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**Pacific Northwest Energy Related
Regional Assessment Program**

**The Potential for Producing
and Marketing Gasoline
Substitutes from Western Coal**

September 1976

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THE POTENTIAL FOR PRODUCING AND MARKETING
GASOLINE SUBSTITUTES FROM WESTERN COAL

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September 1976

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EXECUTIVE SUMMARY

This study, part of the ERDA-sponsored Pacific Northwest Laboratories Regional Assessment Program was undertaken to assess the potential for producing and marketing gasoline substitutes from western coal. A similar study was done for the Battelle Energy Program; results of that study are incorporated into the discussions and conclusions presented here.⁽¹⁾ A partial analysis framework was used to treat the domestic supply and demand for gasoline, the supply of gasoline substitutes from western coal and the level of petroleum imports (a policy variable). The major results and conclusions of the study are:

1. With present technology and prices, gasoline from coal can be produced and distributed more cheaply than methanol. However, the costs of producing and distributing synthetic gasoline under current (1975) prices and technology are 50 to 100% higher than petroleum-based gasoline. It is doubtful that with existing technology this cost advantage will change during the next 25 years.
2. Obviously, considerable uncertainty exists relative to the future prices of gasoline and coal. Synthetic gasoline could have a cost advantage in the near term, but changes in import policy and/or prices could place synthetics at a competitive disadvantage after liquefaction units come on line (8 to 10 years). Because of the industry's relatively large capital requirements, this uncertainty probably precludes full-scale production efforts of synthetic gasoline without a) a federally guaranteed pricing structure or b) a policy to severely restrict and/or tax imports.

These are tentative conclusions, based solely on the cost advantages and relative price movements projected by this study. No potential long-term balance of payment and capital formation problems nor federal policies other than petroleum import policies were considered. Assessing the potential for future improvements in synfuels technology and the resulting

impacts was not an objective of this study. However, theory and applicable methodology are available for treating this issue as outlined in the section on future research possibilities.

The results of this study will influence the Regional Assessment Program in the following ways:

1. The assessment of impacts resulting from other commercial scale coal-related activities (strip mining, electric power generation and gasification) will receive initial priority over those resulting from the production of synthetic gasoline.
2. The production and cost relationships derived in this study will be input to a large-scale model being assembled by PNL for assessment of mid and long term regional effects expected to result from changing energy production and consumption patterns.

1. INTRODUCTION

Though petroleum supplies appear threatened, the United States has large reserves of coal. This resource could become a partial substitute for petroleum within various sectors of the economy. The greatest percentage (over 40%) of petroleum in this country is used as gasoline for transportation.⁽²⁾ Using available technology to produce synthetic fuels from coal, mass-produced substitutes for petroleum-based gasoline could be introduced within the 8 to 10 years lead time needed for full-scale plant production.

This study, part of the ERDA-sponsored Pacific Northwest Laboratories Regional Assessment Program was undertaken to assess the potential for producing and marketing gasoline substitutes from western coal.^(a) Through June, 1978, one major emphasis of the program is a regional coal assessment for input to the ERDA National Coal Assessment (NCA). The NCA will utilize information on regional energy options to 1) generate development scenarios and to 2) evaluate regional impacts associated with these scenarios.

One problem that the NCA must face is determining the likelihood of a particular development occurring within the region. An adequate assessment does not merely ask "what if" questions and then analyze the impacts of the "what ifs"; the probability for the "what ifs" to occur must also be addressed. Ideally, some estimate of an expected value of a particular energy option or development scenario is desired. This expected value should equal the probability of occurrence of a particular development scenario multiplied by the values attributed to the impacts.

Before embarking on a large-scale program to assess the socioeconomic, environmental and health effects of placing several coal liquefaction

(a) The purpose of the program is to assess (using secondary data and existing techniques) the environmental, socioeconomic and health effects of future energy options for the states of Alaska, Idaho, Montana, Oregon, Washington and Wyoming.

plants in the western United States, it was essential to have some indication of "if" and "when" state-of-the-art and future technologies might be utilized. This information could be used to prioritize (in terms of likelihood of future occurrence) the regional energy options and specific technologies for which the impacts are to be assessed.

A multisector model with regional detail would be required to thoroughly assess the likelihood of commercial scale liquefaction occurring in Montana and Wyoming under market conditions. However, significant information can be obtained from a constrained partial analysis, which was the procedure for this study.

Some fundamental terminology used in this analysis is reviewed in Section 2 of this report. Future demand and potential supply of gasoline from domestic crude oil are treated in Sections 3 and 4. The costs of supplying synthetic gasoline and methanol from western coal as well as the qualitative aspects of these fuels are examined in Section 5. In Section 6 the supply and demand functions are solved simultaneously under various import schemes to trace out a family of gasoline-market equilibrium price curves over time. Three scenarios are then analyzed by comparing the costs of supplying synthetic fuels with the market equilibrium prices for gasoline. Market potential for the synthetic fuels is estimated for a wide range of coal prices. Section 7 includes a summary, concluding comments, and research recommendations.

2. EVALUATION METHODOLOGY

Much of the current literature on the energy problem contains diagrams similar to Figure 1, where an energy "gap" or "shortage" for the nation develops with time. The "demand", Curve A, increases at a greater rate than the "supply", Curve B. This implies that additional production of energy, in this case gasoline or gasoline substitutes, "must" be undertaken to alleviate the gap between supply and demand. However, such an implication fails to completely assess the meaning of supply and demand and the interrelationship of these two concepts.

FIGURE 1. Projected Gasoline "Shortage"

The static demand function for a commodity may be expressed as the following vector:

$$D_t = f(p_{t_d}, Y_t, X_{1,t}, \dots, X_{n,t}) \quad (1)$$

where

t = time period in question

P_{t_d} = price that consumers are willing to pay for the commodity in time t

Y_t = real income level in time t

$X_{1,t} \cdots X_{n,t}$ = an array of other relevant parameters.

Likewise, the supply function for a commodity may be generalized on t as

$$S_t = g(P_{t_s}, Z_{1,t} \cdots Z_{m,t}) \quad (2)$$

where

P_{t_s} = price at which producers are willing to supply the commodity in time t

$Z_{1,t} \cdots Z_{m,t}$ = an array of other relevant parameters and functions usually including industry costs and production relationships.

This classical relationship of supply and demand for any time t with all other variables constant is shown in Figure 2. The figure shows that supply and demand are price-quantity relationships. Solving equations (1) and (2) simultaneously yields the market equilibrium price, P_e , and quantity, Q_e for time t . If the price were below P_e (say at P_1), the amount demanded, Q_D , would exceed the amount producers would be willing to supply at that price, Q_S . Recognizing this impending shortage by increased sales from inventories, the suppliers would raise their asking price until it reached P_e while increasing production from Q_S to Q_e . Thus, 1) shortages (surpluses) are defined by an excess of demand (supply) over supply (demand) at a particular price, and 2) supply and demand are price-quantity relationships. The possibility of long-run shortages of a commodity (gasoline) is extremely remote unless that commodity is rationed by something other than market prices. Prices ration available output and induce output adjustments.

FIGURE 2. Price-Quantity Relationship Between Supply and Demand

This conclusion appears at odds with the popular usage of Figure 1. To describe how the supply-demand relationships of Figure 2 fit into the framework of Figure 1, it is necessary to develop the argument one step further.

As per capita incomes and population increase and relative prices and preferences change over time, the demand function for a commodity would be expected to shift to the right (Figure 3). Likewise, favorable changes in production and cost structures due to technological change or lower input prices may shift the industry supply function to the right. The line K-K' in Figure 3 represents the intersections of the shifting supply and demand functions, i.e., the locus of equilibrium price-quantity combinations over time. If the line K-K' is projected into quantity-time space, the result is representative of the line labeled "supply" (Curve B) in Figure 1.^(a) Although this is the actual quantity supplied over time, Curve B also represents the actual quantity demanded.

