Dr. 1647

MASTL

**Alternative Energy Sources
for Non-Highway Transportation**

Appendices

June 1980

Prepared for
U.S. Department of Energy
Assistant Secretary for Conservation
and Solar Energy
Office of Transportation Programs

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Appendices

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Prepared for
U.S. Department of Energy
Assistant Secretary for Conservation
and Solar Energy
Office of Transportation Programs
Washington, D.C. 20585

Prepared by
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FORWARD

For convenience, the material covered in this study is divided into several reports. Volume I is an executive summary covering the highlights of the study. Volume II is the technical section that covers a summary of the data used in the preliminary screening of the alternate fuels and prime movers as well as the detailed evaluation of each of the four modes from the standpoint of the user, fuel supplier and the engine designer. The detailed discussion and documentation of the data base is in Volume III, which has been subdivided into four areas due to the size of the report. Volume III contains all of the references for the data used in the preliminary screening. The information in the four volumes is as follows.

Volume IIIA contains Sections 1 through 5, and covers the background information on the various prime movers used in the non-highway transportation area, the physical property data, the fuel-prime mover interaction and a review of some alternate energy forms. The five sections are as follows:

Section 1--Prime Movers and Fuels Used in Non-Highway Transportation

Section 2--Criteria to be Used in Evaluating and Rating of Fuels and Prime Movers

Section 3--Physical Property Data

Section 4--Prime Mover-Fuel Interaction

Section 5--Review of Potential for Alternate Energy Forms for Non-Highway Transportation--Fuel Cells, Nuclear and Direct Solar

Volume IIIB covers the economics of producing, transporting, and distributing the various fuels. There are two sections in this volume.

Section 6--Economics of Production

Section 7--Economics of Transportation, Distribution and Storage

Volume IIIC is concerned with the environment issues in production and use of the fuels, the energy efficiency in use and production, the fuel logistics considerations, and the overall ratings and selection of the fuels and prime movers for the detailed evaluation. The seven sections in this volume are as follows:

Section 8--Environmental Impact in Production

Section 9--In-Use Emissions with Alternate Fuels

Section 10--Energy Efficiency in Production

Section 11--Energy Efficiency in Use

Section 12--Fuel Logistics--Resource Availability, Compatibility with
Present Fuel and Distribution System, International/
Military Considerations

Section 13--Overall Rating of Fuels/Prime Movers

Section 14--Selection of Fuels for Detailed Evaluation

Volume IIID covers the demand-related issues. The four sections
are:

Section 15--Energy Supply/Demand Projections

Section 16--Military and International Considerations

Section 17--Institutional Issues

Section 18--Experiment in Probabilistic Forecasting

1. PRIME MOVERS AND FUELS USED IN NON-HIGHWAY TRANSPORTATION

E. N. Cart, Jr.
J. Percival

This section covers the prime mover and fuels in use currently in each of the modes of non-highway transportation. The critical fuel properties for each prime mover are also discussed. A fundamental understanding of the technology in use in each mode and the interaction between the fuel and the prime movers is necessary to evaluate how any alternate fuel could be introduced into the system.

1.1.1 Aircraft Engines and Aviation Fuels

The principal prime mover for aircraft is the aviation gas turbine. In 1976, jet fuel accounted for 95% of the fuel consumed by domestic civil aviation.(1-1) The distribution of fuel usage between domestic civil aviation and military usage in 1976 was 68% used by domestic carriers and 32% used by the military.(1-1)

1.1.1.1 Types of Aircraft Turbine Engines

Each aircraft turbine engine employs the basic Brayton thermodynamic cycle--adiabatic compression, heat addition (combustion) at near constant pressure, and adiabatic expansion through the turbine. Thrust is derived by expanding the turbine discharge gases through a nozzle to produce high velocity resulting in a significant momentum increase and resulting force.

The evolution of the aircraft gas turbine engine over the past forty years has involved many variations of compressor types, combustion configurations and turbine designs and the operating conditions (cycle temperatures and pressures) have changed dramatically. Today's commercial and military aircraft inventory includes a very broad variety of engines which may be categorized into the following six types.

- Turbojet - thrust is derived entirely by expanding the turbine discharge gases through a nozzle to achieve high exhaust velocity. This results in a large momentum increase causing the response force (thrust).
- Turboprop - thrust is derived primarily by a propeller which is driven by the turbine. Consequently, in a single shaft engine the turbine can drive both the compressor and the turbine. Dual shaft engines allow separate turbine stages to supply torque to the compressor and turbine.

- **Turboshaft** - these engines are utilized in helicopter applications. The transmission of torque to the rotor involves an extremely complicated transmission. Again both single and dual shaft engines may be considered.
- **Turbofan** - air entering the engine is split into two separate flows--some air proceeds through the main or core engine (and participates in the Brayton cycle), the remaining air is compressed only slightly (to pressures up to three times ambient) and bypassed around the core engine. Thrust is derived from the combined momentum increase of the core and fan gas flows. Modern turbofan engines derive most of their thrust from the fan airflow which can be up to 6 times the core mass flow rate (a bypass ratio of 6).
- **Afterburning turbojet** - thrust of the turbojet cycle can be augmented by the release of additional energy (combustion of additional fuel) downstream of the turbine discharge. The increased temperature expands the gases resulting in additional exhaust velocity and thrust. This technique allows substantial increases in thrust for little increase in engine weight.
- **Afterburning turbofan** - additional heat release in the fan stream or in the mixed fan and core streams provides additional exhaust velocity and thrust as in the case of the afterburning turbojet.

Each of these engine types is schematically illustrated in Figure 1-1. Table 1-1 lists some important engine characteristics and applications. This illustration highlights the wide variations of existing engine types and different characteristics necessary for specific applications.

1.1.1.2 Aircraft Engine Fuel Consumption

Introduction of the first commercial jet aircraft brought about large increases in the fuel consumed by commercial aviation (see Figure 1-2). Although today's high pressure ratio turbofan engines are far more efficient than earlier jets, fuel consumption is still higher than in piston engines.

Operating characteristics of the aircraft gas turbine are significantly different than the piston engine. The reciprocating engine achieves maximum economy at about half maximum power, but the jet engine becomes more economical at maximum output. Fuel consumption per pound of thrust decreases with increasing flight speed, whereas efficiency of the piston/propeller combination decreases with flight speed. This comes about because of the "ram" effect, i.e., as the aircraft approaches the speed of sound, the inlet air is compressed causing higher inlet pressure, which in turn results in

FIGURE 1-1TYPICAL JET ENGINES IN USE CURRENTLY

Turbojet

Turboprop

Torque to
Helicopter
Transmission

Turboshaft

Turbofan

C - Comp
T - turbine
B - Burner
F - Fan
A/B - Afterburner

Afterburning Turbojet

Afterburning Turbofan

TABLE 1-1

AIRCRAFT ENGINE CHARACTERISTICS AND APPLICATIONS

<u>Type Engine</u>	<u>Examples</u>	<u>Max Compressor Ratio</u>	<u>Bypass Ratio</u>	<u>Application</u>
Turbojet	JT3C, J57	~13	0	Older Commercial Aircraft, High Speed Military Aircraft, Second Generation SST
Turboprop	T56, TPE 331	~7	0	Commercial and Military Short Haul and Transport Aircraft (M = 0.6)
Turboshaft	T53, T63	~7	0	Helicopters
Turbofan	JT3D, JT8D, JT9D, CF-6	13-30	1-6	Current and Modern Subsonic Transport Aircraft (M = 0.9)
A/B Turbojet	J85, J79	6-13	0	Military Aircraft, First Generation SST
A/B Turbofan	TF30, F100, F101	--	--	Advanced Military Aircraft, Second Generation SST

FIGURE 1-2U. S. FLEET FUEL EFFICIENCY
CERTIFIED U. S. CARRIERS

(Interrupted Scenario)

Source: Reference 1-2.

higher compressor discharge pressure and a more efficient thermodynamic cycle. At an altitude where the air is thin and much less thrust is required to overcome aircraft drag, the overall jet aircraft efficiency is highest. It follows therefore that a jet plane must be operated at its design altitude and speed whenever possible to be the most economical in fuel. Much lower ceilings are specified for piston powered aircraft which have severely reduced power at altitude and are not afforded the air compression advantages of the jet's higher flight speed.

Table 1-2 summarizes and compares some important efficiency-related characteristics of various engine types. The turbojet with its increasing efficiency at high speed is suited for supersonic aircraft -- its use in early subsonic commercial aircraft was due to the lack of turbofan technology in the 1950's, in fact, these engines were descendants of the military J57 turbojet used in supersonic military aircraft.

Adding the propeller to the turbine engine (i.e., the turboprop engine) vastly improves fuel economy, i.e., consumption per pound of thrust. Current turboprop engines (most of which are older designs) are roughly equivalent in fuel consumption to piston engines of the same size, about 0.5 lb. of fuel per horsepower per hour.

The turbofan mates the increased flight speed advantages of the turbojet with the efficiency of the turboprop. Advanced technology in the newer engines of the wide-body aircraft (747, DC-10, L-1011) allows compressor pressure ratios of 23-30 and turbine inlet temperatures of 2500°F which results in a very efficient thermodynamic cycle.

Afterburning turbojets and turbofans have characteristics very similar to the corresponding non-afterburning types during the portion of their operation when the afterburner is not in use. However, during afterburning operation significant thrust augmentation (up to 50%) can be achieved. This augmentation is inefficient on a specific fuel consumption basis requiring approximately 2 lb_m fuel/lb_f thrust-hr, but is necessary to accomplish certain types of flight profiles.

From the fuel consumption standpoint, future aircraft operation will be predominantly those of subsonic cruise which utilize turbofan engines. Additional advanced technology can further improve the efficiency of the engines as is recognized by active NASA efforts to develop an energy efficient engine. The E³ (Energy Efficient Engine) program will attempt to demonstrate improved specific fuel consumption through the use of even higher pressure ratios, turbine inlet temperatures, and bypass ratios. Other NASA programs are considering airframe technology advancements to promote overall aircraft fuel conservation.

1.1.1.3 Critical Engine Components

While all the above described engine types are of interest to the subject program, the largest amount of jet fuel currently and in the future will be consumed by commercial transport aircraft with non-afterburning engines. Consequently, the fuel characteristics will affect the engine mainly through influences in the main burner and the fuel system.

TABLE 1-2

TYPICAL PERFORMANCE CHARACTERISTICS OF AVIATION ENGINES

<u>Engine Type</u>	<u>Take Off Thrust/ Engine Weight</u>	<u>Cruise Specific Fuel Consumption</u>	<u>Mach Number Limit</u>
		<u>Lbs Fuel/Hr per Lb Thrust</u>	
Turbojet	4.0	0.84	3.5
Turboprop	6.0	0.53	0.6
Turbofan	5.0	0.7-0.45	0.9
A/B Turbojet	4.5-7	*	3.5
A/B Turbofan	5.0	*	2.5
Piston	2.4	0.5	0.5

*This characteristic would depend upon the amount of thrust augmentation desired. In non-afterburning operation, these engines have SFC similar to their non-afterburning relatives. The SFC, the additional thrust resulting from afterburning operation, is 2.0.

Source: Compiled by ER&E from published information.

1.1.1.3.1 The Combustion System

The function of the main burner is to provide for the mixing of fuel and air within the proper environment to ensure their nearly complete reaction to desirable combustion products. Can, cannular, and modern annular combustors are adequately described in the figure below. In the "primary zone,"

Conventional Main Combustor

fuel and oxidizer are mixed, usually in slightly fuel-rich proportions. Approximately 90 percent of the fuel is burned in this zone. Fuel oxidation is completed in the "secondary zone". In modern engines, turbine inlet temperatures are close to the temperature at which significant chemical reactions cease ($\sim 1600^{\circ}\text{K}$) and no further dilution is required. However, older designs with reduced turbine inlet temperatures utilize a "dilution zone" to further reduce temperature. No significant reaction occurs within this zone.

The purpose of the primary zone is to stabilize combustion. High temperatures resulting from stoichiometric operation promote rapid fuel consumption reactions. Primary zone flow is dominated by a strong recirculation region (established by swirling the air entering the head end or dome of the burner) which furthers combustion stability. In practically all current gas-turbine combustors, the fuel is injected as a liquid. The formation of a well distributed dispersion of small droplets is desirable to promote rapid evaporation of the fuel and intimate mixing of the fuel and air.

The secondary zone introduces additional air to further chemical reactions which consume the products of incomplete combustion passing from the primary zone. Air participating in these chemical reactions is introduced normal to the main flow direction. The remaining air enters parallel to the main flow at the combustor walls to provide a film of cool air which protects the combustor liner. Design of the combustor liner hole pattern to accomplish this requirement traditionally involves a costly development effort to avoid a number of possible detrimental effects. Excessive addition of air may result in quenching chemical reactions (especially carbon monoxide and soot oxidation) essential in reducing emissions. Further, air introduction must be accomplished in a manner which results in a uniform temperature profile entering the turbine; a 25°K increase in gas temperature at a critical

region of a turbine blade can result in a four-fold decrease in blade life. These design objectives must be met within a prescribed combustor length. Although increasing combustor size might facilitate the design task, this would cause undesirable increases in engine length, main shaft size, bearing requirements and engine weight.

A broad list of combustion system performance and design objectives is required of all combustors. Although this list can be quite lengthy, the more important requirements are given below:

- Performance Objectives

- a. High combustion efficiency (100%) at all operating conditions.
- b. Low overall system total pressure loss.
- c. Stable combustion at all operating conditions.
- d. Reliable ground-level ignition and altitude relight capability.

- Design Objectives

- e. Minimum size, weight, and cost.
- f. Combustor exit temperature profile consistent with turbine design requirements.
- g. Good maintainability and reliability.
- h. Minimum exhaust emissions consistent with current specified limitations and regulations.

- 1.1.1.3.2 The Fuel System

The fuel system as described here consists of: a) fuel tanks, b) fuel piping, valves, pumps, meters, and filters, c) the fuel oil heat exchanger, and d) fuel injection equipment. The demands on each of these system components is discussed below.

- a. Fuel Tanks. Aircraft cruising at high altitude are exposed to extremely cold temperatures, care must be taken to prevent fuel from freezing or from attaining a high viscosity. Generally this requires system temperatures to remain above -40°C . However, for certain aircraft flight paths Jet A-1 with a freezing point of -50°C must be used. Other important fuel tank criteria relate to safety aspects of fuel handling, crash safety, and ability to withstand lightning strikes.
- b. Fuel Piping, Valves, Pumps, Meters, and Filters. These components must be designed to avoid excessive wear and provide reliability and easy maintainability. The system must prevent plugging from fuel impurities or vapor lock and avoid unexpected pressure drops such as those which might occur across filters.
- c. Oil/Fuel Heat Exchangers. Cooling for the oil in the aircraft turbine engine is provided by the fuel on its way to the combustor. The temperature of the fuel in the oil/fuel heat exchanger can reach 300°F . Poor heat exchanger design resulting in temperature exceeding this level can result in fuel breakdown and deposit formation. Such behavior can result in loss of heat transfer effectiveness as well as plugging problems.

- d. Fuel Injection Equipment. Both pressure atomizing and air blast (utilizing the momentum of air flowing into the combustor) type fuel injection systems are utilized in today's aircraft turbines. In each case the design must maintain the temperature of the liquid fuel below its thermal stability limit to prevent deposition. This is a very difficult task in today's high temperature systems, especially during engine shut down when heat is transferred to the fuel tank and nozzle under zero fuel flow conditions. Additional difficulties are anticipated in future designs intended to satisfy low pollutant emission requirements. Staged designs for this purpose will not always operate with fuel flow to all injectors. Heat soaking of the fuel during transient operations can cause difficulties directly analogous to afterburner spraybar plugging. A final fuel injection associated problem is carboning or caking within the combustor (i.e. in the presence of oxygen). Carbon formation and deposition can occur if fuel is allowed to impinge on metal parts at certain temperature and pressure conditions.

1.1.1.4 Fuels for Aircraft

1.1.1.4.1 Aviation Gasoline

The U. S. military has standardized its remaining piston aircraft operations to utilize three fuel grades. Recently the lead content of Grade 100 was lowered from 4.6 to 3 ml/gallon to accommodate the smaller engines used in military utility aircraft. ASTM Specification D 910 serves general aviation primarily; a special low lead Grade 100 LL (2 ml TEL/gal) is sold commercially for small piston aircraft as an alternate to Grade 80 which is being phased out of production.

The significant factors in the performance of fuels in aviation piston engines and the important quality features of fuels are:

<u>Significant Engine Factor</u>	<u>Principal Quality Feature Controlled</u>
a. Combustion Characteristics (Detonation)	Antiknock Rating
b. Fuel Metering and Aircraft Range	Net Heat of Combustion
c. Combustion and Vaporization	Volatility
d. Corrosion of Fuel System and Engine	Sulfur, Copper Strip
e. Fluidity at Low Temperature	Freezing Point
f. Cleanliness, Handling Stability	Water Reaction Potential Gum

1.1.1.4.2 Aircraft Turbine Fuels

Three jet fuel types are in wide use throughout the free world. They vary significantly in their distillation characteristics (see Figure 1-3). Specifications for each fuel are listed in Table 1-3. JP-4 is the fuel used by the air forces of NATO, including the United States. Jet B, a fuel essentially identical to JP-4, is used by Canadian commercial airlines. These fuels can be grossly represented as a blend of kerosene and gasoline. The volatility of JP-4 results in a vapor pressure of about 0.17 atm (2.5 psia) at 310°K (100°F), and a flash point below room temperature.

Jet A is the kerosene-based fuel used by most of the world's commercial airlines, including the United States. It has a much lower volatility than JP-4 resulting in a flash point of about 52°C. Because of the reduced probability of post crash fires and the reduction of combat vulnerability, the NATO nation air forces are considering conversion to JP-8. (1-3, 1-4, 1-5) This fuel is nearly identical to Jet A-1, a commercial fuel similar to Jet A in all respects except freeze point (-50°C versus -40°C for Jet A). The combustion characteristics of JP-8, Jet A, and Jet A-1 are virtually identical.

The unique problems associated with shipboard jet fuel use cause the U. S. Navy to use a third fuel type, JP-5, which has an even higher flash point (>63°C).

JP-7 is a special fuel intended for supersonic applications. High flight speed causes additional head load requirements to be imposed on the fuel requiring additional thermal stability. Recent work at Exxon has shown that standard fuels (such as JP-5) can be processed by removing especially troublesome hydrocarbons and deoxygenating the fuel to achieve very high thermal stability.

The fuel characteristics and their potential impact on the engine performance are summarized in Table 1-4. Note that some specification fuel characteristics have been omitted in favor of other fuel descriptions which are considered to be more meaningful measures of the fuel variation. Most notable in this respect is the use of fuel hydrogen content rather than Luminometer numbers or smoke volatility index.

The most serious fuel impacts are on combustion stability and ignition, durability/reliability/maintainability, smoke emission, and fuel system components. Combustion stability and ignition can be influenced by viscosity which detrimentally affects ability to achieve a uniform distribution of small fuel droplets; this prevents rapid vaporization to an ignitable fuel-air mixture. Altitude ignition requirements are particularly critical in this respect. A viscosity of 12 centistokes is usually considered to be the maximum for aircraft applications.

Durability/reliability/maintainability can be seriously affected by fuel hydrogen content or aromatic content. Each of these fuel characteristics affects carbon formation within the combustor. Carbon within the high temperature primary zone causes the flame to be highly luminous with significantly increased emissivity. Radiation from

FIGURE 1-3DISTILLATION CHARACTERISTICS OF COMMON JET FUELS

Source: Compiled by ER&E from published data.

TABLE 1-3

JET FUEL SPECIFICATIONS

Type	Wide-Cut	Kerosene			
Military Designation	JP-4	JP-5	JP-7	ASTM Jet A	(AVTUR 50)
Commercial Designation	ASTM Jet B				ASTM Jet A1
Specification	MIL-J-5624J		MIL-T-28219		(DERD 2494)
Use	NATO Air Forces	NATO Navies	Supersonic	Domestic Airlines	International Airlines
Gravity, ° API	45-57	28-48	44-50	37-51	37-51
Heat Content, Net BTU/# Min.	18,400	18,300	18,700	18,400	18,400
Aromatics, Vol. % Max.	25	26	5	20	20
Olefins, Vol. % Max.	5	5	—	—	—
Smoke Point, Min.	—	19	75*	45*	25
Smoke-Volatility Index	52 min.	—	—	—	—
Corrosion, Cu Strip, Max.	1	1	1 b	1	1
Water Separator Index, Min.	70	85	85	—	—
Existent Gum, Max. mgm/ml	7	7	5	7	7
Potential Gum, Max. mgm/ml	—	—	10	—	—
Sulfur, Wt. % Max.	0.4	0.4	0.1	0.3	0.3
Mercaptan, Wt. % Max.	0.001	0.001	0.001	0.003	0.003
Freezing Point, °C Max.	-55	-46	-43	-40	-50
Viscosity cs max./°F	—	16.5/-30	15/-30	15/-30	15/-30
Thermal Stability Test Temp.	300°F/400°F	300°F/400°F	300/600/600	300°F/400°F	300°F/400°F
AP, in Hg. Max.	3	3	3	3	3
Tube Rating, Max.	<3	<3	<3	<3	<3
Reid Vapor Pressure, psi	2-3	—	—	—	—
Flash Point, Min. °F	—	140	140	100	100
Dist. IBP Min. °F	RPT	RPT	360	—	—
10% Evap. Max. Temp.	RPT	400	385	400	400
20% Evap. Max. Temp.	290	RPT	403	—	—
50% Evap. Max. Temp.	370	RPT	RPT	RPT	RPT
80% Evap. Max. Temp.	470	RPT	500	RPT	RPT
FBP Max. °F	RPT	550	550	572	572

() = British specifications or designations

* Luminometer No.

Source: Compiled by ER&E from published data.

TABLE 1-4FUEL CHARACTERISTICS AND POTENTIAL IMPACT

<u>Combustion System</u>	<u>Principal Quality Feature</u>
<ul style="list-style-type: none">• Combustion Efficiency• Combustion Stability• Ignition (Ground and Attitude)• Size, Weight, Cost• Durability/Maintainability/Reliability• Exhaust Emission	<ul style="list-style-type: none">ViscosityHydrogen ContentAromatic ContentVapor PressureFlash PointDistillation Characteristics
<u>Fuel System</u>	
<ul style="list-style-type: none">• Fuel Tanks• Piping, Valves, Pump, Meters• Oil/Fuel Heat Exchangers• Fuel Injection Equipment	<ul style="list-style-type: none">AromaticsOlefinsThermal StabilityFreeze PointGum

the flame zone can significantly increase the thermal loading on the combustor liner and increases its temperature. This change can significantly reduce component life. Figure 1-4 illustrates the relationship between combustor liner temperature and hydrogen content for a number of engines. The ordinate of this graph is the difference between liner temperature with the given hydrogen content fuel and the liner temperature with a standard fuel (in this case JP-4 with 14.5% hydrogen) normalized by the difference between the JP-4 liner temperature and the combustor inlet temperature. The parameter represents the increased thermal loading on the liner due to the use of a lower hydrogen content fuel. Significant increases in heat transfer are observed. Liner temperature increases of up to 200°F were determined.

