, INTEGRATED HIGH-BTU COAL GASIFICATION PLANT HAS NEVER OPERATED COMMERCIALY

There is some risk that problems of scale-up or systems integration will hinder reliable operation of the first few commercial-sized plants in the U.S. An example of this risk is the longer than normal shakedown period postulated by one project sponsor to correct design deficiencies in order to achieve the design operating factor. This risk is important because coal gasification plants are capital intensive and tailgate costs are highly sensitive to capacity utilization. Project participants have pointed out, however, that each of the individual process steps, except for the methanation of coal-derived synthesized gas, have been demonstrated in commercial-sized facilities. It is noted that each of the commercial projects that have been announced would employ Lurgi gasification with methanation. Companies interviewed appear to be satisfied with the currently available technology and confident in their ability to make it workable.

In order to minimize the risk of technological problems, project sponsors are pursuing several options. For first generation plants, potential sponsors are:

- . Selecting only current commercially available gasifiers
- . Designing for redundancy to maintain a high probability that design reliability specifications will be met
- . Extensively instrumenting these plants for integrating process flows and monitoring effluents.

Many companies interviewed feel that it would be a mistake to await the development of second generation technology, the major advantage of which is the ability to gasify highly-caking Eastern coals. These companies note that potential cost reductions would be on the order of 10 to 15 percent, or about equivalent to 1 year of inflation. They also note, however, that second generation technologies will benefit from the operational experience of first generation technology (i.e., debottlenecking, designing for ease of maintenance, system integration, etc.).

It appears that the risk to the environment from coal gasification plants can be acceptable with current technology. Most sponsors view the environmental impact of coal gasification plants as less than that of direct

coal combustion and similar to that of petroleum refining, both of which are currently environmentally acceptable. Detailed environmental monitoring at pilot plants indicates that commercial-size plants can meet current effluent standards. The cost of meeting standards has been factored into published production cost estimates. These environmental studies have relied on engineering estimates and scale-up data from pilot plants, as no commercial facility is yet in operation. Proving acceptable environmental impact to the satisfaction of regulatory agencies, however, may pose a significant impediment.

A secondary environmental issue is the cost of complying with future regulations, such as solid waste disposal under the Resource Conservation and Recovery Act. However, these contingencies are not expected to increase the production cost more than 5 percent, according to preliminary studies by architect/engineering firms.

2. THE FINANCIAL BARRIERS STEM FROM THE SIZE OF THE PROJECTS AND THE NATURE OF THE PARTICIPANTS

Regulation of the pipelines and utilities considering these projects strongly impacts the investment criteria of these firms, particularly with respect to cost of service considerations and risk aversion. Because these companies provide a public service, they do not, by nature, invest in risky enterprises that may impact the viability of the basic business. Because their investments are traditionally low risk (i.e., demand for product is built in by the monopolistic position of the company within its service area), rates of return on capital have generally been lower than for unregulated industries.

Thus, basic financial barriers that surround high-Btu coal gasification plants are:

- . The size of the capital investment required
- . The risk premium necessary to stimulate such investment
- . The ability to recover financially if the project is not completed.

Current estimates of the cost of coal gasification plants are in the range of \$1.3 to \$1.8 billion. Such an investment nearly always dictates joint sponsorship in order to dilute the financial risk. In general, the gas industry has not dealt with such capital intensive means of gas production, with the exception of LNG projects. Structuring a project, then, requires financing different from the normal capital investments of pipeline and distribution companies.

Natural gas supply has traditionally been the function of independent production companies or of unregulated subsidiaries of pipelines because of the risk associated with exploration and development. These companies have undertaken production efforts only when the potential rewards compensate for the risk; that is, when the projected rate of return is increased to account for uncertainty. Although a coal gasification project does not possess the same type of risk as exploration and development, it is, nevertheless, considerably more risky than traditional utility investments, due to the technical, environmental, and institutional uncertainties discussed above. Project sponsors feel that the acceptable rate of return for such a project should be increased to account for the greater risks.

A third financial barrier is the inability of participants to absorb potential financial losses arising from non-completion of a high-Btu gas project. The industry has yet to develop prescribed measures for the recovery of debt and equity should the project be terminated. Project sponsors are generally willing to absorb only the technical risk and they foresee a number of scenarios under which a technically-feasible project is not allowed to continue to operate. Potential sponsors wish to be insulated from these non-technical reasons for non-completion.

A number of mechanisms have been proposed to mitigate financial risk, including:

- . Loan guarantees for project debt
- . The adoption of rolled-in pricing
- . Joint ventures to spread risk among several organizations
- . Project financing to limit liability
- . Guaranteed capital recovery proposals (customer surcharge, all events tariff, CWIP, etc.).

The industry consensus is that these measures, or similar mechanisms, are necessary to attract the capital for the first few plants. Potential sponsors are concerned, however, that the terms and conditions of these measures be responsive to their needs. Other potential sponsors argue for additional incentives in order to stimulate investment in coal gasification. Many proposed incentives are seen as less effective. For example, most sponsors would not be able to absorb an additional investment tax credit or more rapid depreciation unless they participate in a joint venture. A few sponsors desire a guaranteed purchase price. Others see such a scheme as very difficult to administer, especially if Federal funds are provided based on competitive bids.

3. INSTITUTIONAL BARRIERS HAVE HAD MAJOR IMPACTS ON PREVIOUS COAL GASIFICATION PROJECTS

Institutional barriers result in two types of risks which reduce the attractiveness of investment in high-Btu coal gasification plants:

- . Uncertainty as to the ability to complete and operate a proposed plant
- . Uncertain economic impact of future regulations.

The regulatory process involves a number of state, local and Federal agencies which have a variety of mandates and criteria for reviewing and approving/disapproving projects. Environmental legislation, implementing regulations and court decisions have placed some areas of the country off limits to energy development, and have raised the possibility that some future sites will be found unacceptable. In addition, other governmental bodies have de facto ability to disapprove projects.

Even if a plant is built, its resulting operational reliability and economics are highly uncertain. The future effects of as-yet undefined implementing regulations for recent legislation, such as the Resource Conservation and Recovery Act, are unknown. The tariffs and capitalization treatment of future projects is also subject to revision. Thus, project sponsors are forced to deal with major uncertainties, which can only be handled through order of magnitude estimates and contingency analyses. The barriers discussed in this section of the report are summarized in Exhibit V-2.

EXHIBIT V-2
Coal Gasification Projects:
Barriers and Solutions

TYPES OF BARRIERS	PRIORITY	EXAMPLES	APPROACHES TO SOLUTION
TECHNOLOGICAL	2	. Lack of Demonstrated Reliability of a Fully Integrated Facility	. Design for Reliability
	2	. Inability to Gasify Highly Caking Coals with Equipment That is Currently Available	. Qualified Engineers Opinion in Proposed Financing . Guaranteed Capital Recovery in Case of Failure - Loan Guarantees - Customer Surcharges for Equity - All Event Tariffs . Demonstration of Second Generation Processes with Federal Funding
FINANCIAL	2	. Inability to Provide Price Sufficient to Amortize all Investment and Provide Reasonable Rate of Return	. Rolled in Pricing
	3	. Inability to Guarantee Demand in Light of Other Supplemental Sources	. Federal Policy Discouraging Imports . Prove Need for Project in ERA Application
	2	. Inability of Participants to Absorb Potential Losses	. Joint Venture . Project Financing . Guaranteed Capital Recovery
INSTITUTIONAL	1	. Uncertainty as to Ability to Complete and Operate Plant	. Expedited Siting & Environmental Permits for Plant & Coal Mine - Air Quality - Water Quality - Water Use - Land Use
	3	. Uncertain Economic Impact of Future Unforeseen Environmental Regulations	. Guaranteed Pass Through/Rate of Return

PRIORITY KEY:

1 = High
2 = Moderate
3 = Low

4. SELECTED INCENTIVES CAN BE EFFECTIVE IN STIMULATING COAL GASIFICATION

It is worth noting that some of the coal gasification projects were proposed as early as 1970. They have reached various stages of development, but none has reached the construction phase. The renewed interest in synthetic fuels has resulted in several incentives proposals. These proposed incentives were discussed with members of the gas industry. The following section presents the opinions of a variety of potential high-Btu coal gasification project sponsors. It should be noted that, just as there is no universal gasifier, there is no unanimous industry opinion of the effectiveness of various incentives.

(1) Individuals From Potential Sponsoring Organizations Felt That the Concept of an Energy Mobilization Board Was an Important Step

Most sponsors felt that inordinate delays in the courts or in regulatory bodies had ended several projects and rendered the economics of others unworkable. One company stated their inability to obtain the necessary permits in a timely fashion led to the corporate decision to discontinue the project. Another company stated that had they been able to commence construction of a plant as originally scheduled; that plant would now be providing gas at \$3.72/MCF instead of the current projection of \$5-6/MCF.

While praising the concept of energy project expediting, some sources in the gas industry have adopted a "wait-and-see" attitude toward any legislative accomplishments. It has been noted by some that expedited decisions may merely become early vetoes. Others note that if the criteria for judicial review are not specified, any Board decision may be subject to the same delays that have affected current projects.

Comments on environmental regulation indicated that potential participants seek regulatory stability, not relaxation of current environmental standards. These companies are seeking to reduce the risk attendant to a project that represents a major capital investment. In order to do so, they feel they need established criteria for making investment decisions, citing in particular, environmental criteria. An example cited by one company was a state board which has broad authority to judge "acceptable impact"

without providing criteria or guidelines for either the public utility commissioners or plant sponsors. Each new proposed project in the state has entailed an increase in measures to mitigate socioeconomic impacts (e.g., provide a municipal wastewater treatment facility for a nearby town, establish an internal training program for employees.) This company highlighted the inability to assess the economics of future plants in the state because of the incremental requirements that result from each successive filing.