(a) The slope of K-K' is unrelated to the slope of Curve B in Figure 1. However, a necessary and sufficient condition for Curve B to retain a positive slope is that the market equilibrium quantity be increasing.

FIGURE 3. Shifting Supply and Demand over Time

Because the "supply" curve in Figure 1 is a locus of points representing the equilibrium quantity supplied and demanded over time, there are no long-run shortages. The "demand" curve and "shortage" in Figure 1 have little meaning within an economic framework unless the commodity in question (gasoline) is rationed by means or devices other than market prices. What then does the "demand" curve of Figure 1 really mean? It represents projected consumption or the "requirements" needed to meet a particular set of objectives. An example would be the gasoline which would be consumed if vehicles per capita were to increase at a specified rate over time. Although this "requirements curve" will not be used in the analysis of equilibrium market conditions, it is addressed later in Section 6, the development of scenarios.

3. DEMAND FOR GASOLINE

The demand for gasoline is a derived demand; i.e., the final consumption process is composed of factors derived from the combustion of gasoline through fixed capital stock (automobiles) within a given time period. These factors usually take the form of miles traveled, power delivered, and/or other variables. Thus, because the demand for gasoline is not only a function of prices and incomes but of the existing capital stock as well, theory suggests that model specifications take account of this.

A search of the literature revealed two basic approaches to the econometric modeling of gasoline demand, both explicitly accounting for the stock of automobiles. One approach, based upon distributive lag models, utilizes time series or pooled time series/cross-sectional data in a log-linear dynamic stock or flow adjustment framework with lagged variables.⁽³⁾ The other more traditional approach uses cross-sectional data in a static framework.

Econometric models of gasoline demand using only cross-sectional data yield long-run elasticities while the distributive lag models tend to capture both short and long-run effects of price changes. The short-run demand; i.e., the effects between successive time periods, is invariably shown to be price inelastic^(a) because the consumer is "locked in" to his existing capital stock. If gasoline prices are rising and the consumer expects a continued upward trend, he may adjust his capital stock in the future. For example, when he decides to trade automobiles, he may choose to acquire a smaller, more efficient vehicle. The consumer would now be in a long-run situation and his consumption of gasoline would be less with

(a) Price elasticity is defined as the relative change in quantity divided by the relative change in price; i.e., dQ/Q divided by dP/P . For a normal commodity the absolute value of the price elasticity may range from ∞ to zero. If the elasticity has an absolute value less than 1.0, it is termed "inelastic". If the absolute value is greater than 1.0, it is "elastic". Thus, if the short-run demand for gasoline were price inelastic, a 1% increase in price would result in less than a 1% reduction in gasoline consumption.

the more efficient vehicle, other things being equal. Thus, while the consumer's demand for gasoline may still be price inelastic, the value of the elasticity becomes a larger absolute number (by as much as a factor of 10) than the short-run elasticity.

Although the distributive lag models appear to be reliable predictors, none was found which effectively incorporated other than United States data into the model. This is important because if domestic gasoline prices are expected to move to new highs, the reliability of predictions from these models outside the range of historical data is questionable. For years the Europeans have faced relatively high gasoline prices (Figure 4) as well as real per capita incomes considerably below those in the United States. The ways in which the Europeans have adjusted gasoline consumption and automobile stocks over time may indicate future American trends. A model developed by Adams, et al., utilizes cross-sectional data from 20 Organization for Economic Co-Operation and Development (OECD) countries including the United States; thus, gasoline price data with a range greater than prices experienced in the United States were available.⁽⁴⁾ The data apply to the year 1969, which was chosen because it was the most recent full year before petroleum price increases deviated sharply from past trends.

Several model specifications were investigated by Adams, et al., for gasoline demand and for interrelationships and dependencies among the independent variables of the demand functions. These analyses led to rejection of gasoline cost as an important determinant of the number of cars per capita. It was found that gasoline price first affects the use of cars and then car size, not the number of cars. Based on their conclusions and suggestions, the following log-linear model was chosen as representative of the long-run demand for automotive gasoline in the United States⁽⁵⁾ (t-statistics in parentheses below coefficient):

FIGURE 4. Gasoline Prices and Excise Taxes Around the World
Source: Richardson Associates, New York

$$\ln Q_t = 4.0092 - 0.8627 \ln P_t + 0.4080 \ln \text{GDPPC}_t - 0.5607 \ln \text{CARPC}_t + 0.6588 \ln \text{CMAS}_t + 0.2029 \ln \text{HPP1b}_t \quad (3)$$

(1.332) (4.045) (3.3049)
 (7.8024) (2.1155) (0.8693)

Multiple correlation coefficient (R^2) = 0.9327
 Standard error of the estimate (s.e.) = 0.122

where

- Q = gasoline consumption (thousands of metric tons per million cars per year)
- P = price of gasoline (cents per liter)
- GDPPC = gross domestic product (thousands of dollars per capita)
- CARPC = cars per capita
- CMAS = weight of average U.S. car (pounds)
- HPPIb = average horsepower per pound
- t = time period of interest.

The log-linear models are frequently used because they possess two appealing characteristics. First, theory suggests the existence of curvilinear functions⁽⁶⁾ and the log-linear functions have traditionally provided excellent data fits.^(a) Secondly, the log-linear models exhibit constant elasticities which are represented by the numerical coefficients. Because equation (3) was estimated from cross-sectional data, the coefficients represent long-run elasticities.

(a) 1973 U.S. data applied to equation (3) yield less than a 1.00% error.

4. SUPPLY OF GASOLINE

The framework and functional relationships to be used in estimating gasoline demand were outlined in the last section. This section projects the domestic supply of gasoline. These projections will then be combined with estimates of the independent variables in equation (3) to generate market equilibrium prices over time.

UNITED STATES CRUDE OIL PRODUCTION (1970-2000)

Estimating future domestic gasoline supply requires estimating future domestic crude production and the refined product mix. This, in turn, requires estimating the future crude reserve discovery rate; at best, a very difficult and speculative process.^(7, pp. 1-76) Another difficulty is that oil and gas discoveries and long-run production occur as joint products, which requires a disaggregation of total costs to the respective fuels.^(8,9) Although cost and supply functions have been estimated, these estimations include only the conterminous United States and the relationships should be used cautiously for long-term forecasting.⁽⁷⁻⁹⁾ Because of this, the future availability of domestic crude oil (including Alaska and offshore projections) will be estimated from recent geological and engineering data.

Oil occurs only in limited space in underground porous sedimentary rocks, at depths ranging from a few hundred feet to five or more miles. Therefore, it is difficult to find with any degree of certainty. Two methods have evolved which have traditionally been used for estimating the crude oil reserves of the United States. The first method involves estimating the total land area underlain by sedimentary rock, the amount of footage drilled per square mile of sedimentary rock, and the number of barrels of crude obtained per foot drilled. The second method is based on cumulative information and evidence resulting from the total amount of exploration and production activities in the United States.

Using the first method and assuming one well per two square miles of drillable land and a constant of 118 barrels per drilled foot, A. D. Zapp⁽¹⁰⁾ postulated in 1961 that the ultimate total producible amount of crude oil in the United States was 590 billion barrels (10^9 bbl). Not only was this the basis for Zapp's estimate but with only minor modifications it has been the principal basis for most of the recent estimates by the National Petroleum Council, the United States Geological Survey, and the American Petroleum Institute.^(11,12) A major problem with Zapp's hypothesis is his assumption that the number of barrels yielded per foot of drilling is a constant. This has been shown to be false. In fact, the number of barrels per foot drilled has been decreasing exponentially from a high in 1930 of 275 barrels per foot to 35 barrels per foot in 1965.⁽¹³⁾ By using this information and ignoring the Zapp hypothesis, integration (summing) over the range of estimated cumulative footage drilled suggests about 165×10^9 bbl as a total producible amount of domestic (excluding Alaska) crude oil.