The increased carbon formation brought about by lower hydrogen content also results in increased smoke emissions. Figure 1-5 illustrates the significance of this effect for a T56 can type combustor. These results are expressed in terms of SAE Smoke Number, the standard for the aircraft engine industry.(1-6) Viscosity can also detrimentally affect smoke emission by causing maldistribution of fuel resulting in fuel rich operation which also promotes carbon particle formation.

It should be noted that current specifications do not allow the lower hydrogen contents illustrated in Figures 1-4 and 1-5. A jet fuel with the current specification limit aromatic content would have a hydrogen content of 13.5 to 13.8%. Even this level of reduction, however, would seem to have a significant effect on liner temperature and on smoke visibility in the case where the smoke emission with current fuel is on the threshold of invisibility.(1-7)

Key factors affecting the fuel system are aromatics, olefins, and thermal stability as well as freeze point and gum content. Potential problems include fuel breakdown to form deposits and/or gum, plugging fuel system components, depositing of carbon within the combustor, reduction of oil cooling capacity, and viscosity increase or freezing of fuel within the system.

One impact which has been considered previously and is not mentioned in the foregoing discussion is the influence of significantly increased fuel bound nitrogen on NO_x emissions. It is known that nitrogen chemically bound to the fuel molecule is very effectively converted to NO_x (30-90% efficiency of conversion). Present levels are generally less than 20 ppm and contribute negligibly to NO_x formation in comparison with that found from N_2 and O_2 in the combustion air. Previous studies with aircraft type combustors have confirmed this finding in practical hardware.(1-9,1-10) However, discussions at the NASA Hydrocarbon Fuels Workshop generally concluded that fuel storage and thermal stability considerations would limit fuel nitrogen concentration to less than 100 ppm and that this level was broad enough to not limit availability in consideration of petroleum sources. Even this level would not represent a significant contribution to NO_x formed. However, the situation must be re-examined in considering fuels from other sources such as shale oil or coal which are naturally much higher in bound nitrogen. In this case, the possibility

FIGURE 1-4

LINER TEMPERATURE CORRELATION
FOR MANY COMBUSTOR TYPES (1)

(1) Source: Reference 1-8.

FIGURE 1-5

SMOKE EMISSION DEPENDENCE ON FUEL HYDROGEN CONTENT(1)

(1) Source: Reference 1-8.

that research on methods of improving stability and reducing fuel nitrogen conversion may provide technology which allows nitrogen to remain in the fuel must be examined. The pursuit of the most cost effective and efficient energy strategy is the true objective.

1.1.2 Marine Prime Movers and Marine Fuels

The principal prime movers at sea currently are steam turbines and diesel engines. Gas turbines are used to a very limited extent.

The primary considerations in choosing the type of prime mover include capital cost, efficiency, cost of fuel, maintenance, scheduling, size of engine room and manpower requirements. While capital cost of a gas turbine installation is generally lower than for a steam turbine or diesel, efficiency is significantly lower (approx. 22% vs approx. 40% for diesel and approx. 35% for steam). Steam is relatively insensitive to fuel quality; diesel can burn a range of fuels--anywhere from relatively clean automotive diesel oil to Bunker C. On the other hand, the gas turbine generally requires a very clean, salt-free fuel. Of the three prime movers for marine applications, diesels require the highest maintenance, but with modern engines, maintenance can be done cylinder by cylinder while the ship is in motion. The gas turbine has inherently low maintenance and high availability, in the sense that a ship can carry a spare engine, switch when necessary, and perform maintenance by the engine manufacturer on shore. A gas turbine also has small space requirements compared to diesel and steam turbine and is relatively automatic.

The interplay of these factors has influenced trends in the choice of motive power for marine use. Practically all new ships are diesel except for naval vessels which are equipped with gas turbines. The Navy is always concerned with the possibility of ingesting sea-water and losing the engine in a relatively short time during high-speed pursuit. The only way that a gas turbine can be brought up to the efficiency of a diesel is by increasing inlet temperature. Currently, manufacturers have R&D programs underway to develop materials that are not degraded by the high temperatures. Ceramics are seen as the most viable approach. It should be mentioned that the higher the inlet temperature, the more vulnerable is the gas turbine to impurities in the fuel.

1.1.2.1 The Diesel Engine

The diesel engine is a high compression, self-ignition engine. The fuel is ignited by the heat of the high compression and no spark plug is used. The diesel cycle consists of charging the combustion chamber with air; compressing the air; injecting the fuel, which ignites spontaneously; expanding the burned gases; and expelling the products of combustion.

Diesel engines may be grouped according to their speed range in three general classifications as follows:

Slow Speed --Up to 500 RPM
Medium Speed--500 to 1000 RPM
High Speed --Over 1000 RPM

High speed engines of current design and manufacture operate at speeds up to 3000 RPM, and experimental engines have been operated at higher speeds.

The type of service for which the engine will be used determines the speed range. Engines in the slow speed range are built to develop 1000 HP per cylinder at speeds of approximately 80 to 150 RPM. Cylinder bore sizes range up to 36 inches in diameter. Applications for these engines are limited chiefly to large stationary and marine power plants.

Medium speed diesels are available which develop from 100 to 200 HP per cylinder with speeds ranging from 500 to 1000 RPM and cylinder sizes up to 12 inch bore. The applications for this class have been expanding in the smaller stationary and marine power plants, as well as in various industrial installations where flexibility of multiple small units is required. Its chief and greatest volume usage has been in the railroad locomotive field.

The high speed diesel engine has been universally applied to all types of automotive equipment such as trucks, buses, tractors, shovels, construction machinery, power generating sets, small boats, etc. The diversity of application has shown a steady increase. Some developments indicate that speeds of engines normally classified in the medium RPM range will be increased into the high speed classification.

1.1.2.1.1 Diesel Engine Fuel Requirements

Selection of the proper fuel for diesel engines is not a simple procedure but depends upon many variables, the most important of which are:

- Operating speed and load ranges
- Engine size and design
- Frequency of speed and load changes
- Maintenance considerations
- Atmospheric conditions
- Fuel price and availability

Each of the foregoing factors play a part in dictating the fuel to be chosen, the relative influence of each being determined by the specific application and installation involved.

The boiling range of distillate diesel fuels is approximately 300°F to 725°F (150°C to 385°C). The relative merits of the diesel fuel types to be considered will depend upon the refining practices employed, the nature of the crude oils from which they are produced, and the additive package (if any) used.

Under the broad definition of diesel fuel, there exist many possible combinations of various characteristics such as volatility, ignition quality, viscosity, gravity, stability, and other properties. To characterize diesel fuels and thereby establish a framework of definition and reference, various classifications are used in different countries. One of the most widely used is that of the American Society for Testing and Materials,

Committee D-2 on Petroleum Products and Lubricants, known as ASTM D 975-74, Standard Classification of Diesel Fuel Oils. This classification, shown in Table 1-5, covers three grades of diesel fuel oils, No. 1-D, No. 2-D, and No. 4-D. It should be emphasized that Table 1-5 is a classification and not a complete set of quality specifications. In general, it presents certain minimum requirements necessary to assure reasonable operation under the conditions described. Grades 1-D and 2-D are distillate fuels, the type most commonly used in high speed engines of the mobile type, medium speed stationary engines, and railroad engines. Grade 4-D covers the class of more viscous distillates and, at times, blends of these distillates with residual fuel oils. These fuels are applicable for use in low and medium speed engines, employed in services involving sustained loads at substantially constant speed.

While the foregoing classifications deal principally with distillate fuels, residual fuels are used extensively in large, slow speed, marine main propulsion engines and stationary land based engines, principally because of lower fuel cost. More recently, the lower cost aspect has promoted the increasing popularity of residual fuels in some smaller, medium speed marine auxiliary engines. Mixtures of distillate and residual fuels are used in installations where a compromise is sought between the more desirable properties of the former and the lower cost of the latter.

Table 1-6 summarizes the relationship between engine type and fuel quality requirements.

Table 1-7 gives a comparison of distillate and residual marine diesel fuels.

TABLE 1-6
TYPICAL INSPECTIONS OF DIESEL FUELS

Fuel Property	Fuel Type			
	Kerosene	Premium Diesel	Railroad Diesel	Marine Distillate Diesel
Cetane Number	50	47	40	38
Boiling Range, °F.	325-550	360-675	350-675	350-500 (90%)
Viscosity, SSU @ 100°F.	33	35	36	47
Gravity, °API	42	37	34	26
Sulfur, Wt. %	0.12	0.30	0.50	1.2
Uses	High Speed City buses	High Speed Buses Trucks Tractors Light Marine Engines	Medium Speed R. R. Engines Marine Engines Stationary Engines	Low Speed Heavy Marine Engines Large Stationary Engines

Source: Compiled by ER&E from published information.

TABLE 1-5
LIMITING REQUIREMENTS FOR DIESEL FUEL OILS^a
(ASTM D 975-74)

Grade of Diesel Fuel Oil	Flash Point, deg F (deg C)	Cloud Point deg F (deg C)	Water and Sediment, volume percent	Carbon Residue on 10 percent Residue, percent	Ash, weight percent	Distillation Temperatures, deg F (deg C)		Viscosity at 100 F (37.8 C)		Sulfur, ^e weight percent	Copper Strip Corrosion	Cetane Number
	Min	Max	Max	Max	Max	Min	Max	Min	Max	Max	Max	Min
No. 1-D A volatile distillate fuel oil for engines in service requiring frequent speed and load changes.	100 or legal (37.8)	*	0.05	0.15	0.01	...	550 (287.8)	1.4	2.5 (34.4)	0.50 or legal	No. 3	40 ^f
No. 2-D A distillate fuel oil of lower volatility for engines in industrial and heavy mobile service.	125 or legal (51.7)	*	0.05	0.35	0.01	540 ^g (282.2)	640 (338)	2.0 ^h (32.6)	4.3 (40.1)	0.50 or legal	No. 3	40 ^f
No. 4-D A fuel oil for low and medium speed engines.	130 or legal (54.4)	*	0.50	...	0.10	...	...	5.8 (45)	26.4 (125)	2.0	...	30

^a To meet special operating conditions, modifications of individual limiting requirements may be agreed upon between purchaser, seller, and manufacturer.

^b It is unrealistic to specify low-temperature properties that will ensure satisfactory operation on a broad basis. Satisfactory operation should be achieved in most cases if the cloud point (or wax appearance point) is specified at 10 F above the tenth percentile minimum ambient temperature for the area in which the fuel will be used. The tenth percentile minimum ambient temperatures for the U.S. are shown in Appendix A2. This guidance is of a general nature; some equipment designs, use flow improver additives, fuel properties, and/or operations may allow higher or require lower cloud point fuels. Appropriate low temperature operability properties should be agreed on between the fuel supplier and purchaser for the intended use and expected ambient temperatures.

^c When cloud point less than 10 F (-12.2 C) is specified, the minimum viscosity shall be 1.8 cSt and the 90 percent point shall be waived.

^d In countries outside the U.S.A., other sulfur limits may apply.

^e Where cetane number by Method D 613, is not available, ASTM Method D 976, Calculated Cetane Index of Distillate Fuels^g may be used as an approximation. Where there is disagreement, Method D 613 shall be the referee method.

^f Low-atmospheric temperatures as well as engine operation at high altitudes may require use of fuels with higher cetane ratings.

Source: Compiled by ER&E from published information.

TABLE 1-7COMPARISON OF DISTILLATE AND
RESIDUAL MARINE DIESEL FUELS

<i>Fuel Property</i>	<i>Dist. late Marine Diesel Fuel</i>	<i>Low Cost (Residual) Diesel Fuels</i>
Gravity, °API	26	12-16
Viscosity, SSU @ 100°F.	47	1800-5000
Hot Filtration Sediment, Wt. %	< 0.01	0.02-0.15
Carbon Residue, Wt. %	< 0.1	10-13
Ash, Wt. %	< 0.01	0.05-0.10

Source: Compiled by ER&E from published information.

The selection of the appropriate fuel is dependent upon the specific engine and installation involved, and is influenced greatly by the operating conditions prevailing. Because of this, the various fuel properties and their interrelationship with performance are highly important.

1.1.2.1.2 Performance Characteristics of Diesel Fuels

Performance features desired of all diesel fuels, and the physical properties most directly related to them are summarized below. Fuel properties are presented in the order in which they are seen by the engine as the fuel flows from the storage tank, through the fuel system, to the combustion chamber.

<u>Performance Feature Desired</u>	<u>Indicated By</u>
1. Safety in handling	Flash point
2. Pumpability at low temperatures	Pour or cloud point, viscosity
3. Freedom from all suspended matter	Storage stability, suspended sediment tests
4. Readily atomized	Viscosity
5. Readily ignitable	Cetane No.
6. Clean burning	Volatility, Cetane No.
7. Good fuel economy	°API Gravity
8. Major effect on engine wear and deposits	Sulfur

The relationships between fuel characteristics and the performance of the engine, including its accessories, are summarized in Table 1-8.

TABLE 1 - 8
RELATIONSHIP OF FUEL PROPERTIES TO ENGINE PERFORMANCE

FUEL PROPERTY	ENGINE PERFORMANCE CHARACTERISTIC									
	<i>Power Output</i>	<i>Fuel Consumption</i>	<i>Starting</i>	<i>Warmup</i>	<i>Combustion Chamber Deposits</i>	<i>Power Assembly Wear</i>	<i>Injection System Deposits and Wear</i>	<i>Pumpability and Filterability</i>	<i>Exhaust Smoke and Odor</i>	<i>Lubricant and Lubrication</i>
Volatility (Boiling Range)	Low volatility may reduce power due to poor atomization. High volatility may result in inadequate droplet penetration or cause vapor lock, also reducing power.	Low or high volatility may result in high fuel consumption due to improper mixing of fuel and air.	Too high a temperature for 10% evaporated may adversely affect starting.	Fast warmup is, as well as Cetane No. (C.N.), directly related to the front end volatility characteristics of the fuel. The lower the temperature for the 10-50% evaporated, the faster the warmup.	Too high a boiling range or too high a 90% point and end point (E.P.) may cause incomplete combustion and excessive combustion chamber deposits.	Carbon deposits coupled with incompletely burned fuel may promote ring and liner wear.	No direct effect except for possible wear due to vapor lock.	No direct effect.	More volatile fuels tend to reduce exhaust smoke during idle and acceleration. Related to C.N.	Incomplete combustion due to too low volatility may cause lube oil dilution.
Flash Point	Relates to handling hazards. Low flash point may indicate contamination with gasoline or naphtha.									
Ignition Quality	No effect if C.N. is high enough for fuel ignition under light load and low temperature operation. Excessively high C.N. may require readjustment of injection timing.	Same effect as on power output.	Directly affected by C.N. The higher the C.N., the better the starting.	Direct effect. Coupled with high front end volatility, the higher the C.N., the faster the warmup.	Combustion chamber deposits are usually fluffier and more readily purged from engines operated on high C.N. paraffinic fuels.	No direct effect except as C.N. affects completeness of combustion.	No effect.	No direct effect. High C.N. fuels may have high cloud and pour points.	Direct effect. Increase in C.N. usually reduces exhaust smoke and odor at idle and light load. Related to volatility.	No direct effect except as C.N. affects completeness of combustion.
Viscosity	Too low viscosity may cause reduced power output due to pump leakage and also may cause injector wear if combined with poor filtration. Droplet penetration affected by viscosity.	Same as for power output.	No direct effect except as related to volatility.	No direct effect except as related to volatility.	No direct effect except as related to volatility.	No direct effect except as related to volatility.	Too low viscosity combined with poor filtration may accelerate barrel and plunger wear.	Too high viscosity may cause fuel filter collapse, or cause cavitation at low temperatures.	No direct effect except as related to volatility.	Related to volatility. High viscosity fuels may cause incomplete combustion due to poor penetration or mixing of droplets with air.
Cloud Point	No effect.	No effect.	High cloud fuel may plug filter and prevent fuel from reaching combustion chamber.	No effect.	No effect.	No effect.	High cloud fuel may plug filter, thus preventing fuel from reaching injection system and causing wear.	High cloud fuel may cause filter plugging.	No effect.	No effect.
Pour Point	No effect.	No effect.	High pour fuel may plug filter and prevent fuel from reaching combustion chamber.	No effect.	No effect.	No effect.	High pour fuel may plug filter, thus preventing fuel from reaching injection system and causing wear.	High pour fuel may cause filter plugging.	No effect.	No effect.

TABLE 1-8 (Continued)
RELATIONSHIP OF FUEL PROPERTIES TO ENGINE PERFORMANCE

FUEL PROPERTY	ENGINE PERFORMANCE CHARACTERISTIC									
	Power Output	Fuel Consumption	Starting	Warmup	Combustion Chamber Deposits	Power Assembly Wear	Injection System Deposits and Wear	Pumpability and Filterability	Exhaust Smoke and Odor	Lubricant and Lubrication
Sulfur Content	Possible increase in combustion chamber deposits and wear may eventually reduce power output.	Same effect as on power output.	No effect.	No effect.	High sulfur fuel may cause high temperature deposit formation. Deposit formation may also be related to lube oil properties and oil drain intervals.	High sulfur fuel may cause increased ring and liner wear, particularly at light loads.	High sulfur fuel may cause injection system deposits and wear.	No direct effect. High sulfur content may be related to fuel instability, a cause of fuel filter plugging.	High sulfur fuel may adversely affect odor and incrimination.	High sulfur fuel may adversely affect lubricant performance.
Corrosion	No effect.	No effect.	No effect.	No effect.	No direct effect. May increase fuel gum due to attack on brass or copper.	No effect.	May cause corrosion of brass or copper parts in the system.	May cause corrosion of filter assemblies containing brass or copper. High gum formation accelerated by brass or copper parts may cause plugging.	No effect.	May have adverse effect on lubrication due to gum formation.
Stability	No direct effect.	No direct effect.	No effect.	No effect.	Instability may result in deposit formation.	No direct effect.	May cause lacquering of pump and injector parts.	May cause filter plugging.	No direct effect.	May affect lubrication adversely due to gum formation.
Carbon Residue	May cause injector tip deposits, disturbing atomization.	Same effect as with power output.	No effect.	No effect.	May increase deposits if compression ratio is too high.	May cause increased wear.	May cause injector tip deposits and seizure of injection system parts.	May cause filter plugging.	May cause increased smoking.	May increase burden on the lube oil.
Ash	May cause wear which will indirectly affect power output.	Same as for power output.	No effect.	No effect.	Excessive ash may increase deposit level and affect nature of deposits.	Excessive ash may aggravate wear.	High ash may cause abrasion of injector system parts.	No direct effect.	No direct effect.	No direct effect.
Water and Sediment	No effect.	No effect.	No effect.	No effect.	No direct effect.	May increase wear if material passes into combustion chamber.	May increase deposits and wear.	May cause filter plugging.	No direct effect.	No direct effect.
Gravity	Low gravity (API) fuels may increase power output due to higher heating value per unit volume.	Fuel economy may improve for given throttle setting for low gravity (API) fuels due to higher heat content per unit volume.	No direct effect. Related to C.N. and volatility.	No direct effect. Related to C.N. and volatility.	No direct effect. Related to C.N. and volatility.	No direct effect.	No direct effect.	No direct effect but related to volatility and viscosity.	No direct effect, but related to C.N. and volatility.	No direct effect, but related to C.N., volatility, and viscosity.

Source: Compiled by ER&E from published information.

1.1.2.2 The Steam Turbine

The earliest steamships were mostly fitted with fire-tube cylindrical boilers termed the Scotch marine type. Simple water-tube boilers consisting of inclined tubes between headers were widely used from 1897 right through the first and second World Wars.

Boilers are designed to meet specific requirements of many types of vessels, ranging from tugboats to ocean liners, battleships, and aircraft carriers. Steam conditions vary widely, from 150 psi to about 2700 psi design pressure, and up to steam temperatures of about 1000°F (538°C). Steam demand may range from 2000 to 300,000 lb/hour. Operation will vary with the type of ship and its service. Passenger vessels, cargo ships, and tankers, which operate on schedule may be expected to place a steady load on the boilers at the designed normal power rate. The steam load for dredgers and tugs fluctuate greatly, and for that kind of operation the boiler should be fitted with large steam drums and have an effective method of superheat control. Navy combat ships are designed to have maximum efficiency at about 25% of rate horsepower since such ships cruise at this power most of their service lives. However, the boilers must be capable of sustained operation at 120% of full power rating without undue maintenance.

In a general way, the main difference between marine boilers and their counterparts on land is that the marine equipment is fired at a much higher heat release rate. For example, heat release rates within the furnaces of many land-based boilers are between 25,000 and 30,000 BTU/cubic foot/hour, whereas at sea a common rate would be 60,000 to 70,000 and in Navy vessels it could be as high as 500,000.

In the burning of Bunker C fuel oil at such high inputs, certain minimum clearances are required around the burners to prevent flame impingement and carbon deposits on the furnace walls.

1.1.2.2.1 Steam Turbine Fuel Requirements for Marine Applications

Steam driven ships usually require Bunker C fuel. International bunker fuel is Bunker C, in effect the heaviest member of the intermediate fuels class. A viscosity of 4000 Redwood No. 1 or 175 SSU at 122°F (50°C) is normally considered maximum. The principal requirement for Bunker C which might differentiate it from the corresponding heavy fuel oil for land use is that of gravity. A minimum of 12.5°API is normally required to insure good separation from sea water contamination.

Sulfur content cannot be ignored but it is less important at sea than on land, especially in some urban areas.

Marine boilers are almost invariably designed to fire Bunker C and to withstand the deleterious effects of a reasonable amount of ash components and sulfur in the fuel. Obviously, boiler maintenance can be reduced by purchasing fuels containing less of these normal contaminants, but the economies so effected will seldom pay for the premium fuel. Several

shipping companies have elected to use the heaviest fuels available, and it is not too uncommon to find 400 SSF/122°F fuels being used by tanker companies. These heavier fuels simply need to be heated to a slightly higher temperature for atomization than do the conventional 100 to 175 SSF/122°F fuels.