(2) Sponsors Felt That Once the Institutional Problems Are Solved, Minimal Financial Incentives Are Necessary

Loan guarantees rate a high priority as a financial incentive. Because of the size of proposed projects relative to sponsors' equity and the regulatory uncertainty discussed above, financial backers will be unwilling to commit funds until they foresee a significant reduction of risk. The most realistic measure appears to be Federal loan guarantees which may reduce the risk of a project to a level low enough to attract private sector funds. If the terms of the guarantees can be made acceptable to the borrower, it appears that some private sector funds will be forthcoming for high-Btu coal gasification projects.

The other major incentive desired by sponsors is rolled-in pricing. As stated previously, several project sponsors felt they could absorb 10-20 percent of their total supply from coal gas, if the price were rolled-in. Our analysis (Chapter II of this report) showed that in the 1990's, under rolled-in pricing, high-Btu coal gas is expected to compete with most alternatives in a variety of uses. Project sponsors are thus hopeful that FERC will exempt coal gas from the incremental pricing provisions of the Natural Gas Policy Act based on determination of a high cost source.

(3) The Reaction to Price Guarantees Was Mixed

A guaranteed price was viewed by several as an effective measure to contain the market risk of this high-cost fuel. Proponents of this incentive see the possibility of market price declines as the major market barrier to high-Btu coal gas. A guaranteed purchase would insulate projects from the risk from either major new gas finds or predatory pricing by oil exporting countries.

Opponents of price guarantees counter that prices can be made competitive now (under rolled-in pricing) and that any price guarantee scheme will be administratively burdensome. The administrative requirements of a price guarantee result basically from the competitive bid procedure, which invites shaving of cost estimates in order to gain a toehold in a new market. Any subsequent cost overruns may be viewed by the public entity as within the scope of the original proposal. When compounded by the legitimate role of Congress to review its programs, revising established laws as necessary to effect the public welfare, many potential project sponsors view a purchase guarantee as an open-end risk which can be better handled by other means.

(4) The Proposal for a GOCO (Government-Owned Contractor-Operated) Facility Met With Considerable Resistance

The principal advantage of the GOCO is its ability to pursue projects too large and too risky for the private sector and to utilize low-cost funds. Many of the individuals interviewed felt that the conditions that argue for a GOCO are not extant in the case of coal gas, as many of the successful GOCO's were established during wartime when a crash effort was required, but demand beyond a certain date was expected to diminish. In contrast, in the case of coal gas, as well as other synthetic fuels, current demand is highly uncertain, and the long-term outlook is bright. In addition, other GOCO's often involved new technology, which was untried. In contrast, coal gasification uses commercially available technology.

Under such circumstances, GOCO's are not seen as optimal resource allocation mechanisms. Most individuals interviewed felt that the profit motive of private corporations would ensure that only efficient processes are carried along, whereas the government selection process could be subject to partisan politics. Additionally, these individuals felt that private incentive compensation systems tied to the profit motive could overcome any differential in constructed cost due to the low cost of Federal funds.

Finally, individuals interviewed noted that GOCO's will ensure more government intervention in energy markets. The appropriate amount and type of intervention is, of course, contested by various parties.

(5) Reactions to Other Possible Incentives Were Mixed

Because of the size of coal gasification projects relative to the size of sponsoring organizations, additional tax benefits, such as an investment tax credit or rapid amortization, may not be effective. Tax benefits are effective only if the sponsoring organization earns enough income to shield. In the case of coal gas, plants are estimated to cost \$1.3-1.8 billion. During the initial year of operation, a sponsor would be eligible for approximately \$150 million in investment tax credit and depreciation of \$100-150 million. A typical net income for an interstate transmission company is about \$100 million per year, which is not equal to the potential \$300 million tax benefit. While it is true that the tax credit can be carried forward to future years (depreciation cannot), the credit loses some of its effectiveness because of the time-value of money.

Another proposal has been immediate expensing of capital. Under this scenario, a company could immediately write off its capital investment as expended, i.e., during the construction period. Even though a single company may not be able to reap the full annual benefits, cash flows would be advanced by up to 5 years, thereby greatly increasing their value. Through a joint venture of several companies, the full benefits could be taken by prorating.

Including CWIP—Construction Work in Progress—in the rate base of regulated companies also aids the economics. By including CWIP in its cost-of-service rate basis, the utility can earn a rate of return on this asset. The specified rate is at least adequate to cover the cost of financing, which may comprise one-quarter of the total capital cost. The use of CWIP effectively reduces the required selling price of the plant output through reducing the capital cost. In addition, it eases the financing burden on regulated utilities.

* * * * *

This section has outlined major barriers affecting high-Btu gas from coal and incentives that would be potentially effective in overcoming these barriers. It is important to note that no single incentive will solve all problems. Additionally, while there is consensus within the industry on the effectiveness of some incentives, there is a healthy

disagreement on the value of others. Exhibit V-3 summarizes the findings on relative attractiveness of incentives. It appears that a variety of the more promising incentives should be offered in order to allow each potential sponsor to develop a package that is most suitable to its specific needs.

EXHIBIT V-3
Summary of Incentives Applicable to High-Btu
Coal Gasification Plants

High Priority

Rolled-In Pricing
Loan Guarantees
Expedited Project Permitting
Completion Guarantee

Moderate Priority

Price or Purchase Guarantee
Production Credit
Additional Investment Tax Credit
Rapid Amortization
All Events Tariff
CWIP in Rate Base

Low Priority

GOCO (Government-Owned, Contractor-Operated Facilities)
Production Mandates

EXHIBIT A-1
Projected Energy Consumption by Fuel Type
Base Case - 1985
(Quadrillion Btu per year)

	NEW ENGLAND	NEW YORK NEW JERSEY	MID ATLANTIC	SOUTH ATLANTIC	MIDWEST	SOUTHWEST	CENTRAL	NORTH CENTRAL	WEST	NORTH- WEST	TOTAL
<u>RESIDENTIAL</u>											
Electricity	.12	.18	.27	.69	.51	.34	.15	.08	.28	.19	2.81
Distillate	.38	.60	.29	.13	.43	.04	.05	.02	.02	.05	2.01
Liquid Gas	.01	.01	.02	.10	.11	.09	.08	.04	.02	.01	0.49
Natural Gas	.17	.51	.49	.37	1.71	.56	.43	.20	.62	.07	5.13
Coal	n	n	.02	n	.01	-	n	.01	.01	n	0.05
	.68	1.30	1.09	1.29	2.77	1.03	.71	.35	.95	.32	10.49
<u>COMMERCIAL</u>											
Electricity	.15	.30	.25	.43	.45	.32	.17	.10	.29	.14	2.60
Distillate	.12	.09	.06	.04	.11	.08	.02	.01	.01	.03	0.57
Residual	.10	.27	.06	.03	.07	.01	.01	.01	.01	.01	0.58
Natural Gas	.12	.18	.20	.32	.55	.35	.18	.10	.24	.08	2.32
Other ¹	.04	.08	.11	.23	.28	.12	.09	.07	.13	.05	1.20
	.53	.92	.68	1.05	1.46	.88	.47	.28	.68	.31	7.27
<u>INDUSTRIAL</u>											
Electricity	.07	.22	.39	.91	.97	.69	.12	.07	.31	.21	3.96
Distillate	n	.01	.11	.05	.07	.14	.01	.01	.04	.01	0.45
Residual	.09	.08	.03	.01	.12	.01	n	n	.03	.02	0.39
Coal ²	.13	.23	1.25	.69	1.84	.60	.15	.20	.08	.11	5.28
Natural Gas	.29	.18	.65	1.16	1.22	3.72	.35	.38	1.04	.27	9.26
Liquid Gas	.02	.01	.04	.05	.16	.06	.07	.02	.01	.01	0.45
Naptha	.03	.06	.02	.01	.14	.31	n	-	.02	-	0.59
	.63	.79	2.49	2.88	4.52	5.53	.70	.68	1.53	.63	20.38
<u>MISCELLANEOUS</u> ³	.03	.20	.34	.47	.74	3.53	.27	.12	.57	.20	6.47
<u>TOTAL</u>	1.87	3.21	4.60	5.69	9.49	10.97	2.15	1.43	3.73	1.46	44.61

NOTE: Due to independent rounding individual components may not sum to totals shown.
Solar energy excluded.

Source: MEPS C High Case, with adjustments in aggregation as noted below.

n: Negligible

1: Includes coal, liquid gas, and asphalt.

2: Includes metallurgical coal.

3: Includes refinery fuel consumption and fuels used as feedstocks and raw materials.