The second method of estimation uses the "Hewett Criterion",⁽¹⁴⁾ which states that the complete history of exploration and production of any nonrenewable resource must go through stages from infancy to maturity to old age. Maturity is the stage of production "peaking" and old age is the advanced state of discovery and production decline. This criterion has been investigated by M. King Hubbert^(13, 15-18) several times since 1956. From his investigations and communications with experienced petroleum geologists and engineers he concluded that the ultimate amount of crude to be produced from the conterminous 48 states and adjacent continental shelves would probably be in the range of 150 to 200×10^9 bbl. Using this ultimate production range and data provided by the petroleum industry, Hubbert fit a logistics curve to the production curve of the 48 states to predict future production rates of crude oil for the United States.

In addition to the above estimates, other estimates of the total amount of recoverable oil in the United States have been made by Mobil Oil Company, the United States Geological Survey (USGS), and the National Petroleum Council (NPC). These three estimates, as well as a modified

version of Hubbert's predictions,^(a) for both the lower 48 states and Alaska are shown in Table 1.

TABLE 1. Estimates⁽¹¹⁾ of Total Recoverable Crude Oil in the United States (10^9 bbl)

	<u>Modified Hubbert</u>	<u>Mobil Oil Co.</u>	<u>USGS</u>	<u>NPC</u>
Lower 48	54	72	170	105
Lower 48 plus Alaska	94	123	235	150

Figure 5, constructed in part from Table 2, shows estimates of crude oil production rates for the United States from 1970 to the year 2000. Curve A is the NPC projection for the production rate in the lower 48 states, while Curve B is Curve A plus the NPC estimated rate for Alaska.⁽¹⁹⁾ Curve C also gives the production rates of crude oil in the lower 48 states relative to time. This curve was obtained by modifying Hubbert's logistic curve to fit recent data provided by the petroleum industry. Curve D is the projected total production rate of the United States (lower 48 states plus Alaska) and was obtained by adding Curve C to the NPC projection for Alaska. Curve D is assumed to represent domestic crude oil production for this study.^(b)

(a) The time constant to Hubbert's equation has been slightly increased while holding the peak production constant.

(b) Our estimates of crude oil supply are among the lowest available, and are similar to the Project Independence business-as-usual projection at \$4/bbl.^(2; p. 91) We realize that using the conservative supply estimates may bias our results in favor of liquefaction.

FIGURE 5. Projected Domestic Production of Crude Oil

TABLE 2. Estimated⁽¹¹⁾ Crude Oil Production to the Year 2000 (10^6 bbl/day)

Year	Lower 48- (NPC)	Lower 48 (Modified Hubbert)	Total U.S. (NPC)	Total U.S. (Modified Hubbert Plus NPC Alaska)
1970	9.10	9.05	9.10	9.05
1975	8.55	9.10	9.15	9.10
1980	8.13	8.70	10.10	10.70
1985	7.90	7.94	9.87	9.94
1990	—	6.92	—	9.42
1995	—	5.81	—	8.81
2000	—	4.73	—	7.73

By summing the areas under Curves A and B in Figure 5, the cumulative production estimates by the NPC for the United States excluding and including Alaska are 46.0 and 52.4×10^9 bbl, respectively, for 1970 to 1985. The area under Curves C and D predicts the total production as 53.6 and 59.1×10^9 bbl for the same period of time and 88.4 and 108.4×10^9 bbl for the years 1970 to 2000. The total cumulative domestic production for the United States oil industry to the year 1970 was 89.5×10^9 bbl.

GASOLINE PRODUCTION FROM DOMESTIC CRUDE OIL (1975-2000)

Estimating the amount of gasoline that will be produced from domestic crude oil requires knowledge of 1) the types and amounts of petroleum product imports, 2) the refinery production mix that is technically possible, 3) costs of all refinery inputs, and 4) wholesale produce prices and taxes.

Because time limitations prevented an in-depth analysis of the above, future conversion rates of crude oil to gasoline were estimated on the basis of existing conversion rates. The historical average yield to gasoline from a barrel of crude has been estimated at 44.3%.^(20, p. 242) The average yield for 1974 was around 46%;^(21,22) the conversion rate for 1972-1974 was 53%.⁽²³⁾ Because the mix of petroleum inputs used to produce gasoline involves not only crude oil, but natural gas liquids, over one-half barrel of gasoline is produced for every barrel of crude input to the refining process.

Gasoline is being imported at a rate of about 2 to 4% of domestic gasoline production.⁽²³⁾ Thus, assuming no changes in the production and import mix, the conversion rate of crude oil to gasoline is chosen as 55%. This rate accounts for the gasoline produced per barrel of crude input to refineries plus the small percentage of imports. Table 3 shows the projected supplies of gasoline resulting from domestic crude at a 55% conversion rate.

TABLE 3. Projected Supplies of Gasoline Available From Domestic Crude for 55% Conversion Rates (10^6 bbl/day)

<u>Year</u>	<u>Modified Hubbert Plus NPC Alaska</u>
1975	5.01
1980	5.89
1985	5.47
1990	5.18
1995	4.85
2000	4.25

Price has not been mentioned in the projections of gasoline supply from domestic crude because the literature reviewed does not explicitly account for price; the projections were made on a judgmental basis. However, by assuming that in the future the domestic crude oil from Alaska will be highest in cost, estimating the cost of producing and distributing gasoline from Alaskan crude would project the supply price at the margin. As long as the market price is at or above this level, the minimum amount of gasoline produced from domestic crude would be represented by the projections in Table 3.

Cicchetti⁽²⁴⁾ has estimated the cost of transporting North Slope crude to Los Angeles under a number of scenarios. His most liberal estimate is \$1.26 (1971 dollars) per barrel. The total cost of North Slope crude delivered to Los Angeles may be estimated by adding to the transportation cost 25% for the average wellhead price,^(12,20) doubling this to cover royalties and underestimated costs, and inflating to 1973 dollars. The final cost is \$3.19/bbl. Assuming two barrels of petroleum yield a barrel of gasoline, one-half the cost of transporting a barrel of crude oil to Los Angeles from Alaska is assumed to be allocated to gasoline. Using this information and data on refining and distribution costs, Table 4 estimates the average cost (1973 dollars) of gasoline at the pump (excluding taxes) to be 27.7¢/gal. Table 5 indicates that this estimate is slightly above the average 1973 price and far below the 1974 prices. Therefore, it is

assumed that the estimated gasoline supplies from Table 3 will be marketable at or below 1974 pump prices.

TABLE 4. Estimated Average Supply Price of Gasoline
(ex. tax) from Alaskan Crude (\$/bbl - 1973)

Crude Delivered to Los Angeles	3.19
Refining Costs ^(20,25)	3.20
Transportation and Distribution	5.25
Total	\$11.64/bbl or 27.7¢/gal

TABLE 5. Comparison of Estimated Supply Price of Gasoline
(ex. tax) from Alaskan Crude with Average Gasoline
U.S. Prices (\$ 1973)

<u>Estimated Alaskan</u>	<u>1973 U.S. Average</u>	<u>1974^(a) U.S. Average</u>
27.7¢/gal	27.0¢/gal	35.9¢/gal

Source: Table 4 and Reference 22.

(a) Assume 11% deflator (CPI) to 1973 dollars - Survey of Current Business,
U.S. Dept. of Commerce, p. S8, April 1975.

Projections of the future supply of domestic crude oil and gasoline were presented in this section. The following section investigates the future supplies of coal and synthetic fuels produced from coal, and compares the estimated costs of these fuels to the current price of gasoline.

5. PORTABLE FUELS FROM COAL

Estimates of the coal reserves in the conterminous United States range as high as 4.34×10^{12} tons, of which about half or 2.1×10^{12} tons are considered recoverable. (2, p.19) Recent evidence suggests that the coal reserves of Alaska may surpass even those of the lower 48 states. (26) At present rates of consumption (55×10^6 tons/yr) our national coal reserves would last nearly 4000 years. (2, p.20) Western coal is non-caking, which is particularly suited for current synthetic fuel processes. (27, p.34) This feature with the vast and accessible reserves located in Montana and Wyoming is causing serious consideration of producing synthetic fuels from coal in this region.