1.1.2.3 The Gas Turbine Engine

A simple gas-turbine engine consists of a compressor, a combustion chamber and a turbine. The aim is to convert heat energy of fuel into mechanical energy. The compressor and combustion chamber produce a high-energy working fluid that can be expanded in the turbine which develops mechanical energy.

Manufacturers are offering a wide range of gas turbine power plants for non-aviation applications. The engines range from approximately 2500 hp to approximately 20,000 hp. Applications have been studied and designed in many fields including gas transmission power generation, marine propulsion, railroad propulsion, factory standby power, and process applications. In most cases, the final component, whether it be a generator, compressor, a ship's propeller, or other device, is driven by a power turbine. This power turbine has no direct connection with the aircraft gas turbine engine but utilizes the gases from the gas turbine engine as its source of energy. Thus, the gas turbine engine becomes, in effect, a gas generator. This system offers the advantage of eliminating the monumental problems which are encountered in a direct shaft drive which requires elaborate gearing for speed reduction.

The advantages offered by this type of prime mover are significant for many applications. Of principle interest is the considerably lower capital investment required for a gas turbine installation when compared to a reciprocating installation of equivalent output. Published articles have cited figures as high as a 50% saving. In many cases, the possibility of automation or remote control brings about significant savings in direct operating cost which in many applications offset the higher fuel consumption which is, at present, a basic shortcoming of the gas turbine engine. Other published articles have cited the ability of the gas turbine powered generating units to go "on stream" in a matter of minutes as compared to many hours required for a steam turbine unit.

1.1.2.3.1 Gas Turbine Fuel Requirements

The growing use of aircraft turbine engines in a variety of industrial applications raises questions as to just how these engines perform on fuels other than conventional aviation gas turbine fuels. The indications are that although boiling point, specific gravity, surface tension and heat of vaporization all theoretically influence burning time requirement, these factors are so interrelated in normal petroleum fuels that they cancel one another. Thus, for a given viscosity, boiling range can be varied widely without changing burning time requirements appreciably.

The question of viscosity range is important, especially when the turbine is one which is fired through multiple small combustion chambers

(combustion cans). It is less important for turbines with single large chambers. The smaller cans are fired by small pressure atomizing nozzles. The spray angle and the degree of atomization are adversely affected by too high a viscosity, this can be especially important at the moment of starting the engine. Once the turbine is running at full power, the fuel viscosity can be increased to 10 centistokes, or up to 20 centistokes if air atomizing nozzles are used. At the lower end of the viscosity range some manufacturers express concern for pump maintenance due to poorer lubricating properties of the fuel.

Another critical point in the gas turbine is the combustion can liner, which may become choked with carbon if the combustion is not clean, or which may become overheated if radiation from the flames to the walls of the can is excessive.

As was discussed under aircraft fuels, the problem of flame radiation is controlled by specifying a maximum luminometer number (ASTM D1740), or a maximum smoke number (ASTM D1322). These tests correlate with the paraffinicity of the fuel, that is, better results are obtained the higher is the ratio of hydrogen to carbon in the fuel.

In the industrial turbine field, much of this criticality has been designed out by the introduction of cans which are larger and heavier than those which are needed in aircraft. However, directionally there is an advantage for fuels of higher hydrogen content. The U. S. Navy specifies a minimum cetane number of 39 for distillate fuel for gas turbine use. The turbine is not critical to cetane rating as such (nor to octane rating since ignition is continuous), but the figure of 39 is intended to insure that the fuel does not contain too much aromatic component.

The American Society for Testing and Materials has recently published a standard specification for gas turbine fuel oils (ASTM D 2880-76) for uses other than in aircraft. The properties selected for limitation are those that are believed to be of greatest significance in determining performance characteristics of the fuels in the various gas turbine applications. These are listed in Table 1-9.

The properties listed in this specification are those of greatest significance in obtaining acceptable performance of the turbine. However, trace metals, even in fractional parts per million, are detrimental to gas turbine service life. Information on the maximum concentration of critical metallic elements in the fuel as it enters the turbine combustor(s) is provided in Table 1-10. Distillate fuels are usually of satisfactory purity as refined, but suppliers rarely have control over possible contamination by trace metals in distribution and storage. The limits, although required as the fuel enters the combustor(s), do not apply to the fuel as delivered unless mutually agreed upon by the interested parties. Fuels may, therefore, require on-site clean-up, quality control procedures, special handling, or other arrangements.

TABLE 1-9

**DETAILED REQUIREMENTS FOR GAS TURBINE FUEL
OILS AT TIME AND PLACE OF CUSTODY TRANSFER TO USER**

(ASTM D 2880-76)

Designation ^a	Grade of Gas Turbine Fuel Oil	Flash Point, °C (°F)	Pour Point, °C (°F)	Water and Sediment, vol %	Carbon Residue on 10 % Residue, wt %	Ash, wt %	Distillation Temperature, 90 % Point		Saybolt Viscosity, s ^b			Kinematic Viscosity, mm ² /s ^b			Gravity, ° API	Sulfur, wt %
							°C (°F)	°C (°F)	Universal at 38°C (100°F)		Furol at 50°C (122°F)	at 38°C (100°F)		at 50°C (122°F)		
		min	max	max	max	max	min	max	min	max	max	min	max	max	min	max
No. 0-GT	A naphtha or other low-flash hydrocarbon liquid.	c	...	0.05	0.15	0.01	...	...	c	...	...	c	...	...	...	legal
No. 1-GT	A distillate for gas turbines requiring a fuel that burns cleaner than No. 2-GT.	38 (100) or legal	-18 ^b (0)	0.05	0.15	0.01	...	288 (550)	...	(34.4)	...	1.4	2.5	...	35	legal
No. 2-GT	A distillate fuel of low ash suitable for gas turbines not requiring No. 1-GT	38 (100) or legal	-6 ^b (20)	0.05	0.35	0.01	282 (540)	338 (640)	(32.6)	(40.2)	...	2.0	4.3	...	30	legal
No. 3-GT	A low-ash fuel that may contain residual components.	55 (130) or legal	...	1.0	...	0.03	...	...	45	...	300	(5.8)	...	(638)	...	legal
No. 4-GT	A fuel containing residual components and having higher vanadium content than No. 3-GT.	66 (150) or legal	...	1.0	...	...	...	...	45	...	300	(5.8)	...	(638)	...	legal

^a No. 0-GT includes naphtha, Jet B fuel, and other volatile hydrocarbon liquids. No. 1-GT corresponds in general to Specification D 396 Grade No. 1 fuel and Classification D 975 Grade No. 1-D diesel fuel in physical properties. No. 2-GT corresponds in general to Specification D 396 Grade No. 2 fuel and Classification D 975 Grade No. 2-D diesel fuel in physical properties. No. 3-GT and No. 4-GT viscosity range brackets Specification D 396 Grade No. 4, No. 5 (light), No. 5 (heavy) and No. 6 and Classification D 975 Grade No. 4-D diesel fuel in physical properties.

^b Viscosity values in parentheses are for information only and are not limiting; (1 mm²/s = 1 cSt).

^c When flash point is below 100°F, or when kinematic viscosity is below 1.4 cSt at 100°F, or when both conditions exist, the turbine manufacturer should be consulted with respect to safe handling and fuel system design.

^d For cold weather operation, the pour point should be specified 5.6°C (10°F) below the ambient temperature at which the turbine is to be operated except where fuel heating facilities are provided. When a pour point less than -18°C (0°F) is specified for Grade No. 2-GT, the minimum viscosity shall be 1.8 cSt (32.0 s. Saybolt Universal), and the minimum 90 % point shall be waived.

Source: Compiled by ER&E from published information.

TABLE 1-10

TRACE METAL LIMITS OF FUEL ENTERING TURBINE COMBUSTOR(S)

Designation	Trace Metal Limits (max), ppm by wt.			
	Vanadium (V)	Sodium plus Potassium (Na + K)	Calcium (Ca)	Lead (Pb)
No. 0-GT	0.5	0.5	0.5	0.5
No. 1-GT	0.5	0.5	0.5	0.5
No. 2-GT	0.5	0.5	0.5	0.5
No. 3-GT	0.5	0.5	0.5	0.5
No. 4-GT	(Consult turbine manufacturers)			

Trace metal limits are significant in terms of affecting power output and turbine life. Vanadium can form low melting compounds such as vanadium pentoxide which melts at 691°C (1275°F), and causes severe corrosive attack on all of the high temperature alloys used for gas turbine blades.

- Lead can cause corrosion and in addition it can spoil the beneficial inhibiting effect of magnesium additives on vanadium corrosion.
- Sodium, potassium, and calcium--Fuel contaminants might also include fuel insoluble materials such as water, salt, or dirt, potential sources of sodium, potassium and calcium. These are normally removed at the gas turbine site, unless such contaminants are extremely finely divided.
- Sodium and potassium can combine with vanadium to form eutectics which melt at temperatures as low as 566°C (1050°F) and can combine with sulfur in the fuel to yield sulfates with melting points in the operating range of the gas turbine. These compounds produce severe corrosion, and for turbines operating at gas inlet temperatures above 649°C (1200°F) additives are not yet in general use which control such corrosion.
- Calcium is not harmful from a corrosion standpoint; in fact, it serves to inhibit the corrosive action of vanadium. However, calcium can lead to hard-bonded deposits that are not self-spalling when the gas turbine is shut down, and that are not readily removed by water washing of the turbine.
- Sulfur, normally burning to sulfur dioxide, also can be oxidized partially to sulfur trioxide which then can combine with sodium and potassium compounds from the ash in the fuel to form sulfates, pyrosulfates, and such compounds as sodium or potassium iron trisulfate. The pyrosulfates, and the trisulfates have melting points in the operating range of the gas turbine. Hence, the compounds produce severe corrosion of the turbine blading.

1.1.3 Railroad Prime Movers and Fuels

The primary prime mover used by the railroads in the U. S. today is the diesel engine. The steam locomotive has all but disappeared, and the present trend is against further expansion of electrical operation because of high initial costs. In replacing the steam locomotive, the modern diesel has lowered operating and maintenance costs and reduced the number of locomotives necessary to maintain adequate service. The distribution of locomotives as of January 1, 1976 is shown below. (1-11)

LOCOMOTIVES OF U.S. CLASS I RAILROADS

<u>Type</u>	<u>Number</u>
Diesel	27,925
Electric	215
Steam	1

Power is developed by a diesel engine driving a generator, which in turn feeds electric traction motors mounted on each axle. This type of power transmission is easy to control and accounts for the efficiency of the diesel at all speeds under most load conditions.

Railroads have obtained greater use from diesels than from steam or electric units because the diesel can perform many different jobs efficiently and spends less time in the shop for maintenance, both routine and major. Diesel maintenance is less time-consuming because there are many interchangeable parts--whole motor generator sets can be replaced and a unit quickly restored to service.

The type of diesel most frequently used is the general-purpose road switcher. It has been successful on all railroads, hauling fast passenger trains, long-haul freights, and local commuter trains, and is also used in both local and interchange yards. Other types are designed especially for fast passenger or freight service and differ primarily in gear ratios and horsepower ratings. Railroads and coal companies have also considered using coal-burning steam turbines but an economically practical design has not been developed.

1.1.3.1 The Railroad Diesel Engine

Diesel locomotive engines having continuous power capabilities from 500 to 4000 horsepower are available. The engines generally operate in an intermediate speed range, that is, from 600 to 2000 rpm, with 900 to 1000 rpm being most common in the larger sizes. On U. S. mainlines the most common locomotive is the diesel-electric. For the small and medium size shunting locomotives, diesel-mechanical or diesel-hydraulic systems are generally used. On the larger shunting locomotives the diesel-electric unit is popular, and in recent years an increased number of diesel-hydraulics have been put into service, particularly in Europe.

The diesel engine for railroad locomotives has been developed into an extremely reliable piece of machinery whose configurations and size fit in very well with the space limitations imposed by railroad requirements. Its outstanding feature is its relatively high thermal efficiency of 32 to 35%, which is consistently maintained in service over a wide range of loads and speeds. Since fuel costs are a substantial part of locomotive operating costs, this is a very important attribute. Another major advantage is its operational availability due to its relatively low maintenance downtime.

Although the demand for diesel power has been high in all fields of application, the volume of diesel horsepower being channeled to railroad diesel locomotives exceeds all other industrial applications. Some of the advantages of the diesel engine over the steam locomotive in railroad operation are illustrated in Table 1-11, which compares the performance of switching, freight, and passenger engines in terms of heat input per unit of useful work.

TABLE 1-11

COAL FIRED STEAM vs.
DIESEL LOCOMOTIVE OPERATION

<u>Switching Engines</u>	<u>10⁶ BTU/Loco. Hr.</u>
Coal Fired Steam	11,300
Diesel	850
Ratio Coal/Diesel	13.3
 <u>Freight Engines</u>	 <u>BTU/Ton Mile</u>
Coal Fired Steam	1,665
Diesel	224
Ratio Coal/Diesel	7.4
 <u>Passenger Engines</u>	 <u>10⁶ BTU/Car Mile</u>
Coal Fired Steam	232
Diesel	39
Ratio Coal/Diesel	6.0

Basis: Coal - 12,710 BTU/Lb. (Net)
 Diesel Fuel - 132,200 BTU/Gal. (Net)

Source: Compiled by ER&E from published information.

In switching service, a typical steam locomotive requires 13 times the heat input of a diesel engine per locomotive hour.

1.1.3.2 Diesel Engine Fuel Requirements

Information on diesel fuels in general can be found in the discussion of diesel fuel requirements for marine diesels (1.1.2.1.1). Most of the railroads in the U. S. use a fairly good grade of all-distillate ASTM No. 2 diesel fuel, as specified in ASTM D 975-74. Specific recommendation supplementing these requirements are also made by major manufacturers. These are shown in Table 1-12.

The distillate fuels described in Table 1-12 give very good results. However, extensive test work has indicated that cheaper, lower quality distillate fuels can be utilized in railroad diesel engines. Representative inspection data, comparing an economy grade diesel fuel, are shown in Table 1-13.

TABLE 1-12

FUEL RECOMMENDATIONS - U.S. LOCOMOTIVE DIESEL ENGINES

Inspections	ASTM Designation	Manufacturers		
		General Motors Corp. Electromotive Div.	General Electric	
			Class A	Class B (a)
Cetane Number, min.	D-613	40	45	40
90% Point, °F, max.	D-86	650	650	675
Final Boiling Point, °F, max.	D-86	700	700	-
Distillate Recovery, %, min.	D-86	99.0	-	-
Total Sulfur, %, max.	D-129	0.5 (b)	0.75	1.0
Corrosive Sulfur (3 hr. @ 122°F)	D-130 (Mod)	#2 or better	#3 max.	#3 max.
Con. Carbon Residue, 10% btms., max.	D-189	0.15	0.15	0.35
Water & Sediment, %, max.	D-96	0.05	0.05	0.10
Cloud Point, °F, max.	D-97	(d)	-	-
Pour Point, °F, max.	D-97	(d)	(e)	(e)
Flash Point, °F, min.	D-93	150	125 or legal	125 or legal
Viscosity @ 100°F, Kinematic, cs.	D-445	1.8-5.8	1.8-5.8	1.8-5.8
Viscosity @ 100°F, SSU	D-88	32-45	32-45	32-45
Organic Chlorides, ppm, max.	UOP #395	20	-	-
Filtration Cleanliness Test, mg./l. max.	(h)	1.3 (g)	-	-
Ash, % by wt., max.	D-482	0.02	0.02	0.02

- (a) Use of Class B fuels will require additional maintenance and more careful control and selection of lubricating oil.
- (b) The maximum total sulfur content has been set at 0.50% or legal. Fuels containing larger amounts of sulfur can be used but will increase engine wear and maintenance.
- (c) Low atmospheric temperature as well as engine operation at high altitudes may require use of fuels with higher cetane ratings.
- (d) Prevailing ambient temperature.
- (e) For cold weather operation, the pour point should be specified 10°F below the ambient temperature at which the engine is to be operated, except where fuel oil heating facilities are provided.
- (f) For normal summer operations, a pour point of 25°F maximum is satisfactory. For winter conditions the oil should have a pour point not less than 10°F lower than the expected temperatures.
- (g) Ash residue on 0.80 micron filter.
- (h) 1962 ASTM D-2 Report, Appendix X, page 35.

TABLE 1-13INSPECTIONS OF RAILROAD DIESEL DISTILLATE FUELS

<u>Inspection</u>	<u>High Grade</u>	<u>Economy Grade</u>
Cetane No., min.	50	40
Sulfur, %, max.	0.2	0.75
FBP, °F, max.	625	725
Pour Point, °F	0-15	30-70
Relative stability	Excellent	Good to Fair

Since fuel costs constitute over half the operating expense of the railroad diesel locomotive, a reduction of unit fuel cost could result in large potential savings. As fuel quality is degraded, however, maintenance costs tend to increase. It thus becomes a matter of economics whether the price of the economy fuels is low enough to show a saving after paying for the added maintenance.

Use of economy grade distillate fuel may result in fuel cost savings from 5 to 10%. Further reductions in the cost of these fuels are not possible as long as all-distillate fuels are specified, because even the lower grade distillates are well refined products which are in high volume demand for other commercial purposes.

A great deal of work has been done on blends of distillates with lower cost residual fuels. The use of residual fuels in the diesel engine is as old as the engine itself. Throughout the years it has been common practice to operate large slow-speed marine and stationary diesel engines (especially those of European design) on black fuels of various viscosities. In many instances, distillate fuels have been used for starting up, shutting down, and maneuvering under part load. In the shipping industry this practice has resulted in satisfactory economical operation. The majority of commercial motor vessels throughout the world are now using residual fuels in their main propulsion diesel engines, and there is a growing tendency toward using such fuels in their auxiliary engines also. In the U.S.A. residual fuels are used much less extensively in diesel power, especially in medium and high speed engines.

The use of full viscosity Bunker C fuel does not appear feasible in railroad diesel engines, but blends of residual fuel with distillates have been field-tested.

1.1.3.3 Railroad Gas Turbine Engine

The gas turbine has appeal as a locomotive power plant because it is simple, compact and requires no cooling water. It has inherently low maintenance and high availability (low down-time) characteristics, and high-powered units can be built within a single cab.

Amtrak has taken delivery of the first of seven turbine-powered trains from Rohr Corporation. These trains were built under a license agreement with the French firm which had supplied six Turboliners to Amtrak and contain many of the same French components.(1-12)

1.1.3.4 Railroad Electric Motive Power

Electric locomotives constitute only a small part of the total railroad prime mover population, and these are concentrated primarily in the Northeast Boston-New York-Washington corridor. Some views on the subject of electrics are given in a recent paper, "Electrification and New Electric Locomotive Designs," presented by M. Ephraim, Jr., Chief Engineer, and H. E. Quinn, Chief Electrical Engineer, of GM Electro-Motive Division.(1-13)

Ephraim and Quinn stated that, "Whereas European experience indicates that electric locomotives are comparable in cost to diesel-electric locomotives, this is definitely not the experience in the United States to date." Tooling expenses would be considerable to bring the industry's electric locomotive manufacturing capabilities up to a level comparable with the equipment and plant the industry now has on-line after the more than 30 years of manufacturing diesel-electric locomotives:

"Electric locomotives to date have not been mass produced to the same degree as the diesel-electric locomotive, and it will be a long time before sufficient quantities of standardized models will be required to justify the enormous tooling expenditures to minimize production costs. As an example of higher costs of electric-powered cars produced in limited quantities, a typical MU electric rail car in the United States costs approximately 60% more than a high-horsepower diesel locomotive, and an Amtrak Metroliner car is estimated to cost over twice as much as a diesel-electric locomotive, if reordered today."

1.1.4 Pipeline Prime Movers and Fuel Interaction

The prime mover selected for developing the pumping pressure in pipelines is generally related to the fuel available. The ideal situation is to use some of the material being pumped as the fuel; thus, natural gas pipelines operate mostly with reciprocating spark ignited engines fueled by natural gas. Gas turbines can also be used, since they operate well on natural gas, but they are less efficient, consuming approximately 35-40% more fuel. However, they are used in remote locations where cooling water is not available.

Crude and liquid product pipelines generally utilize centrifugal pumps run by electric motors. The distribution of prime movers used in pipelines in 1970-71 is shown in the following table.

TYPE OF ENGINE/DRIVE USED TO TRANSPORT
PETROLEUM & NATURAL GAS BY PIPELINE (1-11)

1970-71

	<u>10¹² BTU</u>
Gas Reciprocating	420
Gas Turbine	275
Diesel	45
Electric	328

Source: Reference 1-1.

1.1.4.1 Gas Engine Prime Movers

Gas engines are built in size ranges up to 12,500 H.P. Approximately 80% are 2 cycle, and the remainder are 4 cycle engines. Besides the obvious operating difference, the main distinction between the two types is the design of the power cylinders. A two-cycle engine has two sets of ports or openings around each power cylinder wall. Fuel is injected through a nozzle at the top of the cylinder. On the other hand, four-cycle engines such as the Ingersol-Rand utilize inlet and exhaust valves to admit the air-fuel mixture and exhaust the products of combustion.

In operation, the four-stroke cycle gas engine works just like the engine in an automobile. The only significant difference is the nature of the fuel. Where the gasoline engine uses a vaporized petroleum fuel, the gas engine uses natural gas.

As in the carburetor of the automobile engine, fuel and air are mixed together for delivery to the combustion chambers. In a gas engine, the equivalent of a carburetor is called a mixing valve. Spark plugs ignite the fuel-air mixture in the power cylinders at the appropriate time. Electric impulses to the spark plugs are provided by magnetos. Inlet and exhaust valves are operated by cams and rocker arms just as in an automotive engine.

In actual practice, both the power and compressor cylinders are integrally constructed on the same frame and all pistons are connected to one crankshaft. Power developed in the engine cylinders is transmitted through connecting rods and the crankshaft directly to the compressor all within a common engine-compressor frame.

1.1.4.1.1 Gas Engine Fuel Requirements

In gas engines, resistance to detonation and knock is probably the major fuel performance consideration. Detonation is characterized by excessive and extremely rapid rises in combustion pressure. These violent rises signify uncontrolled combustion, accompanied by loss in efficiency.

In addition, detonation leads to audible knock, a post-ignition phenomenon. Knock occurs when an advancing flame front compresses the remaining charge so that its temperature exceeds its ignition temperature, causing spontaneous ignition to take place. Although occasional detonation is not harmful, prolonged periods of detonation can induce preignition. Preignition can generate excessively high temperatures within the combustion chamber in a period of a few seconds, and in so doing, can destroy piston crowns and valves.