EXHIBIT A-2
Projected Energy Consumption by Fuel Type
Base Case - 1990
(Quadrillion Btu per year)

	NEW ENGLAND	NEW YORK NEW JERSEY	MID ATLANTIC	SOUTH ATLANTIC	MIDWEST	SOUTHWEST	CENTRAL	NORTH CENTRAL	WEST	NORTH- WEST	TOTAL
<u>RESIDENTIAL</u>											
Electricity	.14	.19	.31	.82	.58	.40	.18	.09	.38	.22	3.32
Distillate	.39	.60	.30	.12	.40	.03	.04	.02	.01	.04	1.95
Liquid Gas	.01	.01	.01	.08	.11	.07	.07	.03	.02	.01	0.43
Natural Gas	.18	.55	.53	.40	1.82	.61	.46	.21	.59	.07	5.43
Coal	-	-	.01	-	-	-	-	-	-	-	0.03
	.76	1.39	1.18	1.42	2.89	1.10	.74	.36	.98	.35	11.17
<u>COMMERCIAL</u>											
Electricity	.20	.36	.29	.47	.50	.36	.19	.11	.32	.15	2.96
Distillate	.10	.07	.05	.03	.08	.06	.01	.01	.01	.02	0.44
Residual	.09	.21	.04	.02	.05	.01	.01	.01	.01	.01	0.44
Natural Gas	.12	.20	.23	.37	.52	.35	.16	.10	.22	.09	2.37
Other ¹	.04	.08	.10	.24	.29	.12	.08	.07	.14	.05	1.21
	.58	.95	.71	1.12	1.43	.90	.45	.30	.68	.33	7.42
<u>INDUSTRIAL</u>											
Electricity	.07	.26	.49	1.17	1.23	.94	.16	.13	.39	.25	5.05
Distillate	-	.01	.11	.06	.06	.17	.01	.01	.04	.01	0.48
Residual	.14	.10	.13	.04	.33	.01	-	-	.12	.03	0.90
Coal	.17	.28	1.32	.98	2.05	1.35	.21	.27	.18	.20	7.01
Natural Gas	.21	.12	.55	1.13	.87	3.82	.35	.33	1.07	.24	8.75
Liquid Gas	.02	.01	.04	.06	.19	.07	.08	.02	.01	.01	0.52
Naptha	.03	.08	.02	.02	.17	.40	-	-	.03	-	0.74
	.77	.91	2.64	3.36	4.96	6.59	.79	.73	1.91	.73	23.45
<u>MISCELLANEOUS</u> ³	.04	.23	.41	.62	.93	4.43	.32	.14	.70	.26	8.09
<u>TOTAL</u>	2.15	3.43	4.94	6.52	10.20	13.02	2.30	1.53	4.28	1.67	50.13

NOTE: Due to independent rounding individual components may not sum to totals shown.
Solar energy excluded.

Source: MEFS C High Case, with adjustments in aggregation as noted below.

n: Negligible

1: Includes coal, liquid gas, and asphalt.

2: Includes metallurgical coal.

3: Includes refinery fuel consumption and fuels used as feedstocks and raw materials.

EXHIBIT A-3
Projected Energy Consumption by Fuel Type
Base Case - 1995
(Quadrillion Btu per year)

	NEW ENGLAND	NEW YORK NEW JERSEY	MID ATLANTIC	SOUTH ATLANTIC	MIDWEST	SOUTHWEST	CENTRAL	NORTH CENTRAL	WEST	NORTH- WEST	TOTAL
<u>RESIDENTIAL</u>											
Electricity	.17	.21	.35	.95	.64	.46	.21	.11	.45	.25	3.76
Distillate	.36	.55	.28	.10	.33	.02	.03	.02	-	.04	1.73
Liquid Gas	.01	.02	.02	.07	.09	.06	.06	.06	.03	.01	0.37
Natural Gas	.19	.56	.56	.43	1.87	.65	.47	.22	.62	.07	5.65
Coal	-	-	.01	-	-	-	-	-	.01	-	0.02
	<u>.77</u>	<u>1.39</u>	<u>1.22</u>	<u>1.53</u>	<u>2.93</u>	<u>1.16</u>	<u>.75</u>	<u>.37</u>	<u>1.04</u>	<u>.36</u>	<u>11.54</u>
<u>COMMERCIAL</u>											
Electricity	.29	.41	.32	.54	.56	.42	.22	.12	.35	.17	3.37
Distillate	.08	.06	.04	.02	.06	.05	.01	.01	-	.02	0.35
Residual	.07	.16	.03	.02	.04	.01	-	.01	-	.01	0.35
Natural Gas	.12	.20	.25	.46	.49	.38	.15	.11	.26	.10	2.52
Other ¹	.04	.08	.10	.26	.30	.13	.08	.07	.15	.06	1.27
	<u>.61</u>	<u>.97</u>	<u>.75</u>	<u>1.27</u>	<u>1.44</u>	<u>.96</u>	<u>.46</u>	<u>.31</u>	<u>.75</u>	<u>.35</u>	<u>7.86</u>
<u>INDUSTRIAL</u>											
Electricity	.09	.33	.61	1.53	1.55	1.28	.22	.13	.50	.30	6.54
Distillate	-	.01	.09	.05	.04	.20	.01	.02	.05	.01	0.47
Residual	.22	.15	.29	.17	.67	.02	.02	-	.16	.05	1.77
Coal ²	.24	.34	1.47	1.45	2.33	2.42	.28	.39	.27	.28	9.47
Natural Gas	.15	.08	.47	.97	.70	4.19	.35	.40	1.07	.24	8.62
Liquid Gas	.03	.01	.04	.07	.21	.08	.09	.03	.01	.01	0.57
Naptha	.04	.09	.03	.02	.21	.50	-	-	.03	-	0.92
	<u>.88</u>	<u>1.06</u>	<u>3.04</u>	<u>4.19</u>	<u>5.87</u>	<u>8.41</u>	<u>.96</u>	<u>.94</u>	<u>2.13</u>	<u>.88</u>	<u>28.36</u>
<u>MISCELLANEOUS</u> ³	.05	.27	.46	.71	1.00	4.93	.35	.16	.72	.28	8.93
<u>TOTAL</u>	2.31	3.69	5.47	7.70	11.24	15.46	2.52	1.78	4.64	1.87	56.69

NOTE: Due to independent rounding individual components may not sum to totals shown.
Solar energy excluded.

Source: MEFS - High Case, with adjustments in aggregation as noted below.

n: Negligible

1: Includes coal, liquid gas, and asphalt.

2: Includes metallurgical coal.

3: Includes refinery fuel consumption and fuels used as feedstocks and raw materials.

EXHIBIT A-4
Projected Energy Consumption by Fuel Type
Base Case - 2000
(Quadrillion Btu per year)

	NEW ENGLAND	NEW YORK NEW JERSEY	MID ATLANTIC	SOUTH ATLANTIC	MIDWEST	SOUTHWEST	CENTRAL	NORTH CENTRAL	WEST	NORTH- WEST	TOTAL
<u>RESIDENTIAL</u>											
Electricity	.20	.22	.37	.09	.70	.50	.24	.13	.52	.29	4.26
Distillate	.35	.52	.26	.08	.27	.01	.02	.02	-	.04	1.57
Liquid Gas	.01	.02	.02	.06	.08	.05	.05	.05	.03	.01	.38
Natural Gas	.20	.57	.58	.46	1.93	.69	.49	.24	.64	.07	5.87
Coal	-	-	.01	-	-	-	-	-	.01	-	.02
	.76	1.33	1.24	.69	2.98	1.25	.80	.44	1.20	.41	12.10
<u>COMMERCIAL</u>											
Electricity	.33	.45	.35	.58	.60	.45	.28	.14	.37	.18	3.73
Distillate	.06	.05	.03	.02	.05	.04	.01	.01	-	.02	.29
Residual	.06	.13	.03	.02	.04	.01	.03	.01	-	.01	.34
Natural Gas	.12	.19	.27	.56	.47	.39	.13	.12	.28	.10	2.63
Other ¹	.04	.08	.10	.29	.31	.14	.08	.07	.16	.07	1.34
	.61	.90	.78	1.47	1.47	1.03	.53	.35	.81	.38	8.33
<u>INDUSTRIAL</u>											
Electricity	.11	.36	.65	1.65	1.70	1.51	.27	.16	.59	.34	7.34
Distillate	-	.01	.08	.04	.04	.23	.01	.02	.05	.01	.49
Residual	.27	.17	.35	.20	.79	.02	.01	-	.22	.07	2.10
Coal ²	.33	.37	1.60	1.65	2.50	3.10	.34	.48	.34	.37	11.08
Natural Gas	.09	.06	.40	.90	.62	4.35	.35	.40	1.11	.23	8.51
Liquid Gas	.03	.01	.04	.07	.23	.09	.09	.03	.02	.01	.62
Naptha	.04	.10	.03	.02	.25	.57	-	-	.04	-	1.05
	.87	1.08	3.15	4.53	6.13	9.87	1.07	1.09	2.37	1.03	31.19
<u>MISCELLANEOUS³</u>	.06	.30	.50	.81	1.11	5.25	.39	.17	.75	.31	9.65
<u>TOTAL</u>	2.30	3.61	5.67	8.50	11.69	17.40	2.79	2.05	5.13	2.13	61.27

NOTE: Due to independent rounding individual components may not sum to totals shown.
Solar energy excluded.

Source: Extrapolation of MEFS C High growth rates 1990-1995 to 1995-2000 period.

n: Negligible

1: Includes coal, liquid gas, and asphalt.

2: Includes metallurgical coal.

3: Includes refinery fuel consumption and fuels used as feedstocks and raw materials.