In the western coal region, a total of 1.5×10^{12} tons of known, assumed and hypothetical coal are located in the 63-county Northern Great Plains (NGP) area (Montana, Wyoming and North Dakota); this is roughly 50% of the national reserve. Of this total, 1.6×10^{11} tons of coal are known to be less than 1000 ft below the surface, with about half of this amount surface minable. This figure represents 37% of the total national minable coal (by weight) and 60% of the surface-minable national reserve. (28) For Montana and Wyoming, estimates have been made of 2.3×10^{11} total economically recoverable tons. Roughly half of this amount exists in each state. (29)

Because the coal is located near the surface in relatively thick seams, a high yield is obtained per acre of land. Large-scale operations are possible, decreasing the cost of the coal produced. The high yield of coal per acre and the relatively flat terrain mean that immediate reclamation costs are less. (However, revegetation in the arid and semi-arid west is more costly. Irrigating and manually planting native vegetation are necessary to replace the ground cover.)

Predictions of the number of synthesis/conversion plants expected to be located in the west over the next 30 years vary. As many as 20 gasification plants are predicted to be located in Montana by 2000. (30, p. 133)

By 2010, these plants would contribute to an estimated national production of 2.5×10^7 bbl/day of liquid and gaseous synthetic fuel. This would require 3.5×10^9 tons of coal per year, ^(2, p.432) over 6 times the current national production. Such consumption could even rapidly deplete national coal resources. Project Independence projects, however, that even with conservation of oil and a major shift to electric power, by 2010 at least 8×10^6 bbl/day of synthetics will be required to meet the projected base case demand. ^(2, p. 432)

Another estimate predicts 10 to 15 liquid fuel plants in Montana by 2000. ^(30, p. 133) A third estimate predicts 38 plants (20 methane, 8 methanol and 10 liquefaction), utilizing western coal, to be operational by 1985-1990. These plants would produce 1.4×10^6 bbl/day of syncrude, methanol, and high-Btu methane gas, and consume 2.6×10^8 tons of coal per year. ^(27, p. 47)

Other factors, however, indicate that portable fuels produced by coal liquefaction and/or gasification are not dependable sources of alternate transport fuel. Liquefaction results from either of two processes; direct catalytic hydrogenation, or gasification followed by catalytic synthesis to liquid fuel. Germany used hydrogenation to produce as much as 90% of her peak aviation and motor fuel demand during WWII, and a small (9000 bbl/day) gas synthesis plant now operates in South Africa. ⁽³¹⁾ However, both liquefaction processes are relatively inefficient and therefore, expensive (though hydrogenation is potentially the more efficient of the two ^(31, p. 9)). History suggests that one way liquefaction can become an important source of transport fuel is through improved technology. These improvements could include better reactor designs for contacting the coal and hydrogen over a catalyst, less expensive and more durable catalysts, liquefaction schemes occurring at lower temperatures and pressures, low cost methods of producing process hydrogen, and determining the kinetics and mechanisms by which liquefaction proceeds. ^(31, pp. 6-9)

In addition to the required technological improvements, other factors limit the expansion of the coal industry. These factors include the lead time required to produce capital equipment for strip mines, the capital to

invest in such equipment and to build conversion plants, the increased manpower required to mine the coal and build and operate the conversion facilities, and the impact of this influx of resources on the sparsely-populated states of the NGP.

The amount of coal produced in the west has never been proportional to the reserves. For example, 1975 production was only 5.5% of the national total. (28, p. 17) Reasons for this are 1) the low Btu content (8,000-12,000 Btu/lb) of western coal relative to eastern coal (17,000-25,000 Btu/lb) and 2) the relatively high cost of shipping western coal to heavy coal-using industrial areas of the east. For example, the costs of shipping coal to the midwest can amount to two-thirds of the delivered price. Another obstacle to industry expansion is that ownership of coal is unclear; one party may claim rights to the coal itself while another party may own the land over the coal.

FUEL CHARACTERISTICS IN THE INTERNAL COMBUSTION ENGINE

Three types of fuels and combinations of fuels have received the majority of attention in the literature as potential substitutes for petroleum-based gasoline. These are methanol, gasoline, and a methanol-gasoline blend. Because essentially no data are available on the use of these coal-derived fuels in spark ignition engines, it becomes necessary to infer performance characteristics from limited data on physical and chemical properties. Although a general approach, this does identify areas where additional data are needed to adequately evaluate the fuels.

Methanol

The use of pure methanol as a fuel in the internal combustion engine will require consideration, as well as solution, of several potential problems. Some drawbacks and advantages of methanol as a fuel are:

- 1) The relatively low volatility of methanol (149°F boiling point) would require a special means of starting carburetor-equipped engines at low temperatures. (25, Vol. II, p. 115)

- 2) The high heat of vaporization would require special heated manifolds for providing suitable air-fuel mixtures for ignition. (32, V. II, p. 141)
- 3) The low heat of combustion would require a large fuel system to give satisfactory range and performance. (32, V. II, p. 141)
- 4) The high octane number of methanol (106 research and 92 motor octane unleaded) would be expected to permit operation at increased compression ratios, improving efficiency. (25, V. II, p. 175)
- 5) The result of burning methanol in internal combustion engines is predicted to be reduced emissions (unburned hydrocarbons, carbon monoxide and nitrous oxide) over conventional gasoline. (33)
- 6) The effects of methanol on materials used to build the fuel system have not been fully evaluated.

With the above modifications, the internal combustion engine would be essentially inoperable with conventional gasoline. Therefore, an additional fuel distribution system would be required to use gasoline and methanol separately.

Methanol-Gasoline Blend

The methanol-gasoline blend appears to have some advantages over a pure methanol fuel, but several significant problems remain. At low temperatures the miscibility of the blend decreases rapidly; a phase separation results causing decreased engine performance. This problem is greatly intensified if water is present. The presence of even 0.5% water will cause almost complete phase separation at 76°F. (25, Vol. II, p. 32) At lower temperatures the problem becomes even more severe. If such a blend were marketed, the blending probably would occur at the pump. It appears doubtful that a distribution system could be kept totally dry from the refinery to the customer's gas tank. Further, the problem of phase separation in the gas tank as the methanol absorbs water from the air would still need to be solved. Although this problem might eventually be overcome by the use of additives, little information is currently available on the subject. (32, Vol. II, p. 231)

Methanol-gasoline blends are also quite volatile and exhibit high vapor pressures even with relatively small amounts of methanol. For example,

a blend having as little as 2% methanol could cause significant vapor lock problems in standard engines due to increases of around 3 psig in vapor pressure.^(25, Vol. II, p. 179) Modifications of existing automotive fuel systems would be required to efficiently utilize a methanol-gasoline blend.

Various methanol-gasoline blends have been tested in unmodified internal combustion engines in a research environment.⁽³³⁾ The problem of vapor lock was not considered and, although the results were impressive (increased acceleration and fuel economy and decreased exhaust temperature and emissions), the significant problems mentioned above must still be overcome. While the technical solutions to the problems are no doubt available, the cost of implementing these may make the methanol-gasoline blends prohibitively expensive.

Gasoline

Unlike pure methanol and methanol-gasoline blends, gasoline produced from synthetic crude oil (syncrude) would appear to create very few problems when used in existing internal combustion engines. Problems that might occur would probably result from the high aromaticity (large amounts of benzene) of synthetic gasoline which could cause difficulty in starting at low temperatures and possible deterioration of some of the fuel system components. These problems could probably be solved by carburetor and material modifications, or by mixing with petroleum-based gasoline.

Market Acceptance of "New" Fuels

If methanol were to enter the portable fuel market, it would probably be as a blend with gasoline. The all-methanol automobile could be slowly introduced as a replacement for gasoline-powered vehicles.