The following four factors influence detonation and knock:

- Fuel characteristics
- Compression ratio
- Ignition timing
- Mixture temperature

Definite relationships exist between these factors. These relationships are summarized briefly as follows:

- As the compression ratio increases, there is an increased tendency for the engine to detonate.
- There is an increased tendency for the engine to detonate as the spark ignition timing is advanced.
- An increase in mixture temperature increases the tendency of the engine to detonate.
- Detonation can be suppressed by an improvement in fuel antiknock properties.

The antiknock properties of gaseous fuels (and gasolines) determine their resistance to detonation. Antiknock properties vary with molecular size and structure. Antiknock quality decreases with increasing molecular weight for a given molecular configuration, and generally increases as the number of branched chains in the molecule increases. For example, methane, CH_4 , has less tendency to knock than has butane, C_4H_{10} .

1.1.4.2 Gas Turbine Primary Movers

Except for their lower efficiency (relative to gas engines), gas turbines make good prime movers for pipeline pumping. Experience has shown that they operate well as drivers for compressors (natural gas service) or centrifugal pumps (liquid product service). One current example of application of gas turbines in a remote location is the Alaska Pipeline.(1-14) At full design capacity of 2 MMbpd, the system will have 12 pump stations. Centrifugal pumps powered by 13,500 hp aircraft-type turbines will, at full system capacity, provide almost 650,000 hp. Four of the pump stations will be fueled by natural gas from the Prudhoe Bay field; the remaining stations will use fuel derived from the crude.

The fuel requirements for a gas turbine engine discussed under the Marine section (1.1.2.3.1) generally apply here as well.

1.1.4.3 Electric Motor Prime Movers

Crude and liquid product pipelines generally employ centrifugal pumps driven by electric motors. The motors are predominantly in the 400-500 H.P range, although they can be larger. For instance, some lines transporting liquid products employed motors up to 1,500 H.P. at a speed of 1,780 revolutions per minute.

1.1.5 Other Engines with Possible Application to Non-Highway Transportation

Engines which have not been discussed in foregoing sections include:

- Free piston engines
- Stirling engines
- Closed cycle gas turbines

The free piston engine has been tested in shipboard operation during the 1960's, and while it had drawbacks which precluded its more general adoption, it may have properties which would make it desirable in the future, particularly since it showed some capability of running on a wide variety of fuels.

The Stirling engine and the Closed Cycle Gas Turbine have some similarity with steam engines/turbines, because they are fired externally at a heat exchanger which performs a function similar to that of the boiler. While the Stirling engine has not been used since the 19th century in practical applications, it is known to be able to use a wide variety of fuels, and has reached a high level in the development stage for engines up to 2000 HP.

The closed cycle gas turbine is a developed engine which has found application to the concurrent production of heat and power, and which runs successfully on a variety of fuels including low rank coal.

Each of these engines is described briefly in the following sections.

1.1.5.1 Free Piston Engine

A free piston engine is a combination of a gasifier with a companion gas turbine.

The basic elements of the gasifier part are:

- A pair of single-stage reciprocating compressors.
- A 2-stroke opposed piston diesel cycle cylinder, the two pistons being coupled to the compressors.
- A pair of "bounce cylinders" which convert kinetic energy of the outward flying pistons, to potential energy of compressed air. This compressed air then forces the pistons toward each other for the next cycle.

Three possible configurations are shown in diagram form on the left-hand side of Figure 1-6. C represents the compressors, D the volume between pistons which is essentially the diesel cylinder, and B the bounce cylinders.

The events of each cycle of the pistons occur as follows (refer to the right-hand side of Figure 1-6). The composite pistons are driven outward by the expanding combustion gases of the diesel cylinder and by the expanding air of the compressor-cylinder clearance volumes. Air is drawn into the compressor cylinders, and air contained within the bounce cylinders is compressed for storage of energy. Near the outer end of the stroke, first the exhaust ports and then the scavenge ports are uncovered by their respective diesel pistons, consequently releasing the combustion products to the turbine and permitting fresh high-pressure air from the scavenge system to enter and purge the cylinder. The pistons are then returned inward by the energy stored in the bounce cylinders. The ports are closed-off, the air charge thus trapped within the diesel cylinder is compressed, and the air previously drawn into the compressor cylinders is compressed and delivered to the scavenge system. Near the inner end-point of stroke, a metered quantity of fuel is injected into the diesel cylinder, causing repetition of the entire process.

The work performed by the diesel cycle is that of compressing its own combustion air, and that of overcoming friction.

Some of the fuel energy is lost to cooling water around the diesel cylinder and the net remainder flows as hot compressed gas toward the companion gas turbine. A diagram of a free piston diesel-turbine unit is shown in Figure 1-7.

The operating temperature at the turbine inlet is never above 1000°F so the materials problems are not nearly as difficult as those which have to be overcome in open cycle direct fired gas turbines, firing at 2000°F and above.

The turbine converts about 80% of the work stored in the gas to shaft work. Thus, if the gasifier converts 40% of fuel heat into work stored in gas, the overall efficiency is likely to be 32% allowing for losses at the turbine.

A comparison between the operation of the free piston engine and the open cycle gas turbine (GT) reveals why the free piston can attain such relatively high efficiency at such a low inlet temperature.

Both machines have to perform two functions:

- They must compress their own combustion air.
- They convert the energy that is left into shaft power.

In the open cycle GT, about 2/3 of the work goes into compressing the air and 1/3 is available as shaft power. The work required for compressing

FIGURE 1-6

FREE PISTON ENGINE

Source: Reference 1-15.

FIGURE 1-7

FREE PISTON DIESEL--TURBINE UNIT DIAGRAM

Source: Reference 1-15.

has to come from within the gas turbine whether it be delivered to a common shaft or to a split shaft. To get any reasonable efficiency, the inlet temperature has to be high.

In the free piston engine, the turbine is relieved of the task of compressing air. That is done by the diesel cycle and the high temperatures required are handled in the water cooled diesel cylinder where materials problems are minimal.

Thus the free piston performs the work of compression by means of an efficient diesel cycle unhampered by need to keep the working temperature low, and goes on to produce the shaft power in a gas turbine which is analogous to the later stages (the least vulnerable stages) of a direct fired gas turbine.

Its failure to compete with other prime movers up to now is largely due to maintenance problems which might be overcome or be accepted if this engine proved to be compatible with low grade fuels, assuming those same fuels were not acceptable to other prime movers.

1.1.5.2 Stirling Engines

The Stirling Engine is an external combustion, closed-cycle, piston-type power plant that uses a gaseous internal working fluid, usually hydrogen or helium. Figure 1-8 shows a simple diagram of a one-cylinder Stirling engine. The working gas, heated by an external source, flows back and forth between the cold space and the hot space. Continuous external combustion of a fuel supplies the heat through the upper wall of a cylinder. The tandem displacer and the power pistons drive two yokes that are linked to twin connecting rods, which in turn drive two output shafts in opposite directions.

One of the advantages of a Stirling engine is that it can operate on a variety of fuels, since it is an external combustion device. The disadvantages are weight and cost. For automotive application, volume and packaging are also problems, but these may not be critical in some of the non-highway transportation applications.

1.1.5.3 Closed Cycle Gas Turbine

A schematic diagram of a closed cycle gas turbine is shown in Figure 1-9.

At bottom right is an air heater (though gases other than air, such as helium can be used as the working medium). This is analogous to the boiler in a steam system and has a similar efficiency, viz 90%. The hot gas so produced is essentially at the compressor outlet pressure shown upper left.

The hot gas expands through the turbine (upper right) delivering about 32% of the net heat input as shaft work to the generator. It also drives its own compressor.

At the heat recuperator, shown in the center, much of the waste heat in the turbine exhaust gas is recovered into the gas enroute to the "boiler" (air heater).

FIGURE 1-8
STIRLING ENGINE

Source: Reference 1-17.

FIGURE 1-9

Source: Reference 1-16.

Thus, to maintain good "boiler" efficiency, the combustion air heater shown in the path of the stack gases is a very important item.

There are two water cooled heat exchangers, a precooler before the compressor, and an intercooler between compressor stages.

In the diagram, both are shown receiving cooling water at 12°C. However, if some useful purpose exists for the waste heat, some or all of the cooling water can be admitted at 40-50°C and taken out at a temperature close to 100°C. Each of the coolers shown in the diagram can yield about 25% of the input fuel heat in the form of hot water at 90-100°C.

By adjustment of the compressor inlet temperature, the ratio of shaft work to heat recovered can be varied as shown in Figure 1-10.

A small sacrifice in thermal efficiency of the work output (area A in the diagram) results in a large increase in heat available (area B). This flexibility has made a place for these engines in district heating schemes where both electricity and heat are required concurrently.

The output of the machine is varied by putting in or taking out working fluid from the cycle, in other words by adjusting the overall system pressure.

The "leakage air compressor" shown lower center in the schematic diagram, would serve to add working fluid (be it air or helium); the blow off valve, center, would serve to take it out.

In the case of helium, of course, a storage system would be provided to hold that portion of the helium inventory which was extracted for less than full power operation.

A list of working closed cycle gas turbine plants is given in Table 1-14. It will be noted that they cover a range from 2-30 MW, about 2000 to 40 000 HP.

Turbine inlet temperatures are intermediate between those of open cycle gas turbine plant, and those of the free-piston/turbine combination.

The fundamental difference is that the working gas, being heated externally, contains no combustion products nor ash residues, and the plant is tolerant to any fuel which the air heater can handle. Lignite, coal blast furnace gas and natural gas have all been used. This engine could also use nuclear heat.

As an alternative to making hot water for district heat, the waste heat might be directed to drive an organic ranking bottoming cycle to generate more work from the same heat input and raise the efficiency into the 35-40% region.

FIGURE 1-10

DIAGRAM OF THE COMBINED ENERGY AND HEAT PRODUCTION
WITH A CLOSED-CYCLE GAS TURBINE PLANT

A Net output (thermal efficiency)	D Mechanical and electrical losses
B Heating water	E Losses of auxiliary machines
A + B Total energy efficiency	F Unaccountable losses
C Cooling water loss	G Air heater losses

Source: Reference 1-16.

TABLE 1-14

LIST OF SOME CONVENTIONAL CLOSED-CYCLE GAS TURBINE PLANTS

Plant	Ravensburg Germany	Toyotomi Japan	Coburg Germany	Kashira Russia	Nippon Kokan Japan	Oberhausen Germany	Haus Aden Germany	Geisen- Kirchen	Dye Oxidant Phoenix, Austria	Spittsiau, Vienna Austria
Manufacturer	EW Ltd. + GHH Ltd.	Fuji Electric EW Ltd.	GHH Ltd.	EW Ltd.	Fuji Electric	GHH Ltd.	GHH Ltd.	GHH Ltd.	EW Ltd. + LF Corp.	EW + Wagened Bisco
Use	Power + Heat	Power	Power + Heat	Power + Heat	Power	Power + Heat	Power + Heat + Turbo-Com- pressor drive	Power + Heat	Cryogenic	Power + Heat
Fuel	Bituminous Coal	Natural Gas	Bituminous Coal	Brown Coal	Blast Furnace Gas	Bituminous Coal	Mine Gas and Bituminous Coal	Blast Furnace Gas and Oil	Natural Gas	Oil or Gas
Operating Data:										
Continuous output	kW 2 300	2 000	6 600	12 000	12 000	14 300	6 370	17 250	—	30' 000/22 000
Temperature at compressor inlet	°C 20	20	20	20	25	30	20	20	20	20/60
Pressure at compressor inlet	ata 7.2	7.2	7.3	7	6.7	8	9.3	10.2	—	—
Temperature at turbine inlet	°C 660	660	680	680	680	710	680	711	680	720
Pressure at turbine inlet	ata 27	27	27.5	29	29	32	31	38.5	—	44
Plant efficiency at generator terminals	% 25	26	28	28	29	29.5	29.5	30	—	31/24
Compressor and turbine speed	r.p.m. 12 750	13 000	8 220	6 600	6 600	6 600	8 220	6 640	18 000	6 500
Generator speed	r.p.m. 3 000	3 000	3 000	3 000	3 000	3 000	1 500	3 000	—	3 000
Heating water:										
Quantity	m ³ /h 70	—	110	280	—	325	130	200	—	—
Temperature at cooler outlet	°C 75	—	100	75	—	90	90	95	—	110
Temperature at cooler inlet	°C 45	—	40	45	—	40	40	40	—	50
Amount of heat	Gcal/h 2.1-3.5	—	7-14	8-10	—	16-24	6.7	16.9	—	29/50
Design Characteristics:										
Compressor:										
Type	radial	radial	axial and radial	axial	axial	axial	axial	axial	axial	axial
Turbine:										
Type	axial	axial	axial	axial	axial	axial	axial	axial	axial	axial
In operation since:	1956	1957	1961	1967	End of 1961	1960	1963	starting 1967	starting 1966	starting 1972
Running hours up to December 1970:	83,000	85,000	64,000	46,000	85,000	70,000	58,000	18,000	75,000	—

EW Ltd.: Escher Wyss Ltd. Zurich (Switzerland), GHH Ltd.: Gutehoffnungshütte Sterkrade Ltd., Oberhausen-Sterkrade (Germany), Fuji Electric Kawasaki (Japan), LF: The Le Fluor Corporation, Torrance, Calif., USA.

Source: Reference 1-16.

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2. CRITERIA TO BE USED TO EVALUATE AND RATE FUELS AND PRIME MOVERS

E. N. Cart, Jr.

In the preliminary screening phase of the study on alternate fuels for non-highway transportation, a method was used that allowed one to evaluate fuels and energy sources in a sound, logical and technical manner, and to select several fuels/prime movers for more indepth analysis. In the preliminary screening, the main emphasis was on the fuels/prime mover/user interactions and it was assumed that technology was available to produce and use the fuels. Technology is defined in this instance as the know-how required to produce the various products. It does not include the actual commercialization of the process.

The factors that were considered in the preliminary screening are as follows:

Fuel Manufacture

1. Cost of production, distribution and storage
2. Overall energy efficiency up to point of use
3. Environmental impact in production

Fuel Performance from Designer/User Viewpoint

4. Toxicity
5. Safety
6. Materials Compatibility
7. Potential type of prime mover that could use a given fuel
8. Storage on vehicle
9. Convenience in handling and storage
10. Environmental impact during use

Fuel Logistics

11. Resource availability
12. Compatibility with present fuel
13. Compatibility with current distribution system
14. International considerations

The general procedure that was used for the rating in each of these three areas is discussed in the following sections.

2.1 Fuel Manufacture Criteria

In the fuel manufacture criteria area, it was necessary to consider the various raw material or energy sources for some of the fuels such as for methanol, hydrogen, etc.

The economics cover the cost of production, distribution and cost to liquefy the fuel, in the case of hydrogen and methane, expressed on a dollars per million BTU basis. All of the costs are on a common, consistent basis.

The overall system efficiency for the production of the resource, manufacture and distribution is the second item considered. This is expressed as the BTU's of energy in the basic resource, such as coal, that would be required to produce a BTU of energy in the fuel at the point of use. The fuel with the lowest value would be the most efficient one to use.

The environmental impact in production considered air pollutants (SO_x , NO_x , CO, particulates, etc.), water pollutants, and solid waste.

Since the overall rating will be composed of several dissimilar indices, it is planned to use a Likert scale for rating each category.* It will then be possible to arrive at an overall rating by combining each category (cost, energy efficiency, environment impact), assuming an equal weighting of all three factors. A different weighting factor could also be used.

2.2 Fuel Performance Criteria from Designer/User Viewpoint

There are many factors to be considered in evaluating the various fuels from a performance standpoint. The factors that were used in the screening of the various fuels are shown below.

- Toxicity
- Safety
- Materials Compatibility
- Storage Requirements
- Convenience in Handling and Storage
- Environmental Impact During Use

For this particular category, it is not necessary to consider the various raw material sources for producing each fuel. For example, it is only necessary to consider how hydrogen would perform, since the hydrogen would have the same properties whether it was produced from coal, nuclear (electric) power, or solar energy. In considering each fuel under this criteria, the designer's and user's viewpoints are the major considerations.

*The Likert scale is described in Section 13.

The rating system to be used for toxicity will be low, medium or high toxicity, based on the detailed data that are presented in the physical property data section. The current petroleum specification will serve as a reference point for determining the degree of toxicity.

The physical property data from Section 3 were used to arrive at a rating of a low, medium or high safety hazard for the composite safety rating. The current petroleum fuel will serve as a reference point.

The materials compatibility will have a rating of satisfactory, borderline, and not suitable, based on the current engine design practices. It is very likely that with most of the fuels, very little data may be available, indicating this is an area for future research, if a particular fuel shows promise in the other categories.

In evaluating the performance potential for each fuel, it was necessary to consider the compatibility of the fuel and various prime movers. A table was prepared showing how the various fuels may operate in a given type of prime mover. It is well beyond the scope of this study to make any detailed engineering studies to design a prime mover for each fuel. However, estimates were made on how each fuel may operate in the current designs based on literature data on how fuels have performed in such an engine or based on the combustion properties of each fuel. It is recognized that an entirely different type of engine could possibly be designed for the 2000+ period, but for the preliminary screening it will be assumed that the fuels should be compatible with current designs. The numerical compatibility rating that will be used is defined as follows:

- 4 = No modifications required; could be used in current designs
- 3 = Minor modifications required
- 2 = Major modifications required
- 1 = Not practical; would require an entirely new design

There are several other energy sources/prime mover combinations that were considered. These include the fuel cell, nuclear propulsion power, electric power and solar thermal and solar photovoltaic. Each of these forms of energy systems were evaluated separately since in each case it was necessary to consider the mode of transportation in addition to the manufacture, performance and logistics factors.

The next performance factor that was considered is the storage requirements of the fuel on board the vehicle. A base quantity of fuel will be assumed required, based on current storage capacity. Admittedly this does not account for improved efficiency that may be possible with some fuels in a particular prime mover.

An important performance factor to consider from the user's viewpoint is the difficulty or ease of handling and storing fuels at the consumer's point of use. The physical property data shown in Section 3 was be used to arrive at an overall rating of excellent, good, fair, poor or unsatisfactory for each fuel.

In considering the environmental impact during use, it is really necessary to evaluate each fuel-prime mover combination and to consider the mode of transportation. However, for the preliminary screening, only emissions for the diesel and gas turbine engines, the major type of prime movers used in non-highway transportation were considered and the consideration of where the emissions occur--at high altitudes, near populated centers, or on the open seas was neglected. Only air pollutants were considered, and the detailed emission rates were summarized into an excellent, good, fair, poor rating.

The overall rating for the performance criteria is a combination of all seven factors, assuming an equal weighting.

2.3 Fuel Logistics Criteria

The third major area considered was the impact of the various fuels on the logistics of supply. For this category, it was necessary to consider the source of the raw material for producing the various fuels, since this can have a bearing on the overall rating. For example, methanol from coal may be an attractive option, but methanol from biomass may not be attractive due to resource availability. The factors that were considered from the logistical standpoint are as follows:

- Resource availability
- Compatibility with present fuel
- Compatibility with current distribution system
- International and military considerations

Two factors that were considered are compatibility with the present fuel and with the current distribution system. These are critical issues from a practical standpoint. While incompatibility of a given fuel would not eliminate it from further consideration, it would require consideration of how such a fuel would be introduced. Production, distribution and equipment user are all interdependent, in that one is not likely to occur without the other two. Different kinds of decision-makers would have to make coordinated decisions for a smooth development to occur and any one kind of decision-maker can "veto" the development.

Air and marine operations involve international fueling and any new fuel should be available in the countries involved. This would require local production capability, which in turn would generally be dependent on suitable local resources. Another international factor considered was the export market for equipment using any new type of fuel or prime mover.

Resource availability may determine whether some raw materials or energy sources should be considered for non-highway transportation use. In the preliminary screening, it is shown whether a given energy source will be adequate, probably adequate, probably inadequate or inadequate to produce the fuels.

All four factors were combined into an overall logistics rating.

2.4 Overall Rating

The final rating is a combination of the three separate areas. All factors were given equal weight. Based on the overall ratings, the fuels and prime mover for in-depth analysis were selected. All three factors were considered as separate, non-interacting criteria, and were given equal weight to arrive at an overall rating.

In practice these criteria are not separable because they interact. For example, if a fuel or prime mover is "unsatisfactory" in any one criteria, it would likely mean that fuel or prime mover would not be used, unless the technology was improved to overcome the deficiencies or the institutional problems were solved. This will also serve to identify what R&D is needed to make a given fuel attractive. The problem is how to combine the various criteria ratings in an interactive case.

3. PHYSICAL AND CHEMICAL PROPERTIES OF ALTERNATE FUELS

W. Herbst

Experience has shown that many physical and chemical properties of a fuel influence its performance in the engine, acceptability to the user, impact on the environment, and methods of handling and distribution.

The ideal fuel should permit easy equipment starting at ambient temperatures, give rapid warm-up and acceleration, provide trouble-free operation, have good fuel economy and adequate periods between refuelings, keep engine and equipment maintenance to a minimum, not be unduly hazardous and, or course, be economically attractive. Neither the fuel nor the exhaust should have an objectionable odor. Environmental impact involves fuel emissions encountered in handling, storage, and refueling, as well as the nature and composition of the exhaust emissions. Storage and handling considerations also require that large volumes of the fuel be contained without serious deterioration or loss for periods up to six months or longer, be moved through pipes and/or in tankers, barges and tank trucks, and be dispensed and metered to the user. This must be done safely, without serious environmental damage and without significant contamination with water, rust or dirt.

A discussion of the significance of various fuel properties is given in Appendix 3-1. It is evident that the properties of the fuel have an impact on many important criteria. The interrelationships are summarized in Table 3.1, which serves as the general basis for categorizing the property data collected in this study. Tables 3-2 to 3-7 list fuel properties related to combustion behavior, handling, storage, and engine maintenance. These tables show properties for the fuels considered in this study and also give typical values for petroleum fuels for comparison. In quite a few instances, where data were not available, estimates were made, identified by parentheses around the value. In the case of the coal and shale liquids, the properties shown are for products produced from syncrudes by currently available refining methods. The properties of the fuels from shale and coal will vary with the syncrude characteristics and method of refining. This makes it extremely difficult to place all the available data within a convenient, standardized format. Accordingly, considerable additional information on various coal and shale liquids are presented in the appendices as discrete studies on specific syncrudes by specific refining operations.

3.1 Combustion Properties

A number of significant observations can be made regarding the combustion properties of the fuels shown in Table 3-2.