EXHIBIT A-5
Projected Average Annual Growth Rates in Energy Consumption (%)
1985 - 2000

	<u>NEW ENGLAND</u>	<u>NEW YORK NEW JERSEY</u>	<u>MID ATLANTIC</u>	<u>SOUTH ATLANTIC</u>	<u>MIDWEST</u>	<u>SOUTHWEST</u>	<u>CENTRAL</u>	<u>NORTH CENTRAL</u>	<u>WEST</u>	<u>NORTH WEST</u>	<u>TOTAL</u>
<u>RESIDENTIAL</u>											
Electricity	3.5	1.3	2.1	3.1	2.1	2.6	3.2	3.3	4.2	2.9	2.8
Distillate	-0.5	-0.9	-0.7	-3.2	-3.1	-8.8	-5.9	0.0	-	-1.5	-1.6
Liquid Gas	-	4.7	-	-3.3	-2.1	-3.8	-3.1	1.5	2.7	-	-1.7
Natural Gas	-1.1	0.7	1.1	1.5	0.8	1.4	0.9	1.2	0.2	0.0	0.9
Coal	-	-	-4.5	-	-	-	-	-	-	-	-5.9
	<u>0.7</u>	<u>0.2</u>	<u>0.9</u>	<u>1.8</u>	<u>0.5</u>	<u>1.3</u>	<u>0.8</u>	<u>1.5</u>	<u>1.6</u>	<u>1.7</u>	<u>1.0</u>
<u>COMMERCIAL</u>											
Electricity	5.4	2.7	2.3	2.0	1.9	2.3	3.4	2.3	1.6	1.7	2.4
Distillate	-4.5	-3.8	-4.5	-4.5	-5.1	-4.5	-4.5	-	-	-7.1	-4.6
Residual	-3.3	-4.8	-4.5	-2.7	-3.7	-	7.6	-	-	-	-3.5
Natural Gas	-	0.4	2.0	3.8	-1.0	0.7	-2.1	1.2	1.0	1.5	0.8
Other ¹	-	-	-0.6	1.6	0.7	1.0	-0.8	0.0	1.4	2.3	0.7
	<u>0.9</u>	<u>-0.1</u>	<u>0.9</u>	<u>2.3</u>	<u>-</u>	<u>1.1</u>	<u>0.8</u>	<u>1.5</u>	<u>1.2</u>	<u>1.4</u>	<u>0.9</u>
<u>INDUSTRIAL</u>											
Electricity	3.1	3.3	3.5	4.0	3.8	5.4	5.6	5.7	4.4	3.3	4.2
Distillate	-	-	-2.1	-1.5	-3.7	3.4	-	4.7	1.5	-	0.6
Residual	7.6	5.2	17.8	22.1	13.4	4.7	-	-	14.2	8.7	11.9
Coal ²	6.4	3.2	1.7	6.0	4.9	11.6	5.6	6.0	10.1	8.4	5.1
Natural Gas	-7.5	-7.1	-3.2	-1.7	-7.0	1.0	-	0.3	0.4	-1.1	-0.6
Liquid Gas	2.7	-	-	2.3	-4.4	2.7	1.7	2.7	4.7	-	2.2
Naptha	1.9	1.9	2.7	4.7	3.9	4.1	-	-	4.7	-	3.9
	<u>2.2</u>	<u>2.1</u>	<u>1.6</u>	<u>3.1</u>	<u>2.1</u>	<u>3.9</u>	<u>3.5</u>	<u>3.2</u>	<u>3.0</u>	<u>3.3</u>	<u>2.9</u>
<u>MISCELLANEOUS</u> ³	4.7	2.7	2.6	3.7	2.8	2.7	2.5	2.3	1.8	3.0	2.7
<u>TOTAL</u>	1.4	0.8	1.4	2.7	1.4	3.1	1.8	2.4	2.1	2.5	2.1

- NOTE: 1. Due to independent rounding individual components may not sum to totals shown.
2. Solar energy excluded.
1. Includes coal, liquid gas, and asphalt.
2. Includes metallurgical coal.
3. Includes refinery fuel consumption and fuels used as feedstocks and raw materials.

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EXHIBIT B-1
Projected Energy Prices by Fuel Type
Base Case - 1985
(1978 Dollars per MMBtu)

	<u>New England</u>	<u>New York New Jersey</u>	<u>Mid Atlantic</u>	<u>South Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>Residential</u>											
Electricity	\$15.17	\$16.95	\$14.10	\$11.51	\$13.25	\$14.02	\$12.33	\$11.98	\$14.11	\$5.83	\$12.91
Distillate	4.76	4.85	5.10	5.19	4.50	4.76	4.39	4.58	4.75	4.75	4.80
Liquid Gas	5.02	5.14	5.56	5.59	4.92	4.97	4.77	5.10	4.21	4.21	5.05
Natural Gas	4.79	4.31	3.84	3.38	3.32	3.36	3.11	3.44	4.09	4.56	3.62
<u>Commercial</u>											
Electricity	14.80	17.03	13.25	11.93	13.12	12.97	11.66	10.61	12.48	6.03	12.88
Distillate	4.43	4.53	4.58	4.58	4.25	4.42	4.16	4.26	4.38	4.38	4.42
Residual	3.61	3.74	4.15	3.65	3.68	3.66	3.70	3.52	3.60	3.51	3.73
Natural Gas	4.08	3.67	3.34	2.84	2.97	2.80	2.68	3.19	3.54	3.93	3.15
<u>Industrial</u>											
Electricity	11.29	9.94	10.26	8.54	9.42	10.27	9.03	7.35	10.22	3.12	9.27
Distillate	4.59	4.66	4.86	4.85	4.40	4.55	4.29	4.47	4.33	4.33	4.63
Residual	3.83	4.02	4.20	3.73	3.79	3.79	3.79	3.58	3.63	3.70	3.87
Coal	2.08	2.20	2.18	2.10	2.07	1.78	1.64	1.93	2.86	1.90	2.07
Natural Gas ^a	3.80	3.33	3.32	2.92	3.11	2.71	2.86	2.94	3.42	3.51	3.00

^a Includes a surcharge for low priority industrial users which is projected to range from 29¢/MMBtu in 1985 to 79¢/MMBtu in 1995, with regional variation.

Source: National total prices from MEFS C High Case; Regional data estimated under the assumption that the known relationship between the individual regions and the national total in the MEFS Mid Case are the same as in the MEFS C High Case.

EXHIBIT B-2
Projected Energy Prices by Fuel Type
Base Case - 1990
(1978 Dollars per MMBtu)

	<u>New</u> <u>England</u>	<u>New York</u> <u>New Jersey</u>	<u>Mid</u> <u>Atlantic</u>	<u>South</u> <u>Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North</u> <u>Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>Residential</u>											
Electricity	\$15.45	\$16.78	\$14.25	\$11.77	\$13.45	\$14.92	\$11.81	\$11.04	\$14.40	\$ 6.24	\$12.96
Distillate	5.24	5.36	5.58	5.66	5.04	5.28	4.94	5.11	4.91	4.91	5.30
Liquid Gas	5.65	5.76	6.15	6.22	5.67	5.74	5.55	5.84	4.90	4.90	5.76
Natural Gas	5.02	4.65	4.06	3.53	3.61	3.64	3.47	3.59	4.40	4.73	3.89
<u>Commercial</u>											
Electricity	15.11	16.86	13.40	12.18	13.23	13.92	11.16	9.70	12.78	6.44	12.99
Distillate	4.94	5.05	5.10	5.10	4.82	4.95	4.72	4.83	4.56	4.56	4.94
Residual	4.09	4.21	4.59	4.10	4.19	4.12	4.18	4.02	3.74	3.65	4.20
Natural Gas	4.34	4.03	3.58	3.00	3.27	3.10	3.06	3.36	3.87	4.13	3.43
<u>Industrial</u>											
Electricity	11.60	9.91	10.36	8.82	9.57	11.21	8.52	6.48	10.42	3.60	9.47
Distillate	4.78	4.87	5.06	5.04	4.66	4.78	4.56	4.71	4.62	4.62	4.82
Residual	4.04	4.21	4.36	3.94	4.04	3.98	4.02	3.84	3.85	3.90	4.03
Coal	2.24	2.30	2.31	2.19	2.21	1.86	1.72	1.82	2.51	1.91	2.11
Natural Gas ^a	4.09	4.01	4.00	3.58	3.94	3.04	3.68	3.13	3.78	3.74	3.44

^a Includes a surcharge for low priority industrial users which is projected to range from 29¢/MMBtu in 1985 to 79¢/MMBtu in 1995, with regional variation.

Source: National total prices from MEFS C High Case; Regional data estimated under the assumption that the known relationship between the individual regions and the national total in the MEFS Mid Case are the same as in the MEFS C High Case.

EXHIBIT B-3
Projected Energy Prices by Fuel Type
Base Case - 1995
(1978 Dollars per MMBtu)

	<u>New</u> <u>England</u>	<u>New York</u> <u>New Jersey</u>	<u>Mid</u> <u>Atlantic</u>	<u>South</u> <u>Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North</u> <u>Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>Residential</u>											
Electricity	\$15.34	\$16.63	\$14.48	\$12.20	\$13.98	\$15.27	\$11.98	\$11.40	\$14.74	\$6.57	\$13.36
Distillate	6.63	6.76	7.00	7.10	6.46	6.68	6.33	6.48	6.21	6.21	6.71
Liquid Gas	7.38	7.49	7.88	7.97	7.40	7.45	7.24	7.58	6.60	6.60	7.48
Natural Gas	5.48	5.24	4.47	3.75	4.18	4.30	4.15	4.15	4.36	5.14	4.36
<u>Commercial</u>											
Electricity	14.98	16.70	13.68	12.61	13.76	14.24	11.32	10.05	13.13	6.77	13.37
Distillate	6.32	6.43	6.50	6.51	6.22	6.36	6.11	6.19	5.84	5.84	6.32
Residual	5.11	5.22	5.61	5.14	5.24	5.17	5.22	5.03	4.64	4.55	5.22
Natural Gas	4.79	4.62	3.99	3.22	3.84	3.74	3.72	3.91	3.82	4.52	3.85
<u>Industrial</u>											
Electricity	11.20	9.47	10.45	9.03	9.84	11.27	8.54	6.65	10.89	3.81	9.67
Distillate	6.54	6.64	6.86	6.84	6.44	6.56	6.31	6.47	6.05	6.05	6.57
Residual	5.35	5.55	5.71	5.29	5.41	5.34	5.37	5.13	4.81	4.87	5.38
Coal	2.38	2.40	2.42	2.27	2.27	1.95	1.81	1.77	2.83	2.01	2.18
Natural Gas ^a	5.06	5.05	5.05	4.96	5.00	3.68	4.93	3.66	4.62	4.62	4.24

^a Includes a surcharge for low priority industrial users which is projected to range from 29¢/MMBtu to 79¢/MMBtu in 1995, with regional variation

Source: National total prices from MEFS C High Case; Regional data estimated under the assumption that the known relationship between the individual regions and the national total in the MEFS Mid Case are the same as in the MEFS C High Case.