The public, of course, would have little trouble accepting coal-derived gasoline. It would be mixed with petroleum-based gasoline and, with no loss of performance, would likely be treated by consumers as a perfect substitute for petroleum gasoline.

PRIVATE COSTS OF SUPPLYING SYNTHETIC FUELS^(a)

Both production and distribution costs are involved in the supply costs of synthetic fuels. No full-scale plants now operate in the United States; therefore, production costs have been estimated by engineers evaluating the production potential of these fuels. Reliable estimates of distribution costs are available from the present costs of distributing gasoline.

Several studies have estimated the costs of producing synthetic fuels from coal. All of the studies reviewed used different prices and heating values for the coal. Therefore, the data from these studies have been transformed to a common basis and compared for 8500 Btu/lb coal at 65¢/10⁶ Btu (\$11/ton) in 1973 dollars. The heating value of 8500 Btu/lb was chosen because 1) this is the mean value used by Kant, et al., (25, Vol.II,p.124) for detailed cost estimation of the proposed El Paso syncrude facility and 2) it is a reasonable estimate of the average Btu content of Montana and Wyoming coal. The price of 65¢/10⁶ Btu was chosen from an Institute of Gas Technology (IGT) study headed by Pangborn and Gillis⁽³²⁾ because of their detailed treatment of future coal prices. The predictions of Pangborn and Gillis were cost-based; i.e., made by addressing the supply side of the market. Their argument was one of increasing marginal costs for opening and operating new mines for producing synthetic fuels.

The results of the cost estimations for producing and distributing methanol and synthetic gasoline are shown in Table 6. Petroleum gasoline prices for 1973 and 1974 are also shown for a base reference. It is assumed that refineries would be located at mine-mouths to avoid the relatively high transportation costs of coal. The studies recently completed at Exxon⁽²⁵⁾ and IGT⁽³²⁾ were intensive, in-depth analyses of available technology; whereas, the study at the Massachusetts Institute of Technology Engineering Laboratory⁽³⁴⁾ (MITEL) was more of a review and provided less detail.

^(a) This study does not estimate or explicitly address values for extra-market production and consumption (externalities) that might be incurred by producing and distributing coal-derived fuels.

The important relationships in Table 6 describe the relative costs of production and distribution and not the absolute costs which are shown in 1973 dollars. Both the Exxon and IGT studies estimate the costs of producing methanol to be higher than the costs of producing synthetic gasoline. When considering distribution costs, which add significantly to the pump price of methanol, the cost advantage of synthetic gasoline becomes even greater.

The high distribution costs of methanol result from the different heating values of methanol and gasoline. Gasoline contains 114×10^3 Btu/gal, whereas methanol contains 58.9×10^3 Btu/gal; only 51.6% of the Btu available in a gallon of gasoline. Thus, nearly twice the volume of methanol must be produced and distributed to provide the same available energy as gasoline. Finally, Table 6 indicates that petroleum gasoline has a sizable cost advantage over synthetic gasoline and methanol at 1973 prices.

The Exxon study by Kant, et al.,⁽²⁵⁾ gives sufficient information for deriving functional relationships between production costs of synthetics and the cost of coal. These relationships, adjusted to 1975 dollars, along with recent petroleum gasoline production costs as a reference, are shown in Figure 6.^(a) The costs of the synthetic fuels represent values for a least cost full scale plant operating under optimal conditions.^(b) Thus, with existing technology and relative prices neither methanol nor synthetic gasoline appears to be competitive at any price of coal. For example, for coal at near zero cost, the production cost of syncrude is estimated to be $\$1.64/10^6$ Btu which is the equivalent of \$9.00/bbl in 1975 dollars.

(a) See Appendix A for derivation of functional relationships. Table A.1 and A.2 also provide information for assessing the impact of improved process efficiencies on product cost as a function of coal cost and by-product credits.

(b) The costs represent minimum short run average costs.

TABLE 6. Comparison of Estimated Production and Distribution Costs of Methanol and Synthetic Gasoline (\$1973/10⁶Btu)^a

	Methanol			Gasoline		
	Prod.	Dist.	Pump (ex. tax)	Prod.	Dist.	Pump (ex. tax)
Exxon ^b	3.43	1.90	5.33	3.06	1.00	4.06
IGT ^c	4.21	1.90	6.11	3.50	1.00	4.50
MITEL ^d	2.41	1.90	4.31	3.25	1.00	4.25
Petroleum Gasoline, 1973 ^e				1.16	1.00	2.16
Petroleum Gasoline, 1974 ^{e, f}				1.82	1.05	2.87

a. Adjusted to coal at \$11/ton (65¢/10⁶ Btu) and 3500 Btu/lb.

b. Ref. 25. Lurgi process for methanol. H-coal process for syncrude.

c. Ref. 32. Koppers-Totzek process for methanol. CSF process for syncrude.

d. Ref. 34. ORNL process for methanol. H-coal process for syncrude.

e. Ref. 23 and various issues of the Oil and Gas Journal and Monthly Energy Review.

f. Assume 11% deflator (CPI) to 1973 dollars - Survey of Current Business, U.S. Dept. of Commerce, p. S8, April 1975.

This chapter has addressed the qualitative differences between methanol, methanol-gasoline blends and synthetic gasoline. The production and cost structures were examined with state-of-the-art technology and varying coal prices. The analysis suggests that synthetic gasoline probably can be produced more cheaply than methanol at this time. When distribution costs are considered, synthetic gasoline appears to have a distinct cost advantage

over methanol. These cost results, coupled with the qualitative advantages of synthetic gasoline over methanol, ruled out further consideration of methanol in this study. The scenarios of the next section attempt to 1) survey future domestic market conditions for gasoline and 2) identify the level to which crude imports must be reduced to encourage market entry of synthetic gasoline.

FIGURE 6. Synthetic Product Cost vs. Coal Cost

6. SCENARIOS

The previous sections of this report covered the demand for gasoline, the predicted future supply of gasoline from domestic petroleum, and the costs of producing methanol and gasoline from coal. This section incorporates the information and results from the previous sections into a simple framework of comparative statics to view the effects of different crude oil import policies on the domestic gasoline market. The indicated effects and projected future time periods for favorable market entry of synthetic gasoline result from three scenarios: "business as usual," "some limitations on imports," and "Project Independence."

BUSINESS AS USUAL

The first scenario addresses the issue of business continuing as usual. This can mean many things: real prices are unchanged; the rate at which real prices are changing remains constant; the rate of change of consumption, imports or capital stock is constant or numerous other possibilities. For this discussion, the rate of change of capital stock (automobiles) and the rate of consumption by this stock will be used to represent a "business as usual" scenario. At present, the automobile stock is growing at an annual rate of 3% while the gasoline consumption per automobile is essentially constant. These trends were applied to 1973 data of 101.6 million cars and a consumption rate of 1040 gallons of gasoline per car per year to project the "requirements curve" of Figure 7. The lower curve in Figure 7 is the projected domestic gasoline production at a 55% conversion of crude oil to gasoline. The area between the two curves represents the additional gasoline which would be "required" if consumption were to follow the path of the upper curve. The implication is that this "gap" would be filled by either imports or synthetic fuels. The area between the two curves represents approximately 56.5×10^9 bbl of gasoline and/or substitutes that would have to be supplied between 1975 and 2000. If the average price of crude oil were \$13/bbl (1975 world delivered price), this would amount to a total of $\$734.5 \times 10^9$ (1975) over the next 25 years.

FIGURE 7. Business as Usual - Projected Domestic Requirements and Supply of Gasoline vs. Time

The above scenario is naive in that consumer responses to higher relative prices, be these in the form of out-of-pocket costs or time and psychic costs of confronting long lines, are not considered. The next two scenarios demonstrate how the "requirements curve" in Figure 7 may be altered by incorporating anticipated consumer behavior into the analysis.