- The low boiling points of hydrogen, methane, ammonia, methylamine and acetylene indicate that special equipment will be required to store and handle these materials. Storage could be either as

TABLE 3-1
RELATION OF FUEL PROPERTIES AND FUNCTIONS

	<u>Distribution</u>	<u>Storage (Bulk and on Vehicle)</u>	<u>Environmental Impact</u>	<u>Safety</u>	<u>Compatibility with Pet. Fuels</u>	<u>Prime Mover Performance</u>					
						<u>Diesel</u>	<u>Gas Turbine</u>	<u>S.I. Internal Comb.</u>	<u>Fuel Cell</u>	<u>Stirling</u>	<u>Steam Boiler</u>
Volatility											
Initial Boil Pt			H	H			H	H		M	M
50% Pt					M	H	M	H			
90% Pt						H	M	M		M	M
Final Boil Pt						H	M	H		M	M
Heat of Vaporization								M			
Heat of Combustion, BTU/lb						H	H	H	H	H	H
Cetane No.						H					
Luminometer Rating							H				
Smoke Point							H				
Octane No.								H			
Viscosity @ 100°F					M	H	H		M	M	M
Flame Speed						M	M	M		M	M
Flammability Limits	M	H		H	M	M	M	M		M	M
Vapor Pressure	H	H	H	H	H	H	H	H		H	H
Density	M	H			M						
Pour Pt	M	M			M	H	H	H	H	H	H
Freezing Pt	M	M			M	H	H	H	H	H	H
Toxicity	H	H	H	H	H						
Flash Pt	H	H		H	M						
Fuel Odor	M	M	M	M	M						

Code: H = highly important; M = moderately important; Blank = not important to function.

TABLE 3-1 (CONTINUED)

	<u>Distribution</u>	<u>Storage (Bulk and on Vehicle)</u>	<u>Environmental Impact</u>	<u>Safety</u>	<u>Compatibility with Pet. Fuels</u>	<u>Prime Mover Performance</u>					
						<u>Diesel</u>	<u>Gas Turbine</u>	<u>S.I. Internal Comb.</u>	<u>Fuel Cell</u>	<u>Stirling</u>	<u>Steam Boiler</u>
Effect on Plastics	M	M				H	H	H	H	H	H
Viscosity @ 0°F	M	M			M		M				
Viscosity @ -30°F							M				
Solubility in Water	M	M			M	M	M	M	M	M	M
Solubility for Water	M	M			H	M	M	M	M	M	M
Emulsion Tendency	M	M			M	M	M	M	M	M	M
Storage Stability	M	H			M	M	M	M	M	M	M
Lubricity	M					M	M		M	M	M
Static Charge	H	M		H	H		M				
Sulfur			H		M	M		M	H		
Corrosivity	M	M		M	H	H	H	H	H	H	H
Nitrogen			H		H		H		H		
Ash			H		M	H	H	H	H	M	M
Sodium						M	H		H	M	M
Vanadium						M	H		H	M	M

Code--H = Highly important

M = Moderately important

Blank = Not important to the particular function.

TABLE 3-2

FUEL CHARACTERISTICS RELATED TO COMBUSTION BEHAVIOR

Fuel	Heat of Combustion (Net)		Heat of Vap-BTU/lb @ Normal Boil Pt	Volatility (Boiling Pt)-°F				Vapor Pressure @ 100°F psi
	BTU/lb	BTU/Gal		Initial	50%	90%	Final	
Petroleum								
- Gasoline	18,700	114,000	(150)	100	210	330	400	8-12
- Jet Fuel (JP 4)	18,600	124,000	(110)	--	370	470	--	(2)
- Distillate	18,400	129,400	(100)	375	500	580	620	0.01
Coal	12,000-15,000	--	--	--	--	--	--	--
Coal/Methanol Slurry (40/60) (e)	10,000-11,200	(68,000)	--	149	149	--	--	(4)
Coal/Oil Slurry (40/60) (e)	15,800-17,000	(140,000-150,000)	--	--	--	--	--	(0.01)
Coal Liquids (c)								
- Jet Fuel (JP-4)	18,400-18,500	(123,000-124,000)	(110)	190	306	380	427	(2)
- Diesel	(18,300)	(130,000)	(100)	300	--	--	550	(0.01)
- Fuel Oil	(17,400)	(140,000)	(70)	--	580	780	--	(<0.01)
Shale Oil Liquids								
- Raw	(18,200)	(134,400)	(75)	(100)	(750)	>1000	>1000	(4)
- Syncrude	(18,500)	(122,700)	(105)	--	(450)	(750)	(850)	8
Methanol	8,640	57,370	474	--	149	--	--	4.6
Hydrogen	51,600	30,600	194	--	-423	--	--	(d)
Ammonia	8,060	31,000	591	--	-28	--	--	212
Oxygenated Compound								
- Ethanol	11,550	76,000	360	--	173	--	--	0.28(b)
- Higher Alcohols	(11,600)	(76,100)	(350)	150	--	--	300	--
Methane	21,500	80,000	219	--	-259	--	--	(d)
Hydrazine	7,294	61,000	540	--	236	--	--	0.28(a)
Methylamine	12,860	74,983	376	--	21	--	--	--
Acetylene	20,780	--	323	--	-119	--	--	(d)
Vegetable Oil (Cotton Seed)	16,600	(128,000)	--	--	--	--	--	--

(a) At 77°F; (b) At 68°F; (c) Assumes treatment by known technology to meet current product specifications; (d) Above critical temperature; (e) Weight percent coal/methanol or coal/oil; () Denotes estimated value.

TABLE 3-2 (CONTINUED)

Fuel	Stoichiometric Mix		Octane Number (Zero Lead)		Cetane Number	Auto Ignition Temperature °F	Max. Flame/ Speed-Ft/SEC	Flammability Limits - Vol %		Kinematic Vis. 77°F, cs	References
	Lb Air/ Lb Fuel	BTU/ft ³ (STP)	RON	MON				Upper	Lower		
Petroleum											
- Gasoline	(14.8)	100	86-93	77-84	(0-5)	800-950	(1.1)	8	1.0	0.5	3-1
- Jet Fuel (JP-4)	(14.7)	101	--	--	(40)	470-490	(1.1)	5	0.7	(2)	3-1
- Distillate	(14.5)	102	--	--	48	500	(1.1)			3.0	3-1,3-2
Coal	(10.3-12.5)	(94-97)	--	--	--	1100				50 oz/ 1000 ft ³	3-3
Coal/Methanol Slurry (40/60)(e)	(8.5)	(95)	--	--		(880)		(37)	(6)		
Coal/Oil Slurry (40/60)(e)	(13.3)	100	--	--		500		--	--	1400-2200	3-4
Coal Liquids(c)											
- Jet Fuel (JP-4)	(14.5)	(102)	--	--		480-490	(1.1)			(2)	3-2,3-5
- Diesel	(14.3)	(103)	--	--	(40)	(480)	(1.1)			(3)	3-6
- Fuel Oil	(14.0)	(100)	--	--	28	(470)	(1.1)			(8)	3-7
Shale Oil Liquids											
- Raw	(13.8)	(106)					(1.1)			25	3-8
- Syncrude	(14.1)	(106)					(1.1)			4.3	3-8
Methanol	6.5	95	106	92	(10)	878	1.6	37	6.0	0.64	3-1
Hydrogen	34.6	85.2				1085	8.7	74	4.1		3-1
Ammonia	6.1	83.5	130		<0	1204	0.034	25	16		3-1
Oxygenated Compounds											
- Ethanol	9.0	97	106	89	(15)	738		19	3.5	1.39	3-1
- Higher Alcohols			(105)	(90)	(15)						3-1
Methane	17.3	90.9	130	105	<0	1004	1.12	15	5.0		3-1
Hydrazine	4.3	104				520		100	4.7	0.89	3-1
Methylamine	11.9	87.5				806		21	4.9		
Acetylene	13.3	126				581		80	2.8		3-9
Vegetable Oil (Cotton Seed)	13.0	103	--	--		530				36.7 @ 100°F	3-10

(a) At 77°F; (b) At 68°F; (c) Assumes treatment by known technology to meet current product specifications; (d) Above critical temperature;
(e) Weight percent coal/methanol or coal/oil; () Denotes estimated value.

cryogenic liquids or pressurized gases. In either case, there may be problems in adapting these fuels to certain applications, as discussed further below.

- The relatively low volumetric heat of combustion (BTU/gal) of the alcohols, hydrazine, ammonia, methylamines, methane (ℓ) and hydrogen (ℓ) is a significant disadvantage in that it will require the storage of relatively large volumes of these fuels for a given period of operation.
- The relatively high heat of vaporization of the alcohols, hydrazine, liquid ammonia, liquid methane, and liquid hydrogen, combined with their low heat content, means that with a carburetted engine, special pains must be taken to transfer adequate heat to the intake manifold to vaporize the fuel. For example, it takes eight times as much heat to provide the same amount of combustion energy in the vapor form with ammonia as with a conventional gasoline. This is usually waste heat from the engine (in exhaust or water) and represents no thermal penalty to the engine. This heat exchange problem can be avoided by injecting the liquid fuel directly into the combustion chamber as is possible with diesel, gas turbine or similar injected engines.
- The BTU/ft^3 of a stoichiometric fuel/air mixture relates to the amount of energy that can be inducted into the combustion chamber of a carburetted reciprocating piston engine of a given displacement. The higher this figure, the more power can be produced from a given displacement carburetted engine at a given engine speed. This assumes that each fuel is being burned with an amount of air theoretically required for complete combustion.
- The high octane numbers of ammonia, methane, and methanol are noteworthy. With such fuels it should be possible to design an Otto cycle engine (high compression ratio) that would have a higher thermal efficiency than would be possible with the lower octane number fuels. However, this point will have to be demonstrated with ammonia and methanol, in view of the uncertainty in translating experience based on high octane hydrocarbon fuels to widely different compounds.
- Apparently the combustion characteristics of hydrogen are such as to make a rating by the accepted anti-knock methods difficult since no octane numbers have been published. Single-cylinder engine combustion studies have indicated, (3-11) however, that hydrogen can be burned in an Otto cycle engine without knock over a compression ratio range from 6:1 to 16:1 by careful adjustment of spark advance and air/fuel ratio. At a given compression ratio, say 8:1, combustion behavior varies as the amount of hydrogen in the air is increased. For example, a mixture containing less than 0.73 wt% hydrogen is too lean to burn and mixfire results. Between 0.73 and 1.5 wt% hydrogen, satisfactory knock-free operation is achieved. As the amount of hydrogen is increased above 1.5 wt% knock is encountered and continues until the hydrogen reaches 16 wt%. From here to the upper flammability limit

(25 wt%) knock-free operation is again experienced. It should be noted that above a hydrogen concentration of 2.81 wt% (stoichiometric mixture) hydrogen combustion will be incomplete because of insufficient air. Thus, the feasible knock-free fuel/air operating range at 8:1 compression ratio, according to these data, is in the range of 0.73 to 1.5 wt%. At 16:1 compression ratio, this knock-free "operating window" ranges from 0.75 to 1.0 wt% hydrogen. Evidently, it will require closer fuel/air ratio control to operate knock-free with hydrogen at high compression ratios than at low. However, there is some question about the validity of these results since knock-free operation over a wide range of fuel/air ratio has also been reported.(3-12,3-13) Problems of preignition(3-14) and backfire(3-15) with hydrogen have also been reported. Exhaust gas recycle has been used to modify and control the combustion of hydrogen in an Otto cycle engine.(3-16)

- The Cetane Number of all the fuels in Table 3-2, except for the distillates from petroleum, shale, and coal, are too low to make them attractive as fuels for an engine operating on the compression ignition principle. The use of cetane-improving additives, supplementary sources of ignition (e.g., a glow plug, pilot-injection, or spark plug), blends with high-cetane number fractions, or the use of high compression ratios (say 22:1) are alternative ways by which this quality deficiency might be overcome.
- The high flame speed of hydrogen and the low flame speed of ammonia are noteworthy. They imply that the optimum engine operating conditions or design for these fuels will be different than for the more conventional hydrocarbon fuels.
- The exceptionally wide flammability limits of hydrogen are significant. This is the basis of the "Hydrogen Induction Technique(3-12,3-13) method of engine (Otto cycle) operation in which the engine power is varied by varying hydrogen-air ratio and not by throttling the fuel/air mixture. In the Hydrogen Induction Technique the amount of air taken into the combustion chamber on each piston stroke is held constant (no air throttling) while the amount of hydrogen inducted is increased for increased power. Higher efficiency is claimed for this method of operation.(3-12) Unfortunately, the wide flammability limits adds to the hazard of using hydrogen as a fuel.

3.2 Vehicular Storage Requirements of Fuels

The low boiling points of ammonia, methane, hydrogen, and acetylene present a problem with regard to the storage of these fuels. For acetylene it would be necessary to store the acetylene in acetone or use calcium carbide to directly generate acetylene. The magnitudes of the storage problem for each of the fuels being considered are summarized in Table 3-3. In comparing the weight advantage or disadvantage for each fuel, the table shows a ratio of the weight of fuel required to provide the same BTU output as a pound of petroleum distillate. For example, 2.13 pounds of methanol would be required to provide the same energy as a pound of petroleum distillate. The fuels that show a

TABLE 3-3

STORAGE REQUIREMENTS OF FUELS

	Weight	Volume
	Lbs. Fuel/Lb. of Petroleum Distillate for Same BTU Output	Vol. Fuel/Vol. of Petroleum Distillate for Same BTU Output
Petroleum--Jet	0.99	1.04
--Distillate	1.0	1.0
Coal	1.23-1.53	1.2
Coal/Methanol Slurry	1.64-1.84	1.9
Coal/Oil Slurry	1.08-1.16	0.86-0.92
Coal Liquids--Jet	0.99-1	1.04-1.05
--Diesel	1.01	1.0
--Fuel Oil	1.06	0.92
Shale Oil--Raw	1.01	0.96
--Syncrude	0.99	1.05
Methanol	2.13	2.26
Hydrogen (l)	0.36	4.23
Ammonia	2.28	4.17
Ethanol	1.59	1.7
Higher Alcohols	1.59	1.7
Methane (l)	0.86	1.62
Hydrazine	2.52	2.12
Methylamine	1.43	1.73
Acetylene(1)	4.1	--
Vegetable Oil	1.11	1.01

(1) Includes weight of calcium carbide and water needed to generate the acetylene.

major weight disadvantage (>1.5 ratio) are coal/methanol slurry, some coals, methanol, ethanol, ammonia and hydrazine. The data for liquid hydrogen shows why it is of interest as an aircraft fuel, where weight is critical. Liquid methane has a slight advantage over petroleum distillate.

While the comparison of the weight ratio for fuel only is a good basis for most fuels, it is not valid for liquid hydrogen, liquid methane or liquid ammonia. For these fuels, the weight of the container must also be considered. A direct comparison will depend on the specific mode of transportation. However, based on previous studies for storage of fuels in automotive application including the weight of the container can increase the ratio to 2.6 for liquid hydrogen, 1.78 for liquid methane and 3.4 for ammonia. (3-1)

The volume required to store a given fuel is compared to petroleum distillate as a ratio of the storage volume required to provide the same BTU output as a given volume of petroleum distillate. The fuels that would require substantially more space to store a given amount of fuel are methanol, liquid hydrogen, ammonia, ethanol, liquid methane, and hydrazine. If the volume of the container is also considered, the ratio would be essentially the same, except for liquid methane and liquid ammonia, where a larger volume would be required than for just the fuel alone. (3-1)

The practicability of using hydrogen in vehicular applications, and to a lesser extent, methane, acetylene, and methylamine, will depend on solving the storage problems. Storage as a cryogenic liquid is possible, but increases the cost of the storage container, and could create other problems, e.g., fuel losses due to evaporation, and the requirement for safe venting provisions from the fuel storage enclosure.

3.3 Bulk Handling and Storage of Fuels

Table 3-4 lists the characteristics related to the handling and bulk storage of the fuels. Following are some observations regarding this table:

1. The high freezing point of hydrazine (36°F) and vegetable oils (26°F) indicates that special means would be required to keep them liquid in storage tanks in many areas of the United States at various times of the year. One solution to the hydrazine problem may be to use it mixed with unsymmetrical dimethyl hydrazines (freezing point ca. -71°F).
2. The water miscibility of hydrazine, methylamine, methyl alcohol and ethyl alcohol indicates that the storage and transportation system handling these fuels would have to be kept dry, to avoid problems such as fuel instability, corrosion, etc., which could affect performance.
3. Storage stability of coal slurries would be expected to be troublesome because of settling of the solid coal from the liquid. Close control of coal particle size will be necessary. The use of stabilizing agents might be helpful. Some means of continuous mixing may be required.

TABLE 3-4

CONVENIENCE IN HANDLING AND STORING VARIOUS ALTERNATE FUELS^(j)

Fuel	Vapor Pressure psi @ 100°F	Density lbs/ft ³ @ 60°F	Viscosity Kin cs @ 0°F	Freezing or Pour Point °F	Flash Point, °F (Closed Cup)	Sol. in Water @ 68°F Wt%	Sol. for Water @ 68°F ppm	Emulsion Tendency	Storage Stability	Effects on Metals	Toxicity Dangerous for Prolonged Exposure, PPM	References
Petroleum												
- Gasoline	8-12	(46)	(1.0)	(-40)	-30	N11		NP(m)	NP(m)	NP(m)	500	3-1,3-9
- Broadcut	1-5	(49)	(2.5)	(-30)	-30	N11		NP(m)	NP(m)	NP(m)	500	
Coal		42-57(k)	--	--		N11					Non-toxic	(e),3-9
Coal/Methanol Slurry	(4.6)	(57)			(50)(g)						200	
Coal/Oil Slurry	(<0.1)	(62)	>1400		(>130)	N11						
Coal Liquids												
- Jet Fuel (JP-4)	2	(51)	(2.5)	-90		N11				NP(m)		3-18
- Diesel	(0.01)	(53)	(4.5)	(-20+5)		N11				NP(m)	(500)	3-18
- Fuel Oil	(<0.01)	(59)	(>8.0)			N11				NP(m)	(500)	3-18
Shale Oil Liquids												
- Raw	(4)	(55)	(>25)	75		N11				NP(m)	(500)	3-8
- Syncrude	8	(50)	(>45)	50		N11				NP(m)	(500)	3-8
Methanol	4.6	49.7		-142	52(g)	Infinite	Infinite				200	3-1,3-9
Hydrogen	(n)	4.43(c)		-435	--			NP	NP		Asphixiant	3-1,3-9
Ammonia	212	48.1(c)		-108	--	33.1		NP		(h)	100	3-1,3-9
Oxygenated Compound												
- Ethanol	0.28(a)	49.3		-179	65(g)	Infinite	Infinite				1000	3-1,3-9
- Higher Alcohols	(0.3)(a)	(49.5)		(-170)	>65(g)						1000	3-1,3-9
Methane	(n)	27.9(c)		-296	--			NP	NP		Asphixiant	3-1,3-9
Hydrazine	0.28(b)	62.6	1.2(d)	35.6	126(g)	Infinite	Infinite		NP	(i)	1	3-1,3-9
Methylamine		41.4(c)		-136		Very					10	3-9
Acetylene	(n)			-115				NP			Asphixiant	3-9
Vegetable Oil (Cotton Seed)	(<0.1)	57(f)	36.8(f)	26	275							3-24

See next page for footnotes.

FOOTNOTES TO TABLE 3-4

- (a) At 68°F.
 - (b) At 77°F.
 - (c) At normal boiling point.
 - (d) At 41°F.
 - (e) Chemical Engineers Handbook, Perry and Chilton.
 - (f) At 100°F.
 - (g) Open Cup.
 - (h) Corrodes copper, brass and zinc.
 - (i) Materials to be avoided include cobalt, copper, pure iron, lead, manganese, magnesium, tin and zinc.
 - (j) Code: NP - no problem.
 - (k) Broken.
 - (m) Can be controlled by careful refining and use of additives.
 - (n) Above critical temperature.
-)

4. The danger from explosions or fires set by static electric discharges generated in the handling of hydrogen, methane and ammonia is understood to be low. Static electric generation is a maximum with materials whose conductivities are in the range of 10^{14} - 10^{18} ohm centimeters. The conductivities of liquid methane and liquid hydrogen are below this range. The conductivity of liquid ammonia is above this range.
5. It will probably be more hazardous to handle ammonia, methylamine and hydrazine than petroleum fuels. The primary hazard with ammonia is from inhalation. With hydrazine, both inhalation and skin contact must be avoided. With liquefied ammonia, hydrogen, and methane, skin contact with the cold liquids must obviously be avoided.
6. The indications are that the coal liquids will probably contain a high concentration of aromatic hydrocarbons. It appears also that the benzene content of the naphthas may be appreciably higher than those from petroleum sources (1-5 vol%). In view of the toxic nature of benzene, the unblended coal gasolines may require more careful handling than current petroleum gasolines. Information on toxicity of the fuels being screened is given in Section 3.5.
7. Ammonia and hydrazine are apparently the most corrosive fuels. Ammonia is corrosive to materials containing copper, brass and zinc. Methylamine would be expected to resemble ammonia. Hydrazine is corrosive to cobalt, copper, pure iron, lead, manganese, magnesium, tin and zinc. Corrosion due to the introduction of water into the fuel handling and storage system is also a potential problem. Hydrazine decomposition is also catalyzed by various metal contaminants.
8. Hydrogen can cause metal embrittlement at elevated pressures even at ambient temperatures. (3-1) This must be considered in designing systems for distributing and storing hydrogen.
9. Table 3-5 summarizes information on fuel compatibility with various elastomers and plastics which might be used. There is by now a good deal of industrial experience in handling liquid hydrogen, methane, ammonia and acetylene. This experience can serve as a suitable starting point for selecting materials of construction for fuel systems to handle these compounds. However, stringent performance requirements centered around long-time, safe, and trouble-free operation, may impose new limitations on material selection. For example, the low viscosity and high diffusivity of gaseous hydrogen will make it extremely difficult to contain in equipment having any non-metallic parts.

A number of polymeric materials seem to have good resistance to the alcohols, e.g., chlorosulfonated polyethylene, butyl rubber, polydimethyl silicone with vinyl crosslinks, etc. There are no data on the effect of coal liquids on the various elastomers. A plastic resistant to the aromatic hydrocarbons is vinylidene fluoride-hexafluoro-propylene copolymer (Viton). Fluorosilicone rubber may also be a possibility.