EXHIBIT B-4
Projected Energy Prices by Fuel Type
Base Case - 2000
(1978 Dollars per MMBtu)

	<u>New England</u>	<u>New York New Jersey</u>	<u>Mid Atlantic</u>	<u>South Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>Residential</u>											
Electricity	\$15.34	\$16.48	\$14.94	\$12.65	\$14.53	\$15.63	\$12.15	\$12.46	\$15.80	\$6.92	\$13.77
Distillate	8.39	8.53	8.78	3.91	8.28	8.45	8.11	8.22	7.85	7.85	8.50
Liquid Gas	9.64	9.74	10.10	10.21	9.66	9.67	9.44	9.84	8.89	8.89	9.71
Natural Gas	5.98	5.90	4.92	3.98	4.84	5.08	4.96	4.80	4.32	5.59	4.89
<u>Commercial</u>											
Electricity	14.98	16.54	14.15	13.06	14.31	14.57	11.48	10.41	14.10	7.12	13.76
Distillate	8.09	8.19	8.28	8.31	8.03	8.17	7.91	7.93	7.48	7.48	8.09
Residual	6.38	6.47	6.86	6.44	6.55	6.49	6.52	6.29	5.76	5.67	6.49
Natural Gas	5.29	5.30	4.45	3.46	4.51	4.51	4.52	4.55	3.77	4.95	4.32
<u>Industrial</u>											
Electricity	11.20	9.47	10.56	9.24	10.12	11.33	8.54	6.82	11.58	4.03	9.87
Distillate	8.95	9.05	9.30	9.28	8.90	9.00	8.73	8.89	8.28	8.28	8.96
Residual	7.08	7.32	7.48	7.10	7.24	7.16	7.17	6.85	6.39	6.42	7.18
Coal	2.53	2.50	2.54	2.35	2.33	2.04	1.90	1.72	3.19	2.12	2.25
Natural Gas ^a	6.26	6.36	6.38	5.87	6.35	4.45	6.60	4.28	5.65	5.71	5.23

^a Includes a surcharge for low priority industrial users which is projected to range from 29¢/MMBtu in 1985 to 79¢/MMBtu in 1995, with regional variation.

APPENDIX C. BREAK-EVEN ANALYSIS

This appendix presents the assumptions and information used to perform the break-even analysis of high-Btu gas in typical residential, commercial, and industrial systems. Eleven applications were chosen to represent the broad spectrum of gas-consuming facilities:

- . Residential sector: Single family dwellings
- . Commercial sector:
 - Multifamily dwellings
 - Office buildings
 - Retail stores
 - Schools
- . Industrial sector:
 - Boilers
 - Brick kilns
 - Cement kilns
 - Glass furnaces
 - Steel reheat furnaces
 - Food processing ovens.

Comparisons were made between high-Btu gas and coal, oil, and electricity where appropriate systems are commercially available to utilize the fuel.

1. THE BREAK-EVEN EQUATION SOLVES FOR THE COMPETITIVE HIGH-BTU GAS COST

The break-even equation (Exhibit C-1) solves for the gas price, in dollars per million Btu, at which a high-Btu gas-fired system and the alternate system have the same life cycle cost. The analysis includes several factors:

- . Fixed Carrying Charge. In the commercial and industrial analyses, a charge for the capital employed is assessed annually, utilizing the fixed carrying rate, generated from the equation shown in Exhibit C-2, times the initial capital expense. The charge rate equation reflects

EXHIBIT C-1
Break-Even Equation

$$BE = \frac{[\$ _c + OM _c + (I _c \times f _c)] - [\$ _r + OM _r]}{I _r}$$

Where:

- c = Competing system
- r = Reference system (gas-fired)
- \$ = Fixed carrying charge (capital cost x fixed carrying charge rate)
- OM = Operation and maintenance cost per year
- I = Fuel input (million Btu/year)
- f = Fuel cost (\$/million Btu)

EXHIBIT C-2
Fixed Carrying Charge Rate Equation

$$C = \frac{1}{1-t} \left[\frac{K(1+K)^n}{(1+K)^n - 1} - \frac{t}{n} \right]$$

Where:

t = Effective income tax rate

K = Weighted average after-tax cost of capital

n = Depreciable life of the asset

the effects of sum-of-the-years depreciation and the after-tax weighed cost of capital. This puts the cost of the system on a life cycle basis. In the residential sector, capital charges are treated as loan payments over the life of the system. The interest rates, mix of debt and equity, and other assumptions used in the calculation of the carrying charge rate are shown in Exhibit C-3.

- . Operation and Maintenance Costs. This component reflects the expected annual costs associated with cleaning, inspection, repair, and normal replacement of system components. The average cost per year, over the life of the system, is treated as an annual charge.
- . Fuel Input. The fuel requirement of the system, in million Btu per year, is captured in this term. The requirement is calculated using a specified heat output rate for each application and adjusting for the system efficiency.
- . Fuel Cost. Delivered fuel costs, in dollars per million Btu at the burner tip, were derived in the work shown in Appendix B. These prices, evaluated on a regional basis, were factored into the break-even equation to give the annual fuel cost of the competing systems fired with coal, oil, or electricity where appropriate.

The break-even equation compares the annual economics of operating a coal, oil, or electric-fueled system with those of a high-Btu gas-fired system by directly solving for the price of high-Btu gas which gives an equal annual cost for the year evaluated.

Exhibit C-4 provides an example of break-even analysis. Here a 60,000-lb/hour coal boiler in Region 1 in 1985 is chosen for evaluation. With these assumptions, high-Btu gas in a gas-fired boiler would be cost competitive, on a life-cycle basis, if its cost were \$3.05/million Btu in 1978 dollars. Should the HBG cost be higher than \$3.05 in Region 1 in 1985, the coal system would be less expensive to operate, and would be the preferred system on a strict economic basis. Exhibits C-5 through C-8 show the high-Btu gas break-even prices for the chosen facilities in each of the ten Department of Energy regions. When these required prices are compared with the expected regional high-Btu gas costs, shown in Exhibits C-9 through C-12, the economically attrac-

EXHIBIT C-3
Capital Charge Assumptions

SECTOR	AVERAGE COST OF DEBT	COST OF EQUITY	CAPITALIZATION %D/%E	TAX RATE
Residential	12%	-	100%/0%	-
Commercial	6% *	16%	80%/20%	51%
Industrial	6% *	16%	50%/50%	51%

* After Tax

EXHIBIT C-4
Sample Break-Even Calculation

Competing System: 60,000 lb/hr industrial coal-fired boiler in Region 1, year = 1985,
1978 dollars

	Competing System (Coal)	Reference System (Gas)
1. Capital cost	\$3,000,000	\$1,150,000
2. Life of system	25 years	25 years
3. Tax rate	51%	51%
4. Weighted cost of capital	11%	11%
5. Capital charge rate (Exh. C-2)	.201	.201
6. Fixed carrying charge (1 x 5)	\$603,000/yr.	\$231,150/yr.
7. Operation & maintenance	\$300,000/yr.	\$115,000/yr.
8. Fuel input	579,000 MM Btu/yr.	608,000 MM Btu/yr.
9. Fuel cost	\$2.24/MMBtu	—

$$\text{Breakeven Price} = \frac{\$603,000 + \$300,000 + (579,000 \times \$2.24) - \$231,150 + \$115,000}{608,000}$$

or Breakeven Price - \$3.05/MM Btu

EXHIBIT C-5
Break-Even Prices
Residential/Commercial - 1990

APPLICATION		DOE REGION									
		New Eng.	N.Y./N.J.	Mid Atl.	So. Atl.	Midwest	So. West	Central	No.Cent.	West	No. West
Single Family Dwellings	-Electric Resistance	12.33	13.37	11.07	9.22	10.74	11.43	9.33	8.65	10.41	4.49
	-Electric Heat Pump	6.95	6.93	5.76	4.64	6.03	5.58	5.01	5.23	6.14	3.32
	-Oil Furnace	7.49	7.75	8.22	8.32	7.13	7.93	7.13	7.44	6.69	7.61
Multifamily Dwellings	-Electric Resistance	4.90	6.10	4.34	(0.40)	1.09	(2.66)	1.47	1.74	(3.83)	(0.75)
	-Electric Heat Pump	3.43	4.00	2.86	0.95	2.19	0.55	1.99	1.85	0.07	0.63
	-Oil Furnace	6.78	6.90	6.65	7.56	7.26	8.20	6.66	6.46	7.86	6.14
Office Buildings	-Hydronic Heat Pump	N/A	N/A	N/A	0.55	N/A	(4.34)	N/A	N/A	(2.88)	N/A
	-Oil Hydronic Heat	5.25	5.36	6.65	6.98	6.18	11.28	6.39	6.23	7.01	6.57
Retail Stores	-Electric Resistance	6.08	7.28	5.74	(0.45)	5.34	(14.62)	2.95	2.86	1.87	(2.38)
	-Electric Heat Pump	4.09	4.66	2.74	1.64	3.59	(0.87)	2.41	2.17	2.97	0.01
	-Oil Furnace	7.15	7.27	6.91	9.22	6.79	15.73	7.05	6.80	10.25	7.77
Schools	-Electric Heat Pump	5.20	5.77	4.00	3.85	4.57	4.94	3.96	3.43	4.98	2.16
	-Oil Furnace	6.17	6.29	6.69	7.06	5.98	8.67	6.04	6.01	8.08	6.10

Prices in \$/Million Btu, 1978 dollars.