FRAMEWORK OF ANALYSIS

The approach used in the following two scenarios is similar to the methodology presented earlier. Ideally, theoretically sound and empirically validated supply and demand functions for gasoline would be solved simultaneously for any time period to determine the equilibrium quantities and prices. The "supply function" of gasoline produced from domestic crude for this study consists only of projected production rates of

crude oil over time with a percentage converted to gasoline. By accepting these estimated production and conversion rates as being in some way "reasonable" and assuming that whatever is produced in any time period must be consumed in that period, the supply of gasoline, S , from domestic crude in the absence of imports becomes the equilibrium amount of gasoline demanded and consumed, D . That is, for any time period t ,

$$S_t = D_t = f(P_t, Y_t, X_{n,t}). \quad (4)$$

Specification of the gross domestic product per capita for (Y) and the array of other independent variables (X_n) allows the solution of equation (4) for the equilibrium price (P_t). By specifying Y and X_n in succeeding time periods, equilibrium prices may be traced over time. It should be stressed that equation (4) is a static model and the application of this model as suggested here requires some limiting assumptions as well as considerable caution. The coefficients (elasticities) of the demand function, equation (3), are not only constant within the appropriate time period, but are assumed to be constant over time.^(a)

As detailed in the discussion of demand, Adams, et al., were able to demonstrate functional relationships among the independent variables of the log-linear demand function, equation (3). These relationships were considered as a guide along with recent data and current trends in projecting the values of these variables to the year 2000. Different sets of growth rates and trends were hypothesized and used in a simple recursive computer algorithm to solve for the equilibrium price (P_t) in equation (4). The final specifications of the growth rates used to estimate the equilibrium price are:

(a) There are other theoretical considerations. For example, Lau⁽³⁵⁾ has shown that projecting the value of a variable by taking the anti-logarithm of the projected logarithm is not, strictly speaking, a correct procedure.

1) Stock of automobiles	2%
2) Gross domestic product ⁽³⁶⁾	2.3%
3) Population ⁽³⁷⁾	0.85%
4) Average weight of automobiles	-1.5%
5) Average horsepower per pound of auto	0%

Now all that remains to be designated in equation (4) is the supply of domestic gasoline. As stated earlier, this is a function of the projected domestic crude oil production, level of crude imports, and the conversion rate to gasoline. Gasoline production, as a percentage of crude oil input to refineries, has been relatively constant, about 53%, over the past three years. The level of gasoline imported over this period has been averaging 2 to 4% of domestically refined gasoline.⁽²³⁾ As indicated in the supply discussion (Section 4), a 55% conversion rate of crude to gasoline is assumed to represent total domestic supply, including gasoline imports, in any time period.

The partial analysis to the problem requires assumptions about the level of all petroleum imports and prices relative to crude oil. The major necessary assumptions are that the import and petroleum product mixes will remain unchanged along with the relative prices. If the relative petroleum prices change, producers and suppliers would attempt to alter the import and/or product mix to take advantage of the price changes. In fact, this mix has exhibited some recent changes. The ratio of refined imports to crude imports has decreased from about 1.2 to 1 in 1972 to an average of about 0.6 to 1 in 1974.⁽²³⁾ Whether or not ratio changes balance out over time, and the degree to which market regulation has affected this ratio and relative prices are beyond the scope of this effort.

SOME LIMITATIONS ON IMPORTS

The scenario, "limitations on imports," uses the functional relationships of equations (3) and (4) to predict the market equilibrium gasoline prices over time while exogenously specifying the supply of gasoline and growth rates for the independent variables of the demand function. Different levels of imports are considered and market equilibrium gasoline prices are compared to the cost of supplying synthetic gasoline with various prices for coal.

The results of this scenario are presented in Figure 8. The reliability of short-run price predictions using the long-run demand function (equation 3) is open to question. Because of this and the desire to emphasize long-run effects, the abscissa begins at 1978. Two families of curves are shown:

one family of horizontal dashed lines and another family of solid lines flowing generally from the lower left to the upper right. The dashed lines identify the price required to cover the estimated costs of producing

synthetic gasoline at a given price per ton of 8500 Btu/lb coal. For example, the dashed line marked "\$10/ton" intercepts the left-hand vertical axis at approximately 68¢/gal of gasoline. This is the pump price, including tax (12¢/gal), required for the supplier to provide synthetic gasoline to the market. If the price were below 68¢/gal, the supplier would not be able to cover costs in the long run. If the price were above 68¢, the supplier would be earning profits in excess of his expected returns. Thus, 68¢/gal would be the entry point for synthetic gasoline if coal were \$10/ton. The horizontal nature of the dashed lines implies that technology and relative costs of producing synthetic gasoline do not change over time. Improvements in technology or production efficiency, all things being equal, would be represented by the dashed lines remaining parallel but sloping downward slightly from left to right.

The solid lines represent market equilibrium prices (quantities not shown) when domestic production is supplemented by various rates of imports. The levels of imports are given on the vertical right-hand axis. The import levels are shown in 10^6 bbl/day as a percentage of 1974 petroleum imports. The average rate of petroleum imports in 1974 was approximately 6.0×10^6 bbl/day of which about 3.4×10^6 bbl/day were crude and 2.6×10^6 bbl/day were refined products.⁽²³⁾ Thus, imports at a 100% 1974 rate (6×10^6 bbl/day) would be expected to yield about 1.87×10^6 bbl/day of gasoline at a conversion rate of 55%.^(a) The solid line representing 100% of 1974 imports intercepts the left-hand vertical axis at a price of 62¢/gal which is about three cents above the average 1975 pump price.^(23,38)

^(a) Consistency with the assumption of constant product and import mixes yields:

$$\frac{3.4 \times 10^6 \text{ bbl crude/day}}{6 \times 10^6 \text{ bbl total pet. import/day}} \times \frac{0.55 \text{ bbl gasoline}}{1 \text{ bbl crude}} =$$

$$\frac{1.87 \times 10^6 \text{ bbl gasoline/day}}{6 \times 10^6 \text{ bbl total pet. import/day}} = \frac{0.312 \text{ bbl gasoline}}{1 \text{ bbl total pet. import}}$$

If coal were \$10/ton (and if this price in real terms were not expected to change) and if imports were 100% of the 1974 level, the estimated market entry year for synthetic gasoline would be about 1984 (where the "\$10/ton" dashed line crosses the solid "100%" of 1974 imports line). If the level of imports were reduced to 50% of the 1974 level, what might be the effects on decisions to produce synthetic gasoline? The 50% imports line intercepts the left-hand vertical axis at about 74¢/gal. This line, like the others in this family, is predicted to fall to a minimum around 1980 due to increased domestic supply from the Alaskan fields. Recall that this curve represents equilibrium of supply and demand over time. The fact that the predicted equilibrium price falls over time implies that the predicted increases (shifts) in supply would more than offset the predicted increases (shifts) in demand. If coal were priced at \$15/ton, the market entry point for synthetic gasoline would be about 72¢/gal. Thus, synthetic gasoline production would look favorable when compared to the higher gasoline prices. However, if only 3×10^6 bbl/day (5% of 1974 imports) imports were allowed from 1977 to 1982, the contribution to domestic supply from Alaskan oil is predicted to drop the market equilibrium prices below 72¢/gal; that is, below the price necessary to sustain the production of synthetic gasoline with coal priced at \$15/ton.^(a)

Although a number of inferences can be drawn from Figure 8 concerning the impact of import policy, the absolute numbers produced by the analysis should be treated with caution when considered separately. The significance of this effort comes from comparing the absolute numbers; that is, viewing them in relation to one another. For example, Figure 8 indicates that a policy which would freeze petroleum imports at the 1974 level (6×10^6 bbl/day) would raise gasoline prices by an average of 30 to 35% more in the long run

(a) It is realized that the price of coal would also fall with the price of oil.

than a policy which would allow imports to double. This price rise would be equivalent to a 5 to 6% price increase for each 10^6 bbl/day decrease in imports. (a)

Figure 9 is another presentation of the information contained in Figure 8. The curves show the predicted market equilibrium prices for each indicated time period at various percentages of 1974 imports.