TABLE 3-5

**EFFECT OF POTENTIAL AUTOMOTIVE FUELS
ON VARIOUS ELASTOMERS AND PLASTICS**

Fuel	Swell, Vol % (a) (c)															
	CST	FVSi	EPM	EPDM	NR	CSM	EU	ECO	SBR	IIR	NBR	ACM	FPM	VSi	CR	PTFE
Hydrogen, (g)																
Hydrogen (l)																
Methane (g)																
Methane (l)																
Ammonia (g)																
Ammonia (l)																
Hydrazine (l)																
Methanol	15	8				0		27	2	-2	18	140	68	0		8
Ethanol			-1	-4	4	6	75	25		5	21		13	5		
Coal-Gasoline(b)																
Coal-Distillate(b)																
Shale-Gasoline																
Shale-Distillate																
Benzene	113	23		103	190	S		198	180	92	155	214	10	70	168	
Toluene	37		218	150	187	188	138	163	157	87	144		5	83	171	
Hexane			178	93	125	24			53	51	27			108	21	

(a) Suitability criteria:

- Not suitable - swell above 25%
- Borderline - swell between 15-25%
- Satisfactory - swell below 15%
- S - material softened excessively

(b) Data on benzene and toluene may be taken as a guide to behavior of these highly aromatic hydrocarbon mixtures.

(c) Code:

CST - polysulfide rubber	SBR - styrene-butadiene rubber, GR-S
FVSi - fluorosilicone rubber	IIR - isobutene-isoprene rubber; Butyl rubber
EPM - ethylene-propylene rubber	NBR - nitrile-butadiene rubber
EPDM - ethylene-propylene terpolymer	ACM - polyacrylate-acrylic acid copolymer
NR - natural rubber; polyisoprene, hevia	FPM - vinylidene fluoride-hexafluoropropylene copolymer (Vitan)
CSM - chlorosulfonated polyethylene	VSi - polydimethyl silicone with vinyl crosslinks
EU - urethane rubber	CR - polychloroprene (Neoprene)
ECO - epoxychlorohydrin rubber	PTFE - polytetrafluoroethylene (Teflon)

Blank spaces mean that data were not available.

3.4 Engine Maintenance

Table 3-6 lists the fuel properties that relate to engine maintenance requirements. The fly ash content of the coal will be particularly troublesome in many applications.

The sludge tendency listed in the table refers to crankcase sludging in reciprocating piston engines. This usually arises because of unburned or partially burned high boiling fuel components which reach the crankcase by slipping by the piston rings. Shale and coal liquids would be expected to be quite similar to petroleum-derived fuels in this regard. However, this remains to be confirmed by long-term engine tests. The combustion products of hydrogen and methane would be expected to be rather innocuous as far as crankcase conditions are concerned. However, the fuels rich in nitrogen, i.e., ammonia, hydrazine, and methylamine, might have bad effects because of reactive oxidation products (e.g., NO_x) and incompatibility with the crankcase lubricants (e.g., reaction with lubricant additives).

The question of lubricant compatibility is also of concern with the alcohols. The unburned fuel or oxidation products and the lubricating oil may form two phases in the crankcase, causing precipitation of the lubricant additives, or have other unexpected effects. These questions also can only be answered by long-term engine tests.

3.5 Toxicity

In judging the feasibility of alternative fuels, matters of toxicity and associated health hazards must be examined by the manufacturer and marketer for the potential impact upon employees, consumers, and the public at large. The following is a brief overview of these considerations for several fuels. In the absence of detailed specifications and composition data, it may turn out that additives or contaminants (trace or otherwise) are likely to be of toxicological significance. Product types, where this assumption is of critical importance, is noted. For each fuel, a summary of toxicity information and a statement of risk is presented.

3.5.1 Gasolines from Coal or Shale

These gasolines would be expected to contain the same range of hydrocarbon types as petroleum derived gasolines. However, the concentration of aromatic hydrocarbons in the coal-derived fuels is expected to be relatively high. Experience has shown that gasolines of considerable difference in composition have the same general toxicological properties.

(a) Toxicity—Gasolines generally act as irritants to skin and mucous membrane and as anesthetics resulting from depression of the central nervous system. Mucous membrane (eye, nose, throat) irritation may be produced by vapor or liquid. Skin contact is irritating. On a prolonged or repeated basis this contact may produce defatting of the skin leading to dermatitis. The dermal toxicity of gasoline is low. It is doubtful that toxicologically significant amounts can be absorbed through the skin.

TABLE 3-6

FUEL PROPERTIES RELATED TO MAINTENANCE

	Res ON	Motor ON	Ash Wt%	Na PPM	V PPM	Carbon Residue, Wt%(a)	Sulfur Wt%	Corrosivity	Effect on Plastics	Sol. for Water @ 68°F PPM	Emulsion Tendency	Lubricity	Storage Stability	Sludge Tendency
Petroleum														
- Gasoline	86-93	77-84	0	0	0	N11	0.03	NP	See Table 3-8	0.02	NP	NP	NP(e)	NP(e)
- Broad Cut			0	0	0	0				0.04				
Coal	--	--	3-15	8,000- 30,000		--	1-5			--		--	--	--
Coal/Methanol Slurry	--	--	(1-6)	(3,000- 10,000)		--	0.4-2			Infinite			(P)	
Coal/Oil Slurry	--	--	(1-6)	(3,000- 10,000)		--	0.4-2						P	
Coal Liquids														
- Jet Fuel (JP-4)	--	--	N11	N11	N11	N11								
- Diesel	--	--	N11											
- Fuel Oil	--	--	0.01		<0.1	>0.7	0.2						NP	
Shale Oil Liquids														
- Raw	--	--												
- Syncrude	--	--												
Methanol	106	92	0	0	0	0				Infinite				
Hydrogen			0	0	0	0		(h)			NP		NP	NP
Ammonia	130		0	0	0	0		(b)			NP			
Oxygenated Compounds														
- Ethanol	106	89	0		0	0				Infinite				
- Higher Alcohols	(105)	(90)	0		0	0		(d)		Infinite				
Methane	133	105	0	0	0	0		(h)			NP	NP	NP	NP
Hydrazine			0	0	0	0		(c)		Infinite			NP	
Methylamine														
Acetylene														
Vegetable Oil														

See next page for footnotes.

FOOTNOTES TO TABLE 3-6

- (a) On 10% bottoms.
- (b) Corrodes copper, brass, zinc.
- (c) Materials to be avoided include cobalt, copper, pure iron, lead, manganese, magnesium, tin, zinc.
- (d) May contain small amounts of organic acids which may corrode certain materials.
- (e) Can be controlled by careful refining and aided by the use of proper additives.
- (f) Estimated assuming Fischer-Tropsch oxygenated compounds consist of 20% methanol, 50% ethanol, 20% propanol, 10% higher oxygen compounds.
- (g) Code: NP - no problem; P - problem; () - estimated value; blank space - data currently not available.
- (h) Cryogenic hydrogen and methane require special materials to avoid embrittlement--not really corrosion.

The oral toxicity of gasoline is low; however, the aspiration effects are significant. Minute amounts of liquid gasoline which may be drawn into the lungs during ingestion can be rapidly fatal.

The most important route of entry of gasoline is by inhalation. Excessive exposure to gasoline vapors may induce symptoms of alcoholic intoxication including a feeling of fullness in the head, headache, blurred vision, dizziness, unsteadiness, nausea, and allied symptoms. The time of onset and the severity of these signs and symptoms is related to the concentration. The olefin and aromatic content of the gasoline is important as these materials are more potent anesthetics. The irritant properties of the vapor cannot always be relied upon to provide an adequate warning. The amount of benzene present in any gasoline is assumed to be important where prolonged or repeated low level exposure is possible. Benzene causes the destruction of the blood forming organs leading to aplastic anemia and has been implicated in certain cases of leukemia.

There have been recent changes in the standards of the Occupational Health and Safety Administration (OSHA) with respect to exposure to benzene, e.g., in chemical manufacturing operations. OSHA has sought an extension of these rules to petroleum operations that involve fractions containing benzene (e.g., motor gasoline). The American Petroleum Institute and the National Petroleum Refiners Association have filed suit against certain of the rules promulgated by OSHA. The case is presently in the hands of the Fifth Circuit Court in Atlanta*. It is not possible to predict the outcome of the case. However, it is recognized there is a the possibility of an impact on any fuel containing benzene, whether derived from petroleum, coal or any other source.

(b) Hazard

- Oral ingestion - low apart from risk of aspiration
- Skin penetration - low
- Inhalation - high, particularly in confined spaces where vapor concentrations can rapidly build up
- Eye, skin, nose and through contact - moderate risk of irritancy

3.5.2 Distillates from Coal or Shale

These distillates would be expected to contain the same range of hydrocarbon types as petroleum distillates in the 325-650°F boiling range.

(a) Toxicity--Distillates generally act as irritants to skin and mucous membranes. Toxicity is low by the oral, dermal, and inhalation routes.

*Platts News Service, 4/21/78.

However, aspiration, the entry of small amounts of liquid hydrocarbon directly into the lungs, rapidly produces a severe injury to lung tissues which may be fatal. The low volatility of distillates precludes vapor build-up unless the liquid has been heated.

Skin contact may be irritating and on a prolonged basis can remove sufficient fat from the skin to result in a dermatitis. Eye contact results in only slight, transient irritation.

(b) Hazard

- Oral ingestion - low apart from risk of aspiration which is very hazardous
- Skin penetration - low
- Inhalation - low
- Skin, eye, nose, and throat contact - low risk of irritancy; increasing with increased severity of exposure

3.5.3 Methanol

The following comments regarding methanol would also apply to blends containing significant amounts of the alcohol.

(a) Toxicity--Methanol is both an irritant and a central nervous system depressant. The low molecular weight alcohols share these properties although their anesthetic potency is definitely less than the comparable hydrocarbon. Toxic effects include dizziness, stupor, cyanosis, cramps, and gastric disturbances.

Prolonged vapor exposure may also lead to headache, ringing in the ears, tremor, and disturbances in nerve function. Methanol is unique among the alcohols in that it produces degeneration of the optic nerve and retina leading to complete and permanent blindness. There is apparently a wide variation in individual susceptibility to methanol.

Acute toxicity studies in animals indicate that the lethal oral dose is 18 ml/kg vs. 12.5 ml/kg for ethanol. The toxic dose for man may be as low as 10 mg/kg, and the lethal dose as low as 50 mg/kg. Toxic effects, including blindness, have also been reported in man where skin absorption and/or vapor inhalation have been involved. It is not always possible to eliminate ingestion as an additional route of exposure in such cases.

(b) Hazard

- Oral ingestion - very high
- Skin penetration - moderate
- Inhalation - low [industrial exposures should be controlled to meet a Threshold Value Limit (TLV) of 200 ppm]
- Skin, eye, nose, and throat contact - slight to moderate

3.5.4 Ethanol

The chief difficulty associated with ethanol exposure under industrial circumstances involves willful ingestion.

(a) Toxicity--Ethanol is a local irritant to the mucous membrane and also a central nervous system depressant. The action first involves inhibition of higher functions and later increasing degrees of anesthetic action. In this respect, it is more potent than methanol.

Acute toxicity studies in animals point to a lethal dose of 6-8 ml/kg. The lethal dose for an adult man is estimated to be 3 g/kg body weight (approximately 1/2 pint of absolute alcohol taken all at once). Although it is possible to produce toxic effects by skin absorption, the necessary conditions of exposure are such as to make it most unlikely. Absorption of toxic amounts of ethanol by inhalation is normally not encountered because the odor and mucous membrane irritation become intolerable before anesthetic concentrations are achieved. Repeated or prolonged exposures to ethanol vapor apparently have no chronic effect in man.

(b) Hazard

- Oral ingestion - moderate
- Skin penetration - low
- Inhalation - low (industrial exposures should be controlled to TLV of 1000 ppm)
- Skin, eye, nose, and throat contact - slight (skin) to moderate (mucous membranes)

3.5.5 Higher Oxygenates

Processes such as the Fischer/Tropsch may yield mixtures of aliphatic alcohols, with lesser amounts of aldehydes and ketones. Certain general statements can be made regarding such products. With the lower alcohols, toxicity tends to increase with increasing carbon number up through C₆. Skin penetration and irritancy effects also increase. Although the volatility is less with increasing molecular weight, the toxicity and irritancy are also greater.

With respect to ketones, industrial exposure has occurred to a considerable degree without significant health effects. Although the ketones may be toxic, the irritancy of the materials provides fairly effective warning. The vapors are considered narcotic, but concentrations required to produce obvious effects are also irritating to mucous membranes of the eyes, nose, and throat. Lower concentrations, not likely to produce discomfort, may lead to some impairment of judgment. In general, the toxicity irritation and anesthetic potency increase with increasing molecular weight. Irritancy and toxicity also increase with increasing unsaturation. The liquids are painfully irritating to the eyes, and prolonged and repeated skin contact can irritate as well as lead to dermatitis from the defatting action of the solvent. Skin absorption is not likely to result in toxic effects from the common saturated ketones.

Aldehydes have generally produced only local reactions without severe cumulative effects under occupational exposure conditions. The local reactions consist of irritation of skin and mucous membranes of the eyes, nose, and throat. The response is most characteristically seen with the lower M.W. aldehydes, particularly those with unsaturation in the aliphatic chain. Aromatic aldehydes tend to be less irritating. Sensitization, a specific form of heightened responsiveness, is well known with formaldehyde and may also occur with other aldehydes. This effect is ordinarily associated with liquid contact and is only rarely reported from vapor inhalation. Some aldehydes have an anesthetic action but this would be at a low level for aldehydes likely to be present in automotive fuels. In general, the irritating properties of the aldehyde prevent voluntary exposure to toxic or anesthetic concentrations.

3.5.6 Methane

This hydrocarbon gas is a simple asphyxiant. The only physiological effects seen are the result of a decrease in the available oxygen due to the presence of methane. It has no warning properties. The limiting factor in exposure is the partial pressure of oxygen which should not go below 135 mm in atmospheres containing no toxic gases or vapors. Compounds such as methane and ethane can produce explosion hazards; whatever precautions are taken to avoid this risk are adequate to protect against asphyxia.

3.5.7 Ammonia

The physiological effects of ammonia are directly traceable to its ability to produce local severe irritation of tissues.

(a) Toxicity--Ammonia is extremely irritating and highly corrosive to the eyes and respiratory tract. Suffocation and death from pulmonary edema can result from exposure to high concentrations. The irritant properties and pungent odor give adequate warning so that toxic exposures are not voluntarily permitted. Up to 500 ppm in air may be tolerated for an hour. Irritation of mucous membranes of the eyes, nose, and throat have been reported at 400-700 ppm. Exposures of 2500-6500 ppm have been judged dangerous for 0.5 hour, and 5000 ppm and above is believed to be rapidly fatal. High concentrations of ammonia in addition to the corrosive action on eyes, throat, and respiratory tract may also affect heart reflexes and respiratory action. Moist atmospheres containing 1% or more ammonia may cause increasing amounts of skin irritation including chemical burns with blistering. There is no evidence of cumulative or chronic toxic effects following prolonged or repeated exposures to tolerable atmospheric concentrations.

(b) Hazard

- Oral ingestion - unlikely for a gas
- Skin penetration - low
- Inhalation - moderate (industrial exposures should be controlled to TLV of 25 ppm)

- Skin, eye, nose, and throat contact - variable, depending upon concentration; can be high where exposure is severe

Note is also taken of the fact that several accidents per year involve inhalation of ammonia released by rupture of vessels containing it (e.g., railroad tank cars) or by leaks from compressors, refrigerators, etc.

3.5.8 Hydrogen

This odorless, colorless gas acts as a simple asphyxiant. The physiological effects result from a decrease in available oxygen due to the presence of hydrogen. There are no warning properties, and the onset of asphyxia may be insidious. The precautions taken to prevent fire and explosion are more than adequate to protect against oxygen deprivation and consequent asphyxia.

3.6 Safety

The major issues in fuel safety, other than toxicity, are flammability and danger of accidental detonation.

The pertinent properties of the possible alternative fuels are listed in Table 3-7. Safety precautions required for hydrocarbon liquids derived from coal and oil shale will be similar to those established for conventional petroleum fuels. However, a variety of different precautions will be required for the other fuels:

- The lower flammability limits of methanol and ethanol are 6 vol. % and 3.5 vol. %, respectively, versus about 1 vol. % for petroleum liquids. Moreover, the flash points of the pure alcohols are higher than typical values for gasoline, thereby indicating greater safety.
- Ammonia has relatively narrow limits of flammability and a high lower limit, thereby making it a comparatively safe fuel in these respects.
- Methylamine, which is more toxic than ammonia, also has somewhat wider flammability limits but a higher boiling point. On balance, methylamine may be less hazardous than ammonia.
- Methane must be handled with great care, especially as a liquid. However, safe handling procedures for LNG have been devised by the gas industry. Nevertheless, vehicular applications of LNG would differ from current gas industry experience and may involve greater hazard.
- Liquid hydrogen has been used extensively in the space program, but with rigorously controlled handling procedures. The widespread use of liquid hydrogen in distribution networks, service depots, and on board vehicles is a cause for concern.

- Acetylene is a hazardous gaseous fuel that has been handled safely in numerous industrial applications. Additional precautions and new techniques would be required to insure safety in transportation applications.
- Hydrazine is another fuel with serious safety problems, but has the advantage of being a liquid at ambient temperatures.

At present, it is an open question as to whether certain advantages of fuels such as hydrogen and methane are sufficient to offset the disadvantages of the stringent safety procedures that would be required in commercial transportation applications to control the hazardous nature of the fuels.

3.7 Properties of Non-Highway Fuels from Coal Syncrudes and Shale Oil

A considerable amount of work has been done in the recent past on producing various types of fuels from coal and shale. These studies vary widely with regard to resource source, treating conditions, and process which makes it difficult to condense the information. Accordingly, for completeness, the results of the work are presented as separate entities in Appendix 3-2. A major effort would be required to put all the data on a common, consistent, basis. To develop correlations relating coal or shale type, processing conditions and fuel properties is beyond the scope of this study. A brief summary of the pertinent article is included to give some idea of that commercial transportation fuels can be produced from coal and shale.

TABLE 3-7

FUEL PERFORMANCE CRITERIA--SAFETY(c)

Fuel	Volatility Initial Boiling Point - °F	Flammability Limits - Vol %		Vapor Pressure psi @ 100°F	Flash Point, °F (Closed Cup)	Toxicity Dangerous for Prolonged Expose., ppm	Static Charge	Corrosivity	Overall Rating (Relative to Gasoline) (h)
		Upper	Lower						
Petroleum									
- Gasoline	100	8	1	8-12	-30	500	D	NP(e)	0
- Broadcut	100	5	0.7	1-5	-30	500	D	NP(e)	0
Coal	--		50 oz per 1000 ft ³	--	--	Non-Toxic			-
Coal/Methanol Slurry	149	37	6	4	50(b)	200	LD		-
Coal/Oil Slurry	<350	--	--	>0.01	>130				-
Coal Liquids									
- Jet Fuel	190			(2)		(500)	D	NP(e)	-
- Diesel	300			0.01		(500)	D	NP(e)	-
- Fuel Oil	(400)			<0.01	>150	(500)	D	NP(e)	-
Shale Oil Liquids									
- Raw	(100)			(4)		(500)	D	NP(e)	0
- Syncrude	(100)			8		(500)	D	NP(e)	0
Methanol	149	37	6	4.6	52(b)	200	LD(d)		-
Hydrogen	-423	74	4.1	(a)	--	Asphyxiant			+
Ammonia	212	25	16	212	--	100		(f)	+
Oxygenated Compound									
- Ethanol	173	19	3.5	0.28 @ 68°F	65(b)	1000	LD(d)		-
- Higher Alcohols	150					1000	LD(d)		-
Methane	-259	15	5	(a)	--	Asphyxiant			+
Hydrazine	236	100	4.7	0.28 @ 77°F	126(b)	1	D	(g)	+
Methylamine	21	21	5			10			+
Acetylene	-119	80	2.8	(a)		Asphyxiant			+
Vegetable Oil					275				-

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See next page for footnotes.

FOOTNOTES TO TABLE 3-7

- (a) Above critical temperature.
- (b) Open cup.
- (c) D - danger; NP - no problem; LD - less danger than petroleum hydrocarbons; blank spaces - data unavailable; () - estimated data.
- (d) Specific electric conductivity 10^6 times higher than hydrocarbons.
- (e) Can be controlled by careful refining and use of additives.
- (f) Corrodes copper, brass and zinc.
- (g) Materials to be avoided include cobalt, copper, pure iron, lead, manganese, magnesium, tin and zinc.
- (h) + = more dangerous than gasoline; - = less dangerous than gasoline; 0 = equal to gasoline.

APPENDIX 3-1SIGNIFICANCE OF FUEL PROPERTIESVolatility

- Determines the ease with which a fuel can be vaporized. In carburetted engines, it controls ease of starting, warm-up, and acceleration. A final boiling point above about 400°F. may result in excessive crackcase dilution and/or engine deposits. Excessively high volatility can give rise to vapor lock problems and/or carburetor icing.
- In fuel-injected engines (e.g., diesel, gas turbine) appreciably lower volatility (i.e., higher boiling point) can be tolerated. However, fuels with final boiling points above about 650°F. may not burn cleanly, particularly in high speed reciprocating piston engines where burning time is short. The time available for burning is a function of engine speed in reciprocating piston engines and of combustor size and air rate in engines using steady state combustion (e.g., gas turbine).

Vapor Pressure

- Another measure of fuel volatility. With carburetted engines, increasing vapor pressure improves ease of starting, but enhances dangers of vapor lock and carburetor icing.

Heat of Vaporization

- A measure of the energy required to convert a unit weight of fuel from a liquid to a vapor.

In carburetted engines, the higher the heat of vaporization, the lower will be the temperature of the fuel-air mixture in the intake manifold, the greater weight of fuel (and air) inducted into the combustion chamber, resulting in more power per cycle. However, if the fuel-air mixture temperature becomes too low, a heterogeneous fuel-air mixture may result, causing poor engine operation. In this case, heat must be added to the intake manifold to vaporize the fuel.

In the case of cryogenic liquids, it also represents the amount of heat that must be added to fuel storage to provide fuel vapor for the engine.

Heat of Combustion (Net)

- The amount of heat produced by burning a unit amount of fuel in air under stoichiometric conditions to gaseous products. The

lower the heat of combustion, the more fuel that must be carried aboard a vehicle to provide a given level of energy storage.

Heat of Combustion (net) (BTU/ft³)

- The amount of heat that will be generated by burning 1 cubic foot of a stoichiometric mixture of air and fuel. Everything else being equal, the higher this figure, the more power will be generated by a carburetted reciprocating engine of given displacement

Octane Number

- Measures the resistance of the fuel to detonation in an Otto cycle engine. As octane number of a fuel is increased, the allowable engine compression ratio increases. Thus, high octane fuels are capable of increased miles/gal., since engine thermal efficiency increases with an increase in compression ratio.