Brackets denote negatives

EXHIBIT C-6
Break-Even Prices
Residential/Commercial - 1995

APPLICATION	DOE REGION									
	New Eng.	N.Y./N.J.	Mid Atl.	So. Atl.	Midwest	So. West	Central	No.Cent.	West	No. West
Single Family Dwellings-Electric Resistance	12.24	13.25	11.26	9.52	11.18	11.71	9.48	8.94	11.19	4.76
-Electric Heat Pump	6.90	6.87	5.84	4.78	6.25	5.69	5.08	5.37	6.14	3.44
-Oil Furnace	9.29	9.57	10.07	10.20	8.97	9.73	8.94	9.22	8.38	9.30
Multifamily Dwellings -Electric Resistance	4.81	5.99	4.53	(0.11)	1.45	(2.44)	1.58	1.98	(3.59)	(0.52)
-Electric Heat Pump	3.39	3.95	2.95	1.06	2.36	0.64	2.04	1.96	0.17	0.73
-Oil Furnace	8.28	8.40	8.17	9.09	8.77	9.73	8.17	7.94	9.24	7.53
Office Buildings -Hydronic Heat Pump	N/A	N/A	N/A	0.65	N/A	(4.27)	N/A	N/A	(2.67)	N/A
-Oil Hydronic Heat	6.63	6.74	8.05	8.39	7.58	12.69	7.78	7.59	8.29	7.85
Retail Stores -Electric Resistance	5.99	7.17	6.05	(0.15)	5.70	(14.40)	3.06	3.10	2.49	(2.15)
-Electric Heat Pump	4.05	4.61	2.86	1.75	3.76	(0.78)	2.46	2.28	3.22	0.10
-Oil Furnace	8.65	8.77	8.42	10.75	8.31	17.26	8.56	8.27	11.63	9.16
Schools -Electric Heat Pump	5.16	5.72	4.12	3.97	4.74	5.03	4.01	3.54	5.22	2.25
-Oil Furnace	7.67	7.79	8.20	8.59	7.50	10.19	7.55	7.48	9.47	7.49

Prices in \$/Million Btu, 1978 dollars.

Brackets denote negatives

EXHIBIT C-7
Break-Even Prices
Industrial - 1990

APPLICATION	DOE REGION									
	New Eng.	N.Y./N.J.	Mid Atl.	So. Atl.	Midwest	So. West	Central	No. Cent.	West	No. West
Boilers-Coal	3.05	3.11	3.12	3.00	3.02	2.69	2.55	2.65	3.31	2.73
-#6 Oil	3.96	4.12	4.27	3.86	3.96	3.90	3.94	3.77	3.78	3.82
Brick kilns-coal	3.44	3.50	3.51	3.38	3.40	3.02	2.87	2.98	3.73	3.07
-#2 Oil	4.91	5.00	5.19	5.17	4.79	4.91	4.69	4.84	4.75	4.75
Cement Kilns-Coal	2.03	2.08	2.09	1.99	2.01	1.71	1.59	1.67	2.26	1.75
-#2 Oil	4.80	4.89	5.08	5.06	4.68	4.80	4.58	4.73	4.64	4.64
Glass Furnaces-Electricity	8.33	7.09	7.42	6.28	6.84	8.05	6.06	4.56	7.46	2.44
-#2 Oil	4.81	4.90	5.09	5.07	4.69	4.81	4.59	4.74	4.65	4.65
Steel Reheat Furnaces-#6 Oil	4.27	4.44	4.59	4.17	4.27	4.21	4.25	4.07	4.08	4.13
Food Ovens-Electricity	8.26	7.06	7.38	6.28	6.81	7.98	6.07	4.61	7.42	2.56

Prices in \$/Million Btu, 1978 dollars.

EXHIBIT C-8
Break-Even Prices
Industrial - 1995

APPLICATION	DOE REGION									
	New Eng.	N.Y./N.J.	Mid Atl.	So. Atl.	Midwest	So. West	Central	No. Cent.	West	No. West
Boilers-Coal	3.18	3.20	3.22	3.08	3.08	2.77	2.64	2.60	3.37	2.83
-#6 Oil	5.22	5.42	5.57	5.16	5.28	5.21	5.24	5.01	4.70	4.76
Brick Kilns-Coal	3.59	3.61	3.64	3.47	3.47	3.12	2.96	2.92	4.09	3.18
-#2 Oil	6.67	6.77	6.99	6.97	6.57	6.69	6.44	6.60	6.18	6.18
Cement Kilns-Coal	2.15	2.17	2.18	2.06	2.06	1.78	1.67	1.63	2.53	1.84
-#2 oil	6.56	6.56	6.88	6.86	6.46	6.58	6.33	6.49	6.07	6.07
Glass Furnaces-Electricity	8.04	6.76	7.49	6.44	7.04	8.09	6.08	4.69	7.81	2.59
-#2 Oil	6.57	6.57	6.89	6.87	6.47	6.59	6.34	6.50	6.08	6.08
Steel Reheat Furnaces-#6 Oil	5.58	5.78	5.94	5.52	5.64	5.57	5.60	5.36	5.04	5.10
Food Ovens-Electricity	7.97	6.74	7.44	6.43	7.01	8.02	6.08	4.73	7.75	2.71

Prices in \$/Million Btu, 1978 dollars.

EXHIBIT C-9
Projected Delivered High-Btu Gas Price (Marginal)

Base Case - 1990
(1978 Dollars per MMBtu)

	<u>NEW ENGLAND</u>	<u>NEW YORK NEW JERSEY</u>	<u>MID- ATLANTIC</u>	<u>SOUTH ATLANTIC</u>	<u>MID- WEST</u>	<u>SOUTH- WEST</u>	<u>CENTRAL</u>	<u>NORTH CENTRAL</u>	<u>WEST</u>	<u>NORTH- WEST</u>
RESIDENTIAL	6.90	6.90	6.90	6.90	6.70	6.25	6.37	6.37	6.29	6.29
COMMERCIAL	6.44	6.44	6.44	6.44	6.46	5.81	6.20	6.20	6.29	6.29
INDUSTRIAL	6.24	6.24	6.24	6.24	6.35	5.81	6.03	6.03	6.18	6.18

EXHIBIT C-10
Projected Delivered High-Btu Gas Price (Marginal)

Base Case - 1995
(1978 Dollars per MMBtu)

	<u>NEW ENGLAND</u>	<u>NEW YORK NEW JERSEY</u>	<u>MID- ATLANTIC</u>	<u>SOUTH ATLANTIC</u>	<u>MID- WEST</u>	<u>SOUTH- WEST</u>	<u>CENTRAL</u>	<u>NORTH CENTRAL</u>	<u>WEST</u>	<u>NORTH- WEST</u>
RESIDENTIAL	6.80	6.80	6.80	6.80	6.70	6.29	6.39	6.39	6.31	6.31
COMMERCIAL	6.39	6.39	6.39	6.39	6.47	5.88	6.24	6.24	6.26	6.26
INDUSTRIAL	6.20	6.20	6.20	6.20	6.35	5.87	6.08	6.08	6.15	6.15

EXHIBIT C-11
Projected Delivered High-Btu Gas Price (15 percent rolled in)

Base Case - 1990
(1978 Dollars per MMBtu)

	<u>NEW ENGLAND</u>	<u>NEW YORK NEW JERSEY</u>	<u>MID- ATLANTIC</u>	<u>SOUTH ATLANTIC</u>	<u>MID- WEST</u>	<u>SOUTH- WEST</u>	<u>CENTRAL</u>	<u>NORTH CENTRAL</u>	<u>WEST</u>	<u>NORTH- WEST</u>
RESIDENTIAL	5.30	4.99	4.49	4.04	4.07	4.03	3.91	4.01	4.68	4.96
COMMERCIAL	4.66	4.39	4.01	3.52	3.75	3.51	3.53	3.79	4.23	4.45
INDUSTRIAL- BOILER	4.41	4.34	4.34	3.98	4.30	3.46	4.03	3.57	4.14	4.11
NON-BOILER	3.71	3.41	3.71	3.12	3.26	3.46	3.45	3.57	3.36	3.16

EXHIBIT C-12
Projected Delivered High-Btu Gas Price (15 percent rolled in)

Base Case - 1995
(1978 Dollars per MMBtu)

	<u>NEW ENGLAND</u>	<u>NEW YORK NEW JERSEY</u>	<u>MID- ATLANTIC</u>	<u>SOUTH ATLANTIC</u>	<u>MID- WEST</u>	<u>SOUTH- WEST</u>	<u>CENTRAL</u>	<u>NORTH CENTRAL</u>	<u>WEST</u>	<u>NORTH- WEST</u>
RESIDENTIAL	5.68	5.47	4.82	4.21	4.56	4.60	4.49	4.49	4.65	5.32
COMMERCIAL	5.03	4.89	4.35	3.70	4.23	4.06	4.10	4.26	4.19	4.78
INDUSTRIAL- BOILER	5.23	5.22	5.22	5.15	5.20	4.01	5.10	4.02	4.85	4.85
NON-BOILER	3.79	3.55	3.93	3.52	3.12	4.01	3.64	4.02	4.03	3.47

tive applications can be determined as shown in Exhibits C-13 through C-16. These results are the basis for the analysis and conclusions presented in Chapter II.