FIGURE 9. Equilibrium Gasoline Prices with Constant Supply Projections and Various Coal Prices

(a) Assume 1993 as an average long-run year, then

$$\frac{\text{Price @ 100\% 1974 imports (87¢)} - \text{Price @ 200\% 1974 imports (64¢)}}{\frac{200\% \text{ 1974 imports (12 x } 10^6 \text{ bbl/day)} - 100\% \text{ 1974 imports (6 x } 10^6 \text{ bbl/day)}}{\text{Price @ 200\% 1974 imports (64¢)}}} \times 100$$

The result is 5-6% change in price of gasoline per 10^6 bbl/day petroleum imports.

A number of scenarios can be generated using Figures 8 and 9. For example, based on the dotted line in Figure 9, the increase in gasoline supply from Alaskan crude in 1980 is predicted to not change the real price of gasoline if the absolute level of 1974 petroleum imports is reduced by about 20% in 1980.

PROJECT INDEPENDENCE

The framework for the Project Independence scenario is almost identical to the preceding scenario. The differences involve the assumptions on imports which are decreased linearly (Figure 10) from the 1974 levels to zero by the years 1980 (Curve A), 1985 (Curve B), and 1990 (Curve C). These effects are shown in Figure 10 along with zero imports and imports at 100% of the 1974 level (6.0×10^6 bbl/day of total petroleum products). With zero imports the predicted real (1975 dollars) pump price of gasoline would

FIGURE 10. Equilibrium Gasoline Prices with Reductions in Petroleum Imports and Various Coal Prices

be over \$1.00/gal by 1987. With zero imports (total independence) by 1985, synthetic gasoline would look favorable at or below a real coal price of \$40 to \$50/ton (\$2.35 to \$2.94/10⁶ Btu).

However, prices of oil and coal are not independent. In the long run these two fuels are substitutes with positive cross price elasticities.^{(39-42)(a)} If the output of oil and, thus, consumption should fall, econometric evidence suggests an increase in the price of coal. This was recently experienced with the formation of the Organization of Petroleum Exporting Countries (OPEC) oil cartel. Likewise, with a drop in the price of world oil a reduction of coal consumption would be expected. If the real price of domestic crude oil were to increase with the restriction of imports, the price of coal would be expected to increase also. Consequently, the dashed lines representing constant coal prices and fixed technology in Figure 10 should not be interpreted as predictions of constant coal prices.

The scenario of moving to zero imports of petroleum products appears quite unrealistic. Therefore, Figure 11 is presented as a more realistic possibility. The lower curve (imports doubling by 1990) predicts less than a 20% increase in the real price of gasoline by the year 2000. This would mean importing petroleum at a rate of 16 x 10⁶ bbl/day by the year 2000. For perspective, Table 7 compares total petroleum import projections for the two bottom curves in Figure 11 and the business as usual scenario of Figure 7.

(a) Cross price elasticity is defined as a relative change in quantity of one commodity divided by a relative change in price of another commodity. The cross-price elasticity of coal for oil is

$$\frac{\frac{dQ_{\text{Coal}}}{Q}}{\frac{dP_{\text{Oil}}}{P}}, \text{ while oil for coal is } \frac{\frac{dQ_{\text{Oil}}}{Q}}{\frac{dP_{\text{Coal}}}{P}}$$

FIGURE 11. Equilibrium Gasoline Prices Over Time with Expansion of Petroleum Imports and Various Coal Prices

TABLE 7. Projected Petroleum Imports to the Year 2000 Under Various Scenarios

Scenario	Projected Imports (10 ⁹ bbl)
Imports doubling by year 2000	81.6
Imports doubling by year 1990	100.3
Business as usual	181.1

If imports were to double by the year 2000 and coal prices in real terms were to increase slightly, synthetic gasoline would appear to have a cost advantage early in the next century. However, imports doubling by 1990 is probably a more realistic estimate of what will occur. If this is the case, only technological improvements in conversion processes could make synthetic gasoline attractive in this century.

Recent work at PNL has, in fact, used a supply similar to total domestic consumption predicted under imports doubling by 1990 to estimate capital requirements for various energy supply systems.⁽⁴³⁾ These supply estimates (boxes) are superimposed on Figure 12. This figure allows any supply projection of petroleum products to be easily converted to future market equilibrium price estimates.

SUMMARY

This section addressed three scenarios regarding the domestic gasoline market. An econometric demand function was used with projected supplies of gasoline to demonstrate 1) the effects of supplies, incomes, and other variables on the projected equilibrium prices for gasoline and 2) the importance of these effects and federal import policies on the potential production and marketing of synthetic gasoline under various coal prices.

The next section will discuss the relevance of these results and the limitations of this study. Recommendations will be made where additional research would significantly help to resolve the problems that have been identified but not adequately addressed here.

ESTIMATED EQUILIBRIUM PUMP PRICE FOR GASOLINE AND REQUIRED PUMP PRICE
FOR SYNTHETIC GASOLINE (EACH INCLUDING TAX OF 12¢/gal), \$/gal (\$1975)

FIGURE 12. Equilibrium Gasoline Prices for Constant
Petroleum Supplies with Various Coal Prices

7. SUMMARY AND CONCLUSIONS

CONCLUSIONS

The task of evaluating the potential for producing and marketing gasoline substitutes from coal is quite complex, requiring information on state-of-the-art and future technologies, present and future prices of petroleum and coal, as well as their products, and considerable insight on national energy policy. This study has addressed the problem through a simplified framework of partial analysis by treating the supply and demand for gasoline and the supply of gasoline substitutes from coal. Coupled with assumptions about the level of petroleum imports and refinery mix, the above framework yielded some interesting conclusions:

1) With present technology and prices, gasoline from western coal can be produced and distributed more cheaply than methanol. However, the costs of producing and distributing synthetic gasoline under current prices and technology are 50 to 100% higher than petroleum-based gasoline. It is doubtful that with existing technology this cost advantage will change during the next 25 years.

2) Obviously, considerable uncertainty exists relative to the future prices of gasoline and coal. Synthetic gasoline could have a cost advantage in the near term, but changes in import policy and/or prices could place synthetics at a competitive disadvantage after processing units come on line (8 to 10 years). The industry's relatively large capital requirements coupled with uncertainty over technological improvements probably preclude full-scale production efforts of synthetic gasoline without (a) a federally guaranteed pricing structure or (b) a policy to severely restrict and/or tax imports.

This is a tentative conclusion, based solely on the cost advantages and relative price movements predicted by this study. No potential long-term balance of payment and capital formation problems nor federal policies other than petroleum import policies were considered.

LIMITATIONS

This study employed a framework of partial analysis to provide insights into expected trends and relative price movements. The absolute numbers produced by this analysis should be treated with caution when considered separately from the rest of the presentation. The significance of this study comes from comparing the absolute numbers, i.e., viewing them in relation to one another.

The estimated domestic production of crude oil was not considered to be a function of prices. This resulted in lower estimates of domestic crude oil supplies than would probably exist and, consequently, prediction of higher equilibrium gasoline prices for a given level of imports. The use of a price-sensitive supply function for domestic crude oil would have predicted a greater cost disadvantage for synthetic gasoline and methanol than was shown. The cost disadvantage would have been even larger if the supply and demand of coal had been treated as functions of prices because, in the long run, coal and oil prices tend to move together.

This study treated the fuel substitution problem at a national level and did not attempt to analyze potential markets at the local or regional level. Finally, no assessment was made of probable future improvements in the technological efficiencies of coal synfuels process, which could have significant impacts.

FUTURE RESEARCH POSSIBILITIES

More complete information on several factors would allow a more rigorous treatment of the problem. Incorporation of analytical production and cost functions of resource extraction and processing into a dynamic simulation model would permit a detailed analysis of expected future supply of domestic crude oil and coal. A similar methodological framework with a more complete mathematical description of the different components would be possible. This framework, plus empirically determined demand functions for processed petroleum products and steam coal would provide a comprehensive tool for analyzing the effects of policy and for rigorously investigating some of the more important subtleties which would surface in this type of analysis.