Research octane number measures knock resistance under less severe conditions than the Motor Octane Number. Heretofore, the road anti-knock performance of a gasoline could be correlated best with an average of the Research and Motor Octane Numbers.

Octane Number has no significance with regard to fuel performance in an engine using steady-state combustion (e.g., gas turbine). There is a rough inverse relationship between Octane Number and Cetane Number, which makes high octane fuels unsatisfactory for use in compression ignition engines.

Cetane Number

- The higher the Cetane Number, the less the ignition delay in a compression ignition engine. Currently, #2 diesel fuels in the U.S. average 48 Cetane Number. A minimum Cetane Number of 40 is allowed by some diesel engine manufacturers. Lower Cetane Numbers may be used in heavy, slow-speed engines, particularly if auxiliary means of ignition is employed (e.g., spark or glow plug, or pilot fuel injection). It will be noted that spontaneous ignition temperature tends to decrease as Cetane Number increases.

Cetane Number has no significance regarding fuel performance in a continuous combustion engine.

Flame Speed

- Current engines have been optimized to operate best with a hydrocarbon fuel (flame speed 1.1 ft/sec). Wide variations in flame speed from this level would probably require that engine operation be modified for best results. For example, the high flame speed of hydrogen and the slow speed of ammonia suggest that expedients

must probably be used with these fuels for best operation in reciprocating engines. In continuous combustion engines, combustor residence time (e.g., combustor size) for the fuel air mixture must be increased as flame speed decreases to ensure complete combustion.

Flammability Limits

- Represent the range in fuel-air mixtures that will support a flame. In general, wide limits are an advantage in engine operation, since the probability of misfire due to engine variability and heterogeneity of the fuel-air mixture is reduced. It will also allow greater flexibility in design of continuous combustors.

Kinematic Viscosity @ 77°F

- This property is primarily of concern where fuel injection and atomization is used to introduce the fuel into the combustion space. For pressure injection, the degree of atomization becomes poorer as viscosity increases. It is of particular concern in diesel engines where the degree of spray penetration is important.

Kinematic Viscosity at 0°F

- This property is important in giving guidance as to low temperature handling properties. Pumping difficulties increase as viscosity increases.

Density

- The density of the liquid is of concern with regard to the size of storage vessels and lines in terminals, service stations, and vehicles. In general, the less dense fuel will require a greater storage volume for a given energy supply, unless the heat content (BTU/lb) compensates for the density difference.

Density is also of importance in fuel systems where the fuel is metered by volume (e.g., in diesel fuel injectors). In such a system, the more dense fuel will be supplied at a higher mass rate, which will influence fuel/air ratios, and power at a given injector setting.

Freezing Point (Pour Point)

- Represents the temperature below which the fuel becomes solid and cannot be pumped. This limits the minimum temperature at which the oil can be handled either at the terminal or aboard a vehicle.

Flash Point

- The temperature at which the bulk liquid can be ignited by an open flame. Fire hazard increases as flash point decreases.

Contact with Water

- In the normal commercial storage and transportation of fuels, it is difficult to avoid some contact and introduction of water into the system. For example, storage tanks will "breathe" and thus moisture can be introduced into the storage system. Also, floating roof tanks, used in large bulk terminals can be another source of some small amount of water into the fuel. In marine transportation, by tanker or barge, some water invariably gets into the tanks. While every precaution is taken to avoid having water in the distribution system, it is a practical problem that must be recognized. Some of the problems that can be created by water in the distribution system are:

- Solubility for Water

- If water is present, it can be precipitated when the fuel is cooled. As the solubility for water in a given fuel increases, the problems will become more severe.

- Solubility in Water

- If a given fuel (such as alcohols) are soluble in water then there can be fuel losses to the water phase.

- Emulsion Tendency

- This is the tendency for a fuel to form an emulsion when agitated with water. The greater this tendency, the greater the probability that emulsified water picked up in the fuel transportation and storage system will be carried from the storage tanks, through the fuel system, and, eventually, to the engine where it can cause engine malfunction by interfering with the smooth flow of fuel to the engine. The trouble in the engine may be caused by the poor flow characteristics of the emulsion itself, by deposit of water when the emulsion breaks, by corrosive salts dissolved in the water (e.g., sea water) or by dirt and rust suspended in the emulsion. Thus, a fuel with low tendency to emulsify or in which the emulsion breaks and settles rapidly is much easier to deliver clean to the engine than a fuel that emulsifies easily.

Storage Stability

- In the present fuel distribution system it is possible that six months or more may elapse between the time a fuel is produced at a refinery until it is burned in an engine. Thus, it is important that a fuel have the ability to retain its desirable characteristics and not degrade in storage over this period. **Instability in storage** may take a number of forms, e.g., loss of volatile fuel components, formation of gum or sediment, change in color, etc.

Static Charge

- A static electric charge can be accumulated on a liquid of low electric conductivity (e.g. a petroleum fuel) when it is moved at high velocity through pipes, filters, etc. Under proper conditions the electric charge will discharge to a conductor of lower potential (e.g. a grounded tank wall) in the form of a spark capable of igniting a combustible mixture of fuel vapor and air. Thus the tendency to develop a static charge (which is roughly an inverse function of its electrical conductivity) is of interest as one source of fire hazard in the handling of fuels.

Toxicity

- The toxicity of a fuel is of great concern and determines the precautions that must be taken in its safe handling and use. Three main types of toxicity are of interest: vapor inhalation, ingestion and skin contact. Vapor toxicity determines the care that must be taken to avoid breathing the fumes. Ingestion indicates the hazard in case of accidental swallowing of the vapor or liquid. Skin toxicity represents the hazard connected with fuel coming in contact with skin.

Lubricity

- Lubricity is the ability of a fuel to lubricate the equipment through which it flows. It is proportional to viscosity. The lubricity of the fuel can have an important effect on the type of pump used in handling. With some pumps a fuel of poor lubricity can cause excessive wear (e.g., using a diesel fuel having an undesirably low viscosity). Accordingly, care must be used in correctly matching fuel and pump. In some cases, poor lubricity may be corrected by means of a fuel additive.

Corrosivity

- A reaction (chemical, dissolution, etc.) between a fuel and the materials of the fuel system in which it is used is, of course, undesirable. It may cause engine malfunction due to formation of fuel leaks, distortion of fuel system components, development of undesirable deposits in sensitive areas, staining and coating of finely finished surfaces in controls, pumps, etc. Thus it is important that a fuel be compatible with the fuel system in which it is used. The degree of compatibility must be high since the expected service life is long (10+ yrs.) and relative small changes in sensitive parts (e.g., in metering devices) can be very troublesome.

Effect on Plastics

- In most engine fuel systems, plastic parts may be found perhaps as lines, diaphragms, gaskets, control parts, etc. It is important that the fuel be compatible with such materials and not cause them to lose strength, swell or otherwise deteriorate.

APPENDIX 3-2PROPERTIES OF NON-HIGHWAY FUELS FROM SHALE AND COAL SYNCRUDES

The published literature contains a variety of data on the properties of fuels derived from coal and oil shale. In general, the properties are in terms of "inspection data", i.e. the results of standardized analytical tests by procedures developed for quality control of conventional petroleum fuels. It should be recognized that such tests have been applied to the "alternative fuels" because these are the analytical procedures that are available; it does not follow that, in every case, the inspection data provide an accurate indication of the actual performance of the fuels in different end-uses.

Quality control of fuel manufacture requires that products meet established specifications* that are defined in terms of the inspection data obtained on samples analyzed by standardized test procedures. If the inspection results for a particular sample are within the prescribed range of the pertinent specification the batch of product from which the sample was taken is considered to be "on spec". In cases where the sample was "off spec", the batch of product would be reprocessed or rebled to produce "on spec" material.

Inspection data are also obtained routinely on samples produced during experimental work, e.g. samples obtained from pilot plant operations. In such cases, the usual purpose is to investigate the effects of process variables rather than to produce "on spec" products. Hence, the fact that an experimental sample is "off spec" does not imply that fuel of satisfactory quality cannot be produced from a particular resource or by a particular process.

There is difficulty in interpreting numerical data excerpted from published literature. "In the absence of commercial operations, all fuel samples of "alternative fuels" must be considered experimental. The difficulty is that numerical data, per se, do not convey the purpose of a given experiment. For example, was the sample taken from an experimental "run" in which the goal was to approximate an established specification as closely as possible, or was the goal to investigate process variables (such as pressure, temperature, space velocity, different catalysts, etc.)?"

In reviewing the data that follow, the reader is cautioned that there is a lack of comparability among many of the samples tested, since the samples may have been produced for quite different purposes. In consequence, the analytical results should be regarded as illustrative and not as definitive.

*Such specifications are always employed by the fuel manufacturer to meet his own needs and/or the needs of a purchaser (in which case the specification may be a "procurement" or "purchasing" specification).

A. Military Fuels from Crude Shale Oil(3-16)

The production of 5,765 bbl of various military operational fuels (JP-4, JP-5/Jet A, DFM/DF-2, gasoline, Heavy Fuel Oil) from 10,000 bbl of crude shale oil was accomplished in a commercial refinery having a capacity of about 9,000 BPSD.

The 10,000 bbl of crude shale oil was produced by the Paraho process using the shale mined from the Naval Oil Shale Reserve located near Anvil Points, Colorado.

The various fuels produced met a majority of the military, federal, and commercial specifications requirements (see Tables 3-8, 3-9, 3-10 and 3-11). However, these fuels tended to exhibit storage and thermal instabilities. In addition, the fuels contained a high wax content, high particulate matter, and high gum content. It is believed that a higher pressure in the hydrogenation stage (about 1500 to 3,000 psi), along with clay treatment of the final products, would reduce or eliminate some or most of these problem areas.

It is concluded that it is feasible to obtain military and civilian operational fuels from shale oil crude using a commercial refinery. However, additional effort has to be expended to overcome some refinery and operational problems to obtain maximum yields and improved properties.

B. Jet Fuels from Synthetic Crudes (3-6)

Three syncrudes were used, one from shale and two from coal, chosen as representative of typical crudes from future commercial production. From them, jet fuels of varying specifications were produced by distillation, hydrotreating and hydrocracking. The crudes were fractionated at atmospheric pressure and under vacuum prior to hydroprocessing. The yields for each fraction (and some of the properties) are shown in Table 3-12. Table 3-13 (lists the product specification targets used to guide the processing. Table 3-14 shows the properties of the fuels prepared to varying specifications.

Certain problem areas have been identified. The yield of the 300-500°F fraction was unexpectedly low from the shale oil and additional processing (e.g., delayed coking) is required to convert high boiling fractions to the jet fuel range with some shale oils. The H-coal material used in this study was also deficient in the distillate range and may indicate the need for processing of the high boiling fractions. Rapid catalyst deactivation of the hydrovisbreaking and hydrocracking catalysts was observed with the COED syncrude. The reason for this is not reported.

TABLE 3-8

UNINHIBITED HYDROGENATED NAPHTHA FRACTION:
GASOLINE SPECIFICATION TESTS

	<u>Hydrotreated Naphtha*</u>	<u>NATO F-46 Gasoline Spec.</u>
Sample No.	1512	----
API Gravity	66.7	-----
ASTM Dist. °F		
IBP	110	----
10 percent recov.	165	122 - 158
50 percent recov.	223	190 - 239
90 percent recov.	285	270 - 356
EP	333	----
Vol. percent res.	1.0	2.0 max.
Vol. percent loss	1.0	----
R.V.P. psi	5.5	9 max.
Existent gum, mg/100 ml	9.6	4 max.
Corrosion, 3 hrs. @ 50°C	3B	1 max.
Sulfur, Wt. percent	< 0.002	0.10 max.
Oxidation Stability, hrs.	> 24	8 min.
R.O.N.	47.6	91
M.O.N.	48.0	83
Lead, g/l	none	0.65 max.
Additives		
Oxidation Inhibitors	none	as req'd by procuring agency
Metal Deactivators	none	" " " " " " " " "
Corrosion Inhibitors	none	" " " " " " " " "

*Sample prepared by Hypercal fractionation to an IBP - 300°F cut from Sample #1714,
HDN Run #1 Product.

Source: Ref. 3-16

TABLE 3-9

UNINHIBITED HYDROGENATED JET FUEL FRACTIONS:
SPECIFICATION TESTS

Sample No./Product	0554	0555	0556
	JP-5	JP-4	Jet-A
Distillation, IBP	351	136	317
10 percent	370	215	359
50 percent	394	350	420
90 percent	428	434	473
EP	453	462	493
Percent Res.	1.0	1.0	1.0
Percent Loss	0	2.0	0
RVP, #IN ²	---	2.3	---
Flash PT, °F (TCC)	140	---	128
Freeze PT, °F	-57	-71.5	-39
Viscosity @ -30°F, CS	6.91	2.89	9.16
Water Tol. ~ Vol. Change	0.0	0.0	0.0
~ Interface Rating	1	1	1
Total S, Wt. percent	< 0.002	0.004	< 0.002
Copper Corrosion (2 hrs. @ 212)	1A	2C	1A
RSH-S, Wt. percent	0.00013	0.00014	0.00016
Aromatics, vol. percent	19.1	11.1	20.5
Olefins, vol. percent	1.5	1.0	0.9
Acid NO, mgKOH/ml	nil	nil	nil
API Grav.	44.9	53.1	43.5
Spec. Grav.	0.8022	0.7665	0.8086
Net Heat of Combustion, BTU/LB	18554	18715	18570
Aniline PT, °F	135.0	134.5	187.0
Existent Gum, mg/100 ml	3.8	5.0	8.2
Potential Gum, mg/100 ml (16 hr)	109.8	Insuff. Samp.	102.0
Smoke PT.	24.0	31.0	22.0
Smoke Volatility Index	---	61.5	---

TABLE 3-10

UNINHIBITED HYDROGENATED DIESEL FRACTIONS:
SPECIFICATION TESTS

Code Sample # TBP Cut PTS °F	Diesel (DF -2) 75-1510-4 440 - 600	DFM 75-1506-4 440 - 640
Color	2.5	3.0
API Gravity	30.4	30.2
ASTM Dist. °F		
IBP	496	497
5	508	517
10	510	523
50	531	554
90	563	597
95	572	604
EP	578	612
Cloud, °F	-10	+12
Pour, °F	-10	+15
Sulfur, Wt. percent	0.002	0.002
Carb. Res. (10% Btms) Wt. percent	0.2	0.2
Corrosion, 3 hrs. @ 212°F	1A	1B
Ash, Wt. percent	NIL	NIL
Vis. @ 100°F, CS	3.31	4.06
Accel. Stability	Insuff. Sample	Insuff. Sample
Flash °F	228	230
Acid No.	NIL	NIL
Cetane No.	Insuff. Sample	Insuff. Sample

Source: Ref. 3-16

TABLE 3-11NO. 6 FUEL OIL BLENDING
SPECIFICATION TESTS

Sample No.	1646	1595
Component	Total Feed in Tank after Coking Run #2	600 - 700° Raw HDN #3 Feed
Inspections:		
°API	15.2	21.8
Wt. percent S	0.46	0.60
Pour, °F	90	50
<hr/>		
	50-50 Volumetric Blend Samples #1646 & #1595 (Sample #1511)	MIL-F-859E Burner Fuel Oil Specifications
°API	18.4	11.5 min.
Flash, °F	330	150 min.
Vis. @ 122°F, SSU	164.5	225 max.
Ash, Wt. percent	0.033	0.10 max.
H ₂ O by dist'r, Wt. percent	trace	0.50 max.
Pour, °F	75	15 max.
Carbon Residue, Wt. percent		15 max.
Sediment by est., Wt. percent	0.04	0.12 max.
Sulfur, Wt. percent	0.55	3.50 max.
Thermal Stability - NBTL	not run	1 min.
Explosiveness, percent	not run	50 max.

Source: Ref. 3-16

TABLE 3-12

CRUDE OIL COMPOSITE FEED AND FRACTIONS

A. TOSCO Shale Oil

	Feed	IBP-422 K (IBP-300° F)	422 to 561 K (300 to 550° F)	561 to 616 K (550 to 650° F)	616 to 700 K (650 to 800° F)	700 to 783 K (800 to 950° F)
Wt.-% on whole shale	100.0	9.4	18.4	6.6	12.1	18.3
API gravity	19.1	51.1	32.8	22.3	19.4	—
% Sulfur	0.683	0.770	0.735	0.673	0.643	—
% Carbon	83.88	86.83	84.58	84.68	85.38	—
% Hydrogen	10.74	13.17	12.14	11.37	11.32	—
% Nitrogen	2.10	0.39	1.39	2.12	1.96	—

B. H-coal

	Feed	IBP-422 K (IBP-300° F)	422 to 561 K (300 to 550° F)	561 to 616 K (550 to 650° F)	616 K+ (650° F+)	Vacuum bottoms
Wt.-% of total liquid	100	25	61.4	8.1	5.2	—
Wt.-% of total syncrude	28.44	7.11	17.46	2.30	1.48	71.56
Wt.-% of total syncrude, ash free	38.91	9.73	23.89	3.15	2.02	61.09
API gravity	31.0	50.3	27.5	14.5	5.4	—
% Hydrogen	11.8	13.3	11.2	10.0	9.0	5.75
% Carbon	87.1	86.6	87.2	89.2	89.2	74.39
% Sulfur	0.170	0.129	0.073	0.110	0.199	1.93
% Nitrogen	0.1722	0.0659	0.1749	0.1651	0.5044	1.16
% Oxygen	0.48	0.61	1.00	0.49	1.34	4.60
% Ash	0.0	—	—	—	—	14.62

C. COED oil

	Feed	IBP-422 K (IBP-300° F)	422 to 561 K (300 to 550° F)	561 to 616 K (550 to 650° F)	616 to 700 K (650 to 800° F)	700 K+ (800° F+)
% Total syncrude	100	4.0	32.5	18.0	27.0	18.5
API gravity	18.2	47.8	25.2	18.0	16.5	9.6
% Hydrogen	10.94*	14.8	11.23	10.58	10.86	10.09
% Carbon	87.48	85.2	86.45	87.9	88.10	87.54
% Sulfur	0.023*	0.027	0.021	0.016	0.032	<0.02
% Nitrogen	0.3853	0.0677	0.3696	0.3726	0.3399	0.4285
% Oxygen	0.98*	0.34	1.31	0.86	0.74	1.02
% Ash	0.05	—	—	<0.001	<0.02	0.03

*Back calculated from analyses of fractions

TABLE 3-13

PRODUCT SPECIFICATION TARGETS TO
GUIDE PROCESSING

Yield of 300-550°F fraction, wt% on Crude (Min.).	20	40		
Hydrogenation Severity:	<u>Low</u>	<u>High</u>		
Aromatics, % max	40	20		
Hydrogen, % min	12.75	13.5		
Sulfur, % max	0.5	0.2		
Nitrogen, % max	0.2	0.1		
	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>
Volatility Specifications,				
Final Boiling Point °F	550	650	550	650
Reid Vapor Press, PSI max	3	3	--	--
Flash Point °F (min)	--	--	100	100

Source: Ref. 3-6

TABLE 3-14
FINAL PRODUCT INSPECTIONS

(a) Low yield shale products

	Low severity				High severity			
	Boiling range, K (° F)							
	IBP-616 (IBP-650)	394 to 616 (250 to 650)	394 to 561 (250 to 550)	IBP-561 (IBP-550)	IBP-616 (IBP-650)	394 to 616 (250 to 650)	394 to 561 (250 to 550)	IBP-561 (IBP-550)
Specific gravity	0.8040	0.8170	0.8068	0.7945	0.7977	0.8081	0.8022	0.7914
Reid vapor pressure, kN/sq.m. (lb./sq.in.)	1.1 (0.15)	—	—	0.34 (0.05)	2.8 (0.40)	—	—	1.1 (0.15)
Flash point, K (° F)	— —	315 (108)	311 (100)	— —	— —	312 (102)	312 (102)	— —
Freezing point, K (° F)	255 (0)	258 (+5)	229 (-47)	225 (-54)	225 (+1)	258 (+5)	231 (-44)	229 (-47)
Viscosity at 239 K (-30° F) cS	(a)	(a)	6.781	4.736	(a)	(a)	6.990	5.059
Net heat of combustion, cal./g.	10,477	10,433	10,545	10,428	10,545	10,482	10,466	10,499
Existing gum, mg.	16.2	51.4	40.2	32.2	0.8	19.2	8.6	9.0
Smoke point	21	20	21	22	26	26	24	26
Aromatics, %	21.9	25.9	22.2	19.0	13.7	17.4	17.1	13.5
Olefins, %	1.1	0.8	1.1	1.0	0.8	1.0	1.2	0.9
Naphthalenes, %	1.0	1.2	0.5	0.5	0.4	0.4	0.2	0.2
Hydrogen, %	13.64	13.66	13.68	13.73	13.82	13.86	13.95	13.76
Nitrogen, %	0.1954	0.2233	0.2011	0.1750	0.0161	0.0168	0.0152	0.0132
Total sulfur, %	0.0010	0.0044	0.0005	0.0006	0.0009	0.0003	0.0001	0.0002
Mercaptans, %	0.0002	0.0002	0.0002	0.0002	0.0003	0.0002	—	—
Oxygen, %	0.03	0.05	0.06	0.04	0.03	0.05	0.09	0.09

(b) High yield shale products

Specific gravity	0.7972	0.8146	0.8054	0.7874	0.7936	0.8100	0.8035	0.7874
Reid vapor pressure, kN/sq.m. (lb./sq.in.)	7.6 (1.10)	—	—	6.9 (1.00)	8.6 (1.25)	—	—	7.6 (1.10)
Flash point, K (°F)	—	314 (106)	312 (102)	—	—	312 (102)	309 (96)	—
Freezing point, K (°F)	251 (-8)	255 (-1)	227 (-50)	222 (-59)	250 (-9)	254 (-3)	226 (-52)	223 (-58)
Viscosity at 239 K (-30°F) cS	(a)	(a)	6.918	4.093	—	—	7.060	4.326
Net heat of combustion, cal./g.	10,565	10,531	—	10,622	10,595	10,488	10,532	10,605
Existing gum, mg.	26.8	61.8	23.4	17.0	9.2	32.8	16.0	16.6
Smoke point	23	20	22	25	26	25	25	27
Aromatics, %	15.7	20.3	17.9	13.7	12.1	15.4	13.2	11.4
Olefins, %	0.8	0.9	1.3	0.8	0.6	1.0	1.0	0.8
Naphthalenes, %	0.75	0.93	0.42	0.33	0.3	0.35	0.21	0.17
Hydrogen, %	13.82	13.37	13.80	13.70	13.98	13.95	13.95	13.98
Nitrogen, %	0.1305	0.1581	0.1397	0.1138	0.0101	0.0144	0.0076	0.0088
Total sulfur, %	0.0014	0.0012	0.0006	0.0005	0.0011	0.0002	0.0002	0.0002
Mercaptans, %	0.0001	—	—	—	<0.0001	—	—	—
Oxygen, %	0.08	0.14	0.14	0.13	0.11	0.10	0.07	0.10