2. PUBLISHED SOURCES AND INDUSTRY INTERVIEWS PROVIDED
THE BASIS FOR SYSTEM AND REGIONAL ASSUMPTIONS

A variety of published sources were utilized to provide information on system assumptions for the ten Department of Energy regions. The literature consulted included:

- . Means Cost Data Manual
- . Marshall & Swift Valuation Service Manual
- . ATMES Technology Survey Data, Oak Ridge National Laboratory
- . "Replacing Oil & Natural Gas With Coal: Prospects in the Manufacturing Industries," Congressional Budget Office, August 1978
- . "Historical Statistics of the Gas Utility Industry 1966-1975," American Gas Association
- . "Oil & Gas Journal," Petroleum Publishing Co., August 13, 1979
- . U.S. Department of Air Force Engineering Weather Data
- . Several previous Booz, Allen studies.

Interviews with various manufacturers and designers of systems were conducted to update and verify the assumptions, including:

- . Various boiler, kiln, oven, and furnace manufacturers
- . American Gas Association
- . Baltimore Gas & Electric Company
- . Potomac Electric Power Company
- . Selected architecture/engineering firms.

Exhibits C-17 through C-21 indicate the building and equipment types and heating requirements assumed in this study, along with various cost estimates.

EXHIBIT C-13
Residential/Commercial Applications - 1990

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
<u>RESIDENTIAL</u>										
SINGLE FAMILY DWELLINGS:										
.ELECTRIC RESISTANCE	●	●	●	●	●	●	●	●	●	
.ELECTRIC HEAT PUMP	●	●	●	●	●	●	●	●	●	
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
<u>COMMERCIAL</u>										
MULTIFAMILY DWELLINGS:										
.ELECTRIC RESISTANCE	●	●	●							
.ELECTRIC HEAT PUMP										
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
OFFICE BUILDINGS:										
.ELECTRIC HEAT PUMP	N/A	N/A	N/A		N/A		N/A	N/A		N/A
.OIL HYDRONIC HEAT	●	●	●	●	●	●	●	●	●	●
RETAIL STORES:										
.ELECTRIC RESISTANCE	●	●	●		●					
.ELECTRIC HEAT PUMP		●								
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
SCHOOLS:										
.ELECTRIC HEAT PUMP	●	●		●	●	●	●		●	
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●

● COMPETITIVE ON MARGINAL BASIS

● COMPETITIVE IF 15% ROLLED IN

EXHIBIT C-14
Residential/Commercial Applications - 1995

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
<u>RESIDENTIAL</u> SINGLE FAMILY DWELLINGS:										
.ELECTRIC RESISTANCE	●	●	●	●	●	●	●	●	●	
.ELECTRIC HEAT PUMP	●	●	●	●	●	●	●	●	●	●
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
<u>COMMERCIAL</u> MULTIFAMILY DWELLINGS:										
.ELECTRIC RESISTANCE		●	●							
.ELECTRIC HEAT PUMP										
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
OFFICE BUILDINGS:										
.ELECTRIC HEAT PUMP	N/A	N/A	N/A		N/A		N/A	N/A		N/A
.OIL HYDRONIC HEAT	●	●	●	●	●	●	●	●	●	●
RETAIL STORES:										
.ELECTRIC RESISTANCE	●	●	●		●					
.ELECTRIC HEAT PUMP	●	●	●	●	●	●	●	●	●	●
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●
SCHOOLS:										
.ELECTRIC HEAT PUMP	●	●		●	●	●	●	●	●	●
.OIL-FORCED AIR	●	●	●	●	●	●	●	●	●	●

- COMPETITIVE ON MARGINAL BASIS
● COMPETITIVE IF 15% ROLLED IN

EXHIBIT C-15
Industrial Applications - 1990

APPLICATION	DOE REGION									
	1 New Eng.	2 NY/NJ	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
INDUSTRIAL BOILERS: .COAL .OIL						●		●		
BRICK KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
CEMENT KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
GLASS FURNACES: .ELECTRICITY .OIL	●	●	●	●	●	●	●	●	●	●
STEEL REHEAT FURNACES: .OIL	●	●	●	●	●	●	●	●	●	●
FOOD OVENS: .ELECTRICITY	●	●	●	●	●	●	●	●	●	

- COMPETITIVE ON MARGINAL BASIS
● COMPETITIVE IF 15% ROLLED IN

EXHIBIT C-16
Industrial Applications - 1995

APPLICATION	DOE REGION									
	1 New Eng.	2 N.Y./N.J.	3 Mid Atl.	4 So. Atl.	5 Midwest	6 So. West	7 Central	8 No. Cent.	9 West	10 No. West
INDUSTRIAL BOILERS: .COAL .OIL		●	●	●	●	●	●	●		
BRICK KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
CEMENT KILNS: .COAL .OIL	●	●	●	●	●	●	●	●	●	●
GLASS FURNACES: .ELECTRICITY .OIL	●	●	●	●	●	●	●	●	●	●
STEEL REHEAT FURNACES: .OIL	●	●	●	●	●	●	●	●	●	●
FOOD OVENS: .ELECTRICITY	●	●	●	●	●	●	●	●	●	

● COMPETITIVE ON MARGINAL BASIS

● COMPETITIVE IF 15% ROLLED IN

EXHIBIT C-17
Cities Chosen for System Siting

DOE REGION	CITY
1 - New England	Boston, Massachusetts
2 - New York/ New Jersey	New York, N.Y.
3 - Mid Atlantic	Washington, D.C.
4 - South Atlantic	Atlanta, Georgia
5 - Midwest	Chicago, Illinois
6 - Southwest	Dallas, Texas
7 - Central	Kansas City, Missouri
8 - North Central	Denver, Colorado
9 - West	Los Angeles, California
10 - Northwest	Portland, Oregon

EXHIBIT C-18 Residential Building Data Assumptions

Region	City	Avg. Winter °F	HDD ¹	OAT ² °F	Area Sq. ft.	Story	Infilt. ³ A. Ch/hr.	Load Btu/hr °F	Energy Req. MMBtu	Elect. Resist		Elec. Heat Pump		Oil Furnace		Gas Furnace	
										\$	Effncy.	\$	Effncy.	\$	Effncy.	\$	Effncy.
1	Boston	40.0	5634	6	1500	2	1.00	585.4	97.2	\$2240	0.95	\$2530	2.4-0.96	\$2830	0.60	\$2395	0.65
2	N.Y. City	41.1	5219	12	1500	2	1.50	644.6	85.8	2280	0.95	2570	2.4-1.22	2880	0.60	2435	0.65
3	D.C.	45.7	4224	12	1500	2	1.25	608.3	65.3	2071	0.95	2340	2.4-1.22	2711	0.60	2291	0.65
4	Atlanta	51.7	2961	17	1600	1	0.75	659.0	64.4	1960	0.95	2210	2.5-1.50	2475	0.60	2090	0.65
5	Chicago	35.8	6639	-8	1500	1	1.75	671.8	111.6	2190	0.95	2465	-	2760	0.60	2335	0.65
6	Dallas	55.3	2363	18	1700	1	0.75	599.8	48.2	1915	0.95	2155	2.5-1.51	2415	0.60	2040	0.65
7	Kansas Cty	43.9	4711	2	1500	2	1.75	705.4	92.5	2230	0.95	2510	2.4-0.96	2815	0.60	2380	0.65
8	Denver	37.6	6283	-5	1300	1	1.50	536.7	80.5	2170 ¹	0.95	2440 ¹	-	2740 ¹	0.60	2315	0.55
9	Los Angeles				1300	1	1.00		46.2	2250	0.95	2210	2.40	2415	0.60	2680	0.55
10	Portland	45.6	4635	17	1200	1	1.50	498.9	56.5	2375	0.95	2680	2.5-1.50	3000	0.60	2540	0.55

	Non Fuel O&M Cost \$/yr.	Life (Rtg. Component)
Electric Resistance Furnace	\$ 15	15 (yrs.)
Electric Heat Pump	30	10
Oil Furnace	50	13
Gas Furnace	15	15

- 1 Heating degree days
- 2 Outside air temperature
- 3 Air changes per hour

EXHIBIT C-19
Commercial Building Data Heat Output Requirements
(MMBtu/yr)

Region	City	Multifamily Dwelling	Office Building	Retail Store	School
1	Boston	403.6	1094.2	179.5	1258.5
2	New York	403.6	1094.2	179.5	1258.5
3	Washington	453.5	1046.1	226.1	925.9
4	Atlanta	240.3	826.5	81.5	634.8
5	Chicago	277.9	1173.6	205.8	1351.1
6	Houston	172.3	225.0	27.0	257.2
7	Kansas City	344.2	924.9	156.0	1064.5
8	Denver	433.6	1102.2	193.3	1269.8
9	Los Angeles	160.0	647.6	75.5	230.6
10	Seattle	425.1	807.4	110.4	925.0