This modeling effort could be supported by interdisciplinary work involving the allocation of costs in advanced multiple production processes, a role traditionally filled by engineers.^(20,44) Engineers use several different methods in allocating costs to jointly produced products. Comparing the results of more than one method applied to the same process can be confusing. Although economists possess a rigorously developed body of theory to deal with multiple production, it has seldom been applied to chemical processes.^(44,45) Considerable information transfer between engineers and economists, an evaluation and potential improvement of the different costing methods, the impact over time of technological improvements on production costs and (perhaps most important to the Pacific Northwest Laboratories Regional Assessment Program) an identification and assessment of externalities could result from this type of interdisciplinary effort.

Another supporting activity that could provide critical information to an overall assessment is research on the external benefits that could be generated from publically supported demonstrations of state-of-the-art conversion technologies. The engineering feasibility of these technologies is not in question. At present, however, the economic feasibility of commercial operations is in doubt. It is reasonable to expect that experience gained in building and operating synfuels plants will result in more efficient production in the future. If the information regarding the experience generated by the potential operation were widely disseminated, many firms would encounter cost reductions. These cost reductions (benefits) would be, of course, external to the decisions of the firm, which would be whether or not to engage in synfuels production (and hence provide the experience). Without some means of internalizing this potential externality (future cost reductions), private decisions based solely upon private benefits and costs may be inefficient from a societal viewpoint. One means of internalizing these potential benefits is by provision of public subsidies. Extensive literature is available on the theoretical and empirical treatment of this type of market failure. Recent work, for example, by Willis has provided a methodology for assessing the impacts of public subsidies in methane production from agricultural wastes.⁽⁴⁶⁾

One component of the general model for which published information is limited is the structure of the domestic coal industry and associated markets and how these are presently changing. In some cases, prices being paid for western mine-mouth coal appear to be significantly higher than the production costs.^(47,48) Thus, a form of economic rent may be accruing to those who control the factors of production (coal resource, labor, transportation). The distribution of these pure profits to the different factors of production is an important consideration, not only from a socio-economic viewpoint, but in predicting future price movements. For example, labor, having some knowledge of these pure profits, may be able to extract larger than normal wage settlements from the mining industry and the suppliers of capital equipment. These factors, with environmental legislation and the rate of capacity expansion in the mining equipment industry and transportation systems should be rigorously investigated in order to understand and ascertain the effects on the future supply and market prices of coal. An appreciation of present and expected future market behavior is crucial for predicting energy production and consumption patterns. Only by doing this can reliable assessments be made of the environmental, social and health effects of energy use.

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Any errors remain the responsibility of the authors.

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APPENDIX A

FUNCTIONAL RELATIONSHIPS BETWEEN PRODUCTION COSTS OF SYNTHETIC FUELS AND COST OF COAL

FUNCTIONAL RELATIONSHIPS BETWEEN PRODUCTION COSTS
OF SYNTHETIC FUELS AND COST OF COAL

TABLE A.1. Estimated Detailed Costs of Jointly Producing
Methanol and SNG from Lurgi Coal Gasification
(\$ 1973)

SNG, MSCF/D	22		
Methanol, T/D	11,338		
LHV, 10^{12} Btu/yr			
SNG	4.9		
Methanol	<u>55.2</u>		
Total	60.1		
Investment, $\$10^6$	475		
Coal cost \$/ton	5	15	25
\$/ 10^6 Btu	<u>.294</u>	<u>.882</u>	<u>1.47</u>
<u>Manufacturing Cost, $\\$10^6$/yr</u>			
Cost feed (7.36×10^6 ton/yr)	36.8	110.4	184.0
Operating cost	35.1	35.1	35.1
Conting. @ 10% (feed + Op. cost)	7.2	14.6	21.9
By-product credit ^(a)	-15.6	-34.1	-52.6
Cap. charges, @ 21.5% inv. ^(b)	<u>102.2</u>	<u>102.2</u>	<u>102.2</u>
Total Product Value	165.7	228.2	290.6
Gas Value			
\$/ 10^6 Btu	2.26	3.27	4.27
Total Gas Value, $\$10^6$ /yr	-11.1	-16.0	-20.9
<u>Methanol Value</u>			
\$/ 10^6 Btu (LHV)	2.80	3.84	4.88
¢/gal	16.49	22.6	28.7
Total Methanol Value, $\$10^6$ /yr	154.63	212.2	269.7

(a) Liquid by-products credit varies with cost of coal.

(b) Equivalent to 10% DCF, adjusted to 8500 Btu/lb coal.

Source: Ref. 25, Vol II, pp. 149-157 and personal communication with A. R. Cunningham, Exxon Research and Engineering Co., Linden, N. J.

TABLE A.2. Operating Costs for Producing 100×10^6 bbl/day
of Synthetic Crude from Sub-Bituminous Coal(a)

		<u>\$10⁶/Yr (1973)</u>		
Liquefaction				
Wages and Salaries	11.7			
Repair Materials (2% of Investment)	8.5			
Supplies, Taxes, etc. (3.5% of Investment)	14.8			
Catalyst and Chemicals	9.8			
Other Costs	2.3			
Hydrogen Manufacturing				
Wages and Salaries	15.0			
Repair Materials (2.25% of Investment)	13.3			
Supplies, Taxes, etc. (3.5% on Investment)	20.7			
Chemicals and Catalysts	4.3			
Subtotal Manufacturing Costs	100.4			
10% DCF Return (0.215 Annual Capital Recovery Factor)	217.9			
Coal at \$5, \$15, \$25/ton (19.8 x 10 ⁶ Tons/Yr)	99.0	297.0	495.	
By-Product Credits				
Sulfur, 117 x 10 ³ long ton/yr @ \$15/long ton	-1.8			
Ammonia, 184 x 10 ³ ton/s yr @ \$50/ton	-9.5			
Fuel Gas, 61.7 x 10 ¹² Btu/yr ^b @ (1.909, 3.228, 4.540)/10 ⁶ Btu	-117.8	-199.2	-280.1	
	<hr/> 288.2	<hr/> 404.8	<hr/> 521.9	
Net Cost for 33.215 x 10 ⁶ bbl/yr				
\$/bbl	8.68	12.19	15.71	
\$/10 ⁶ Btu	1.58	2.22	2.86	

(a) Average heating value of 8500 Btu/lb 1973 dollars.

(b) Fuel gas by-product varies with cost of coal.

Source: Ref. 26, Vol II, p. 131 and personal communication with A. R. Cunningham, Exxon Research and Engineering Co., Linden, N.J.

TABLE A.3. Estimated Costs of Producing and Distributing Synthetic Gasoline^a

Coal Cost		Syncrude Production		Gasoline Refining ^b		Syncrude + Refining		Total, Inc. Dist. Costs of \$1.00/10 ⁶ Btu	
10 ⁶ Btu	\$/ton	\$/bbl	\$/10 ⁶ Btu ^c	\$/bbl	10 ⁶ Btu ^d	\$/bbl	10 ⁶ Btu ^d	\$/bbl	10 ⁶ Btu
0.294	5	8.68	1.57	3.58	0.75	12.26	2.55	17.06	3.56
0.588	10	10.43	1.90	3.81	0.80	14.24	2.97	19.04	3.98
0.882	15	12.19	2.22	4.04	0.84	16.23	3.39	21.03	4.39
1.47	25	15.71	2.86	4.50	0.97	20.21	4.23	25.01	5.22
2.06	35	19.21	3.49	4.96	1.04	24.17	5.05	28.97	6.05

^aProrated for range of coal prices and 8,500 Btu/lb coal 1973 dollars.

^bAssumes plant feed and refinery fuel are functions of syncrude price.

^cHeating value of 5.48×10^6 Btu/bbl syncrude.

^dLower heating value of 4.80×10^6 Btu/bbl syntheric gasoline.

Source: Ref. 25, Vol. II

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