EXHIBIT C-20
Commercial Building Data Assumptions

System	Efficiency	System Life (Yrs)	Capital Cost Range ^{1 2} Low - High
<u>Multifamily Dwelling</u>			
.Electric Resistance	0.95	20	\$ 56,100-\$ 64,800
.Electric Heat Pump ¹	2.00-2.40	15	64,500- 73,700
.Oil Furnace	0.60	15	71,800- 82,500
.Gas Furnace	0.65	15	68,200- 77,900
<u>Office Building</u>			
.Hydronic Source Heat Pump ¹	2.00-3.00	15	74,400- 101,700
.Oil Hydronic Heat	0.70	20	129,900- 155,400
.Gas Hydronic Heat	0.70	20	116,400- 141,200
<u>Retail Store</u>			
.Electric Resistance	0.95	20	22,500- 27,500
.Electric Heat Pump ¹	2.00-2.40	15	25,000- 31,000
.Oil Furnace	0.60	15	28,500- 34,900
.Gas Furnace	0.65	15	25,900- 32,100
<u>School</u>			
.Electric Heat Pump ¹	2.00-2.40	15	65,000- 90,800
.Oil Furnace	0.60	15	68,100- 101,500
.Gas Furnace	0.65	15	61,800- 92,000

1 Vary by region

2 New System (including coding) installed cost, 1978 dollars

EXHIBIT C-21(1)
Industrial Equipment Assumptions

Boiler:

- . 60,000 pounds of steam per hour (rated)
- . 80% load
- . 8,440 hours/year
- . Oil and gas are package units, coal constructed on site
- . 25 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ² Cost	O&M ³ Cost
Coal	486,400	0.84	579,000	\$3,000,000	\$300,000
Oil	486,400	0.83	586,000	\$1,300,000	\$125,000
Gas	486,400	0.80	608,000	\$1,150,000	\$115,000

Brick Kiln:

- . Production capacity of 100,000 bricks per day
- . Continuous operation
- . Heat input of 1000 Btu/lb. required for gas and oil; 1100 Btu/lb. for coal
- . 25 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ² Cost	O&M ³ Cost
Coal	--	--	170,600	\$1,500,000	\$50,000
Oil	--	--	155,100	1,050,000	10,000
Gas	--	--	155,100	1,000,000	--

- 1 Million Btu/Year
- 2 Installed costs, 1978 dollars
- 3 Annual charges (without fuel), 1978 dollars
- 4 Annual capital charge, 1978 dollars

EXHIBIT C-21(2)
Industrial Equipment Assumptions

Cement Kiln:

- . Capacity of 2000 tons per day
- . Operate 330 days per year
- . Dry process
- . 25 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ² Cost	O&M ³ Cost
Coal	--	--	3,366,000	\$4,250,000	\$250,000
Oil	--	--	3,960,000	3,050,000	75,000
Gas	--	--	3,960,000	3,000,000	--

Glass Furnace:

- . Flat glass
- . 500 ton per day capacity
- . Float process
- . 25 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ² Cost	O&M ³ Cost
Elec- tricity	638,800	0.95	672,400	\$4,000,000	\$10,000
Oil	638,800	0.70	912,500	5,050,000	20,000
Gas	638,800	0.70	912,500	5,000,000	5,000

- 1 Million Btu/Year
- 2 Installed cost, 1978 dollars
- 3 Annual charges (without fuel), 1978 dollars
- 4 Annual capital charge, 1978 dollars

EXHIBIT C-21(3)
Industrial Equipment Assumptions

Steel Reheat Furnace:

- . 60 tons/hr. steel throughput (rated)
- . 95% load factor
- . 8320 hours/year
- . 25 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ⁴ Charge	U&M ³ Cost
Oil	355,000	.25	1,419,000	\$2,100,000	\$1,300,000
Gas	355,000	.25	1,419,000	2,000,000	1,000,000

Food Oven:

- . 800,000 Btu/Hr (Gas), 170 KW rating (electricity)
- . 25% load factor
- . 3000 hours/year
- . 12 year life

Fuel	Heat ¹ Output	Effi- ciency	Heat ¹ Input	Capital ² Cost	O&M ³ Cost
Elec- tricity	409	0.95	430	\$40,000	Same
Gas	405	0.67	604	40,000	

- 1 Million Btu/Year
- 2 Installed costs, 1978 dollars
- 3 Annual charges (without fuel), 1978 dollars
- 4 Annual capital charge, 1978 dollars

EXHIBIT D-1
Interviews for High-Btu Gas Market Study

Institute of Gas Technology
Peoples Gas Light & Coke
Natural Gas Pipeline Company of America
Consolidated Natural Gas Company
Columbia Gas System
Illinois Commerce Commission
New York PUC
Panhandle Eastern
El Paso Corporation
Texas Eastern
California PUC
Exxon
C.F. Braun
Pullman-Kellogg
New England Congressional Caucus
American Gas Association
Chase Manhattan Bank
Salomon Brothers
Great Plains Gasification Associates

EXHIBIT E-1(1)
Potential Shifts in Energy Demand
(TBtu)

Region Sector	1990			1995		
	Gas	Oil	Elec- tricity	Gas	Oil	Elec- tricity
New England						
Residential	6	-	(6)	35	-	(35)
Commercial	1	-	(1)	5	-	(5)
Industrial	84	(84)	-	178	(178)	-
Total	91	(84)	(7)	218	(178)	(40)
New York/New Jersey						
Residential	6	-	(6)	38	-	(38)
Commercial	1	-	(1)	4	-	(4)
Industrial	54	(54)	-	160	(160)	-
Total	61	(54)	(7)	202	(160)	(42)
Mid Atlantic						
Residential	11	-	(11)	66	-	(66)
Commercial	-	-	-	3	-	(3)
Industrial	150	(150)	-	380	(380)	-
Total	161	(150)	(11)	449	(380)	(69)
South Atlantic						
Residential	30	-	(30)	183	-	(183)
Commercial	-	-	-	2	(220)	(2)
Industrial	62	(62)	-	220	-	-
Total	92	(62)	(30)	405	(220)	(185)
Midwest						
Residential	20	-	(20)	117	-	(117)
Commercial	-	-	-	3	-	(3)
Industrial	280	(280)	-	710	(710)	-
Total	300	(280)	(20)	830	(710)	(120)
Southwest						
Residential	15	-	(15)	88	-	(88)
Commercial	-	-	-	2	-	(2)
Industrial	180	(180)	-	220	(220)	-
Total	195	(180)	(15)	310	(220)	(90)

EXHIBIT E-1(2)

<u>Region Sector</u>	<u>1990</u>			<u>1995</u>		
	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>	<u>Gas</u>	<u>Oil</u>	<u>Elec- tricity</u>
Central						
Residential	7		(7)	41		(41)
Commercial	-	-	-	2	-	(2)
Industrial	4	(4)	-	30	(30)	-
Total	11	(4)	(7)	73	(30)	(43)
North Central						
Residential	4	-	(4)	23	-	(23)
Commercial	-	-	-	-	-	-
Industrial	10	(10)	-	20	(20)	-
Total	14	(10)	(4)	43	(20)	(23)
West						
Residential	15	-	(15)	90	-	(90)
Commercial	-	-	-	1	-	(1)
Industrial	116	(116)	-	177	(177)	-
Total	131	(116)	(15)	268	(177)	(91)
Northwest						
Residential	-	-	-	-	-	-
Commercial	-	-	-	-	-	-
Industrial	18	(18)	-	40	(40)	-
Total	18	(18)	-	40	(40)	-

Note: Brackets denote negatives

EXHIBIT E-2
Projected Sources of Gas Supply in 1990 and 1995 (TBtu)

<u>Year/Source</u>	<u>New England</u>	<u>New York New Jersey</u>	<u>Mid Atlantic</u>	<u>South Atlantic</u>	<u>Midwest</u>	<u>Southwest</u>	<u>Central</u>	<u>North Central</u>	<u>West</u>	<u>Northwest</u>	<u>Total</u>
<u>1990</u>											
Domestic Conventional ²	411	660	1060	1668	2134	4720	928	605	811	112	13,109
Alaska	14	46	61	100	282	55	46	9	245	18	876
Canada	40	5	--	--	367	--	--	52	449	187	1,100
LNG	23	74	127	110	242	4	14	--	309	--	903
Mexico	5	15	26	22	49	1	2	--	63	--	183
Synthetic Gas ¹	<u>17</u>	<u>70</u>	<u>36</u>	<u>--</u>	<u>136</u>	<u>--</u>	<u>--</u>	<u>34</u>	<u>3</u>	<u>83</u>	<u>379</u>
Total	510	870	1310	1900	3210	4780	990	700	1880	400	16,550
Shifted Demand	601	931	1471	1992	3510	4975	1001	714	2011	418	
Maximum Address- able Market	91	61	161	92	300	195	11	14	131	18	
<u>1995</u>											
Domestic Conventional ²	321	618	1030	1628	1820	5049	900	590	802	126	12,884
Alaska	14	46	61	100	282	55	46	9	245	18	876
Canada	40	5	--	--	367	--	--	52	449	187	1,100
LNG	23	74	127	110	242	4	14	--	309	--	903
Mexico	5	15	26	22	49	1	2	--	63	00	183
Synthetic Gas ¹	<u>57</u>	<u>82</u>	<u>36</u>	<u>--</u>	<u>300</u>	<u>111</u>	<u>18</u>	<u>79</u>	<u>82</u>	<u>79</u>	<u>844</u>
Total	460	840	1280	1860	3060	5220	980	730	1950	410	16,790
Shifted Demand	678	1042	1729	2265	3890	5530	1053	773	2218	450	
Maximum Address- able Market	218	202	449	405	830	310	73	43	268	40	

¹ Includes SNG from naptha and medium-Btu gas; does not include high-Btu gas.

² Note that gas used as raw material, feedstock, refinery or electric utility fuel is excluded. Thus, total U.S. demand is reduced by some 3,000 TBtu, all of which it is assumed would have been supplied through domestic conventional sources.