TABLE 14 (Continued)

(c) Low yield H-Coal products

	High severity				Low severity			
	Boiling range, K (°F)							
	IBP-616 (IBP-650)	394 to 616 (250 to 650)	394 to 561 (250 to 550)	IBP-561 (IBP-550)	IBP-616 (IBP-650)	394 to 616 (250 to 650)	394 to 551 (250 to 550)	IBP-561 (IBP-550)
Specific gravity	0.8493	0.8654	0.8565	0.8413	0.8338	0.8488	0.8468	0.8314
Reid vapor pressure, kN/sq.m. (lb./sq.in.)	1.4 (0.20)	—	—	1.1 (0.15)	1.7 (0.25)	—	—	3.1 (0.45)
Flash point, K (°F)	—	312 (102)	309 (96)	—	—	312 (102)	314 (106)	—
Freezing point, K (°F)	251 (-8)	237 (-32)	217 (-68)	211 (-79)	255 (0)	246 (-17)	225 (-54)	207 (-86)
Viscosity at 239 K (-30° F)cS	—	16.99	6.785	5.162	9.757	15.91	9.102	6.264
Net heat of combustion, cal./g.	10,363	10,248	10,303	10,340	10,450	10,462	10,462	10,421
Existing gum, mg.	6.0	74.0	92.0	10.2	4.8	110.8	11.2	9.8
Smoke point	14	15	15	16	24	21	24	25
Aromatics, %	29.7	33.8	30.9	26.3	5.9	6.7	5.8	5.5
Olefins, %	1.2	1.8	1.4	1.2	1.3	1.4	1.0	0.9
Naphthalenes, %	0.54	0.66	0.31	0.27	0.064	0.077	0.065	0.055
Hydrogen, %	12.73	12.47	12.64	12.79	13.56	13.26	13.31	13.73
Nitrogen, %	0.0005	0.0006	0.0006	0.0001	<0.0001	<0.0001	<0.0001	0.0001
Total sulfur, %	0.0004	0.0004	0.0001	0.0001	0.0005	0.0005	<0.0001	0.0001
Mercaptans, %	—	—	—	—	—	—	—	—
Oxygen, %	0.11	0.09	0.06	0.10	0.04	0.06	0.03	0.04

(d) High yield COED products

Specific gravity	0.8255	0.8458	0.8368	0.8165	0.8358	0.8586	0.8493	0.8270
Reid vapor pressure, kN/sq.m. (lb./sq.in.)	5.8 (0.85)	—	—	5.8 (0.85)	5.8 (0.85)	—	—	7.2 (1.05)
Flash point, K (°F)	—	313 (104)	314 (106)	—	—	319 (114)	313 (104)	—
Freezing point, K (°F)	242 (-23)	239 (-30)	220 (-64)	215 (-72)	256 (-23)	256 (+2)	221 (-62)	217 (-70)
Viscosity at 239 K (-30° F)cS	(a)	19.25	9.676	5.555	(a)	(a)	9.851	5.586
Net heat of combustion, cal./g.	10,484	10,534	10,484	10,547	10,328	10,427	10,401	10,486
Existing gum, mg.	0.8	23.0	6.6	7.6	1.6	21.2	2.4	3.2
Smoke point	20	20	24	27	16	14	16	19
Aromatics, %	9.3	11.6	7.2	5.4	22.4	28.5	25.2	20.1
Olefins, %	0.7	1.1	0.9	0.5	0.6	1.2	0.8	0.5
Naphthalenes, %	0.49	0.62	0.13	0.11	0.68	0.86	0.38	0.31
Hydrogen, %	13.6	13.44	13.63	13.69	13.07	12.89	12.96	13.24
Nitrogen, %	0.0002	0.0002	0.0002	0.0002	0.0003	0.0002	0.0002	0.0002
Total sulfur, %	0.0003	0.0003	0.0001	0.0001	0.0003	0.0001	0.0001	0.0001
Mercaptans, %	—	—	—	—	—	—	—	—
Oxygen, %	0.05	0.05	0.05	0.03	0.03	0.03	0.03	0.03

^aSolid

Regarding product quality, the inspections in Table 3-14 indicate that the requirement for limits on aromatics (<20%, <40%) were met. The requirements for percent hydrogen were met for all shale products and for most of the coal products. The requirements for sulfur were met for all of the products, and with one or two exceptions the requirements for nitrogen content were met for all products. The existing gum levels were high in some cases and may indicate a stability problem that requires further study.

C. Jet A from Shale Oil (3-8)

A 300-gal. sample of Jet A quality aviation turbine fuel was produced from a 310/500°F kerosine cut from raw Paraho shale oil by hydrofining using a commercially available NiMo catalyst (HD8-3A). The processing conditions were as follows:

LHSV: 1.0
 Pressure psig: 1200
 Temperature, °F: 700
 Treat Gas, SCF/B (100% H₂): 4000

As shown in Table 3-15, the composite sample inspections met all those required for Jet A aviation turbine fuel.

D. Flammability and Ignition Properties of JP-5 Fuels from Various Sources (3-2)

The flammability and ignition properties of JP-5 from various sources are shown in Table 3-16. The tar-sand, shale-oil and one of the coal samples had flash points which were below the 140°F min specification requirement. The remaining fuels from coal had flash point higher than specification requirements and also higher than the usual run of petroleum JP-5. Flammability indices of the alternate fuels differ somewhat from that of petroleum fuels. In general, the flammability properties of the JP-5 from alternate sources were not significantly different from that of JP-5 from petroleum.

E. Gasoline from Coal and Shale (3-17)

Experimental batches of gasolines and naphthas were prepared from syncrudes derived from coal and oil shale. The data in Table 3-17 compares the composition of gasoline from shale oil to petroleum derived gasoline. Table 3-18 gives published data for syncrude naphthas. Although in actual practice the synfuels may have compositions different from those shown, these data do give an indication of what might be expected. The indications are that the naphtha composition is very dependent on coal or shale oil sources and the liquefaction processes. The H-coal hydrogenation produced more 2+ ring aromatic compounds than the COED process and the Wyoming subbituminous coal produced naphtha with a higher concentration of nitrogen compounds than the Illinois bituminous. The last two naphthas would probably be refined further to remove nitrogen and 2+ ring aromatics before using in commercial gasolines.

TABLE 3-15PRODUCT QUALITY OF HYDROTREATED PARAHO SHALE OIL

	<u>Jet A Spec</u>	<u>Hydrotreated Paraho Shale Oil</u>
Total Sulfur Content, wppm	Max. 3000	115
FIA Aromatics, Vol. %	Max. 20	14.3
PM Closed Cup Flash Pt., °F	Min. 105	127.6
Freeze Pt., °F	Max. -36	-42.7
Smoke Pt., mm	Min. 25	26.6
Kin. Viscosity @ -30°F, cs	Max. 15	9.13
<u>ASTM D-86</u>		
10%, °F	Max. 400	366
50%, °F	Max. 450	407
FBP	Max. 550	496
API Gravity	39-51	46.0

Source: Ref. 3-8

TABLE 3-16

FLAMMABILITY PROPERTIES OF JP-5 FUELS FROM ALTERNATE SOURCES

SOURCE	NRL No.	FLASH POINT (°F)		FLAM. INDEX* at 125° (%)	AIT (°F) ^{3**}
		TAG ¹	.PMCC ²		
Tar Sands	75-7	131	135	91.0	478
Shale Oil	75-12	134	137	87.8	466
Coal (HAK)	75-13	136	139	86.0	487
Coal (LAK)	75-5	169	170	31.5	487
Coal (LAU)	75-6	169	172	30.2	478
Coal (HAK)	75-3	173	174	22.8	486
Coal (HAU)	75-4	175	181	21.9	489
Petroleum	73-1	141	143	56.0	469
Petroleum	70-9	141	149	62.0	489

Notes: 1 - Tag Closed Cup, ASTM D-56

2 - Pensky-Martens Closed Cup, ASTM D-93

3 - Minimum autoignition temperature, ASTM D-2155

* Ratio of vapor conc. in air to that at lower inflammability limit

** Autoignition temperature

Source: Ref. 3-2

TABLE 3-17

COMPOSITION OF SYNTHETIC GASOLINE
FROM THE PARAHO PROCESS

	<u>Gasoline from Shale</u>	<u>Commercial Unleaded Gasoline</u>
Paraffins, Vol %	44	34
Olefins, Vol %	12	19
Naphthenes, Vol %	8	18
Aromatics, Vol %	36	29
Aromatic Distribution, Vol %		
Benzene	1.4	0.6
Toluene	7.0	2.1
Ethylbenzene	1.5	1.4
M&P Xylene	6.6	4.7
O-Xylene	2.5	2.4
C ₉ + Aromatics	14.7	16.1
Oxygen, Wt%	0.52	Nil
Nitrogen, Wt%	0.03	Nil

Source: Ref. 3-17

TABLE 3-18

**PROPERTIES AND HYDROCARBON COMPOSITION
OF NAPHTHAS FROM SYNCRUDES**

Source	Oil Shale, Wyoming	Oil Shale, Colorado	Bituminous Coal, Illinois	Bituminous Coal, Illinois	Subbituminous Coal, Wyoming
Liquefaction process	In Situ Combustion	Combustion Retort	COED, Pyrolysis	II-Coal, Hydrogenation	II-Coal Hydrogenation
Treatment of crude oil	Coked and Hydrogenated	Coked and Hydrogenated	Hydrogenated	---	---
Boiling range, °F	175°-350°F	180°-400°F	180°-390°F	C ₄ -400°F	C ₄ -400°F
Fraction of crude oil, vol %	22.4	34.5	33.1	33	57
Gravity, ° API	52.6	51.3	43.8	49.2	50
Hydrogen, wt %	---	14.2	---	---	---
Nitrogen, wt %	0.0001	0.024	0.013	0.10	0.20
Sulfur, wt %	0.001	0.001	0.009	0.099	<0.07
Octane number, Research	---	32.8	70.1	---	---
Hydrocarbon type, wt %:					
Paraffins	42.8	47.7	7.1	12.0	18.9
Monocycloparaffins	} 43.4	34.5	58.9	47.9	44.5
Cycloparaffins, 2° rings		2.4	12.5	14.5	15.0
Alkyl benzenes	} 13.8	13.2	19.8	17.6	14.2
Aromatics, 2° rings		2.2	1.7	7.0	5.9
Nonhydrocarbons	<0.001	---	---	0.9	1.7

Source: Ref. 3-17

F. JP-5 Fuels from Coal (3-5)

The properties of JP-5 type fuels derived from Western Kentucky and Utah coals are shown in Tables 3-19 to 3-22 inclusive. The syncrudes from each coal were processed to produce a high aromatic (20-25 vol%) (single-stage hydrotreat) and low aromatic (0-5 vol%) (two-stage hydrotreat) product.

In general, the API gravity of all these products was below minimum specifications and the viscosity was slightly high. The smoke point was too low with all samples except the low aromatic fuel from Utah coal. The acid number tended to be relatively high for the high aromatic products. It appears to be more difficult to meet the freezing point with the Utah coal product than with that from Western Kentucky.

Figure 3-1 shows that a high hydrogen content will usually be accompanied by a high smoke point.

Table 3-23 from another source (3-18) also indicates that it may be difficult to meet smoke point with a gas turbine engine fuel produced from a Western Kentucky coal.

G. Navy Boiler Fuel from Coal (3-7)

The Naval Ship Research and Development Center has determined the characteristics of Navy Distillate type boiler fuel that might be produced from coal. The data are shown in Table 3-24. The coal-derived samples tested are deficient in the cetane number and API gravity requirements of MIL-F-24397 fuel specifications.

H. Gas Turbine Fuels from Synthetic Crude Oils (3-19)

"Synthetic" jet fuels from both shale and coal syncrudes were produced by a processing sequence employing fractional distillation and catalytic hydrogenation. Feed fractions encompassing the jet fuel boiling range were distilled from the starting crude oils and hydrotreated at varying severity over nickel and/or cobalt-molybdenum catalysts. Final narrow cut (Jet A) and/or wide-cut (JP-4) fuels were blended from the hydrotreated products and their properties determined. These inspections are listed in Tables 3-24 to 3-29. It appears that the production of aircraft jet fuels from shale oil-derived crude is technically feasible and should be more straightforward than would be the comparable production from coal-derived oils. Hydroprocessing severity is important to the production of specification fuels. Production of specification jet fuel from shale liquids will require moderate severity hydroprocessing @ 1500 psi total pressure. Coal-derived fuels, however, will not meet density specifications unless hydrotreated at 2200 psi. Increasing processing severity, in general, improved the thermal stability and decreased the aromatic hydrocarbon and nitrogen content of the product fuel. Sulfur levels of the processes fuels were all well below specifications at all processing severities.

TABLE 3-19

SPECIFICATION ANALYSIS OF PHASE I JP-5 TYPE FUEL DERIVED FROM COAL

Fuel: No. 0001, High Aromatic (20-25 vol %): Coal Source: Western Kentucky

TEST	ASTM STANDARD	SPECIFICATION MIL-T-5624K REQUIREMENTS	RESULTS	
			SUN OIL COMPANY	NAPTC
Distillation Temperature, °C (°F)	D-86			
Initial Boiling Point		Report	188 (371)	202 (396)
10%		205 (401) max	212 (414)	213 (416)
20%		Report	217 (423)	219 (426)
50%		Report	234 (453)	237 (458)
90%		Report	266 (510)	267 (513)
End Point		290 (554) max	279 (535)	283 (542)
Residue, vol %		1.5 max	1.0	1.0
Loss, vol %		1.5 max	1.0	0.0
Gravity, °API	D-287	36 min/48 max	30.8	30.2
Freezing Point, °F	D-2386	-46 (-51) max	-56 (-68)	-48 (-54)
Aromatics, vol %	D-1319	25.0 max	22.7	24.8
Smoke Point, mm	D-1322	19 min	11	17.0
Flash Point, °C (°F)	D-93	60 (140) min	80 (176)	80 (176)
Existent Gum, mg/100 ml	D-381	7 max	2	0.0
Sulfur, Wt. %	D-1266	0.4 max	< 0.001	0.05
Thermal Stability	D-3241	Pass at 260°C (500°F)	-	Pass at 257°F (495°F)
Heating Value, MJ/kg (BTU/lb)	D-240	42.6 (18,300) min	43.0 (18,470)	42.6 (18,294)
Viscosity, cSt @ -34°C (-30°F)	D-445	16.5 max *	23.5	23.69
Olefins, vol %	D-1319	5.0 max	1.1	1.0
Particulate Matter, mg/l	D-2276	1.0 max	0.04	1.0
Total Acid No.	D-974	0.015 max	0.081	-
Nitrogen, Wt. %	-	N/A	< 0.05	-
Carbon, Wt. %	-	N/A	86.82	89.00
Hydrogen Wt. %	-	N/A	12.75	12.85

*Value taken from MIL-T-5624J.

ce: Ref. 3-5

TABLE 3-20

SPECIFICATION ANALYSIS OF PHASE I JP-5 TYPE FUEL DERIVED FROM COAL

Fuel: No. 0003, High Aromatic (20-25 vol%); Coal Source: Utah

TEST	ASTM STANDARD	SPECIFICATION MIL-T-5624K REQUIREMENTS	RESULTS	
			SUN OIL COMPANY	NAPTC
Distillation Temperature, °C (°F)				
Initial Boiling Point	D-86	Report	207 (405)	209 (408)
10%		205 (401) max	217 (423)	219 (426)
20%		Report	221 (430)	223 (434)
50%		Report	234 (454)	238 (460)
90%		Report	262 (503)	264 (508)
End Point		290 (540) max	284 (543)	279 (535)
Residue, vol %		1.5 max	1.0	1.2
Loss, vol %		1.5 max	1.0	0.0
Gravity, °API	D-287	36 min/48 max	32.8	32.4
Freezing Point, °C (°F)	D-2386	-46 (-51) max	-43 (-46)	-40 (-40)
Aromatics, vol %	D-1319	25.0 max	21.8	24.1
Smoke Point, mm	D-1322	19 max	11	17.0
Flash Point, °C (°F)	D-93	60 (140) min	80 (176)	81 (178)
Existent Gum, mg/100 ml	D-381	7 max	1	0.1
Sulfur, Wt. %	D-1266	0.4 max	< 0.0001	0.04
Thermal Stability	D-3241	Pass at 260°F (500°C)	-	Pass at 263°C (505°F)
Heating Value, MJ/KG (BTU/lb)	D-240	42.6 (18,300) min	-	42.7 (18,372)
Viscosity, cSt @ -34°C (-30°F)	D-445	16.5 max*	22.52	22.94
Olefins, vol %	D-1319	5.0 max	0.9	1.20
Particulate Matter, mg/l	D-2276	1.0 max	0.4	1.45
Total Acid No.	D-974	0.015 max	0.2	-
Nitrogen, Wt. %	-	N/A	0.27	-
Carbon, Wt. %	-	N/A	84.94	84.90
Hydrogen, Wt. %	-	N/A	14.78	13.40

*Value taken from MIL-T-5624J.

Source: Ref. 3-5

TABLE 3-21

SPECIFICATION ANALYSIS OF PHASE I JP-5 TYPE FUEL DERIVED FROM COAL

Fuel: No. 0003 Low Aromatic (0-5 vol %): Coal Source: Western Kentucky

TEST	ASTM STANDARD	SPECIFICATION MIL-T-5624K REQUIREMENTS	RESULTS	
			SUN OIL COMPANY	NAPTC
Distillation Temperature, °C (°F)	D-86			
Initial Boiling Point		Report	199 (309)	200 (392)
10%		205 (401) max	212 (413)	213 (416)
20%		Report	217 (423)	219 (426)
50%		Report	235 (455)	238 (460)
90%		Report	268 (515)	270 (518)
End Point		290 (540) max	277 (530)	286 (546)
Residue, vol %		1.5 max	0.4	1.0
Loss, vol %		1.5 max	1.6	0
Gravity, °API	D-287	36 min/48 max	32.4	31.8
Freezing Point, °C (°F)	D-2386	-46 (-51) max	-54 (-65)	-50 (-58)
Aromatics, vol %	D-1319	25.0 max	3.1	4.69
Smoke Point, mm	D-1322	19 min	16	22
Flash Point, °C (°F)	D-93	60 (140) min	76 (168)	79 (174)
Existent Gum, mg/100 ml	D-381	7 max	1	0
Sulfur, Wt. %	D-1266	0.4 max	< 0.0001	.005
Thermal Stability	D-3241	Pass at 260°C (500°F)	-	Pass at >371°C (700°F)
Heating Value, MJ/kg (BTU/lb)	D-240	42.6 (18,300) min	-	42.8 (18,383)
Viscosity, cSt @ -34°C (-30°F)	D-445	16.5 max *	25.52	25.95
Olefins, vol %	D-1319	5.0 max	2.8	1.56
Particulate Matter, mg/l	D-2276	1.0 max	0.39	0.93
Total Acid No.	D-974	0.015 max	0.005	-
Nitrogen, Wt. %	-	N/A	0.13	-
Carbon, Wt. %	-	N/A	85.75	85.6
Hydrogen, Wt. %	-	N/A	14.11	13.4

*Value taken from MIL-T-5624J.

Source: Ref. 3-5

TABLE 3-22

SPECIFICATION ANALYSIS OF PHASE I JP-5 TYPE FUEL DERIVED FROM COAL

Fuel: No. 0004, Low Aromatic (0-5 vol. %): Coal Source: Utah

TEST	ASTM STANDARD	SPECIFICATION MIL-T-5624K REQUIREMENTS	RESULTS	
			SUN OIL COMPANY	NAPTC
Distillation Temperature, °C (°F)	D-86			
Initial Boiling Point		Report	206 (402)	207 (404)
10%		205 (401) max	217 (422)	218 (424)
20%		Report	222 (432)	222 (432)
50%		Report	236 (456)	236 (456)
90%		Report	254 (508)	263 (506)
End Point		290 (540) max	284 (544)	282 (539)
Residue, vol %		1.5 max	1.0	1.1
Loss, vol %		1.5 max	1.0	0
Gravity, °API	D-287	36 min/48 max	34.8	35.2
Freezing Point, °F	D-2386	-46 (-51) max	-42 (-44)	-40 (-40)
Aromatics, vol %	D-1319	25.0 max	2.9	6.1
Smoke Point, °C (°F)	D-1322	19 max	26	22
Flash Point, °C (°F)	D-93	60 (140) min	82 (180)	83 (182)
Existent Gum, mg/100 ml	D-381	7 max	-	0.1
Sulfur, Wt. %	D-1266	0.4 max	< 0.0601	0.093
Thermal Stability	D-3241	Pass at 260°C (500°F)	-	Pass at 368°C (695°F)
Heating Value, MJ/kg (BTU/lb)	D-240	42.6 (18,300) min	-	42.9 (18,465)
Viscosity, cSt @ -34°C (-30°F)	D-445	16.5 max*	22.7	23.03
Olefins, vol %	D-1319	5.0 max	2.7	2.6
Particulate Matter, mg/l	D-2276	1.0 max	0.21	1.13
Total Acid No.	D-974	0.015 max	0.005	-
Nitrogen, Wt. %	-	N/A	< 0.04	-
Carbon, Wt. %	-	N/A	84.41	84.2
Hydrogen, Wt. %	-	N/A	15.54	13.1

*Value taken from MIL-T-5624J.

Source: Ref. 3-5

FIGURE 3-1VARIATION IN SMOKE POINT VALUES
FOR FUEL DERIVED FROM COAL

Source: Ref. 3-5

TABLE 3-23

HYDROGENATION CONDITIONS AND PROPERTIES OF GAS
TURBINE ENGINE FUEL SAMPLE PREPARED FROM COAL SYNCRUDE

HYDROGENATIONFeedstock

Syncrude Coal Source
Aromatics (D1319), Vol.%

Western Kentucky
48.8

Conditions

Catalyst (American Cyanamid)
Temperature, °F (Zone Outlets)

HDS-9A
630-680

Total Pressure, psig
Space Rate, LHSV (Vol.)
Charge Rate, Gal./Hour

3000
0.3
0.8

Gas Recycle, SCF/Bbl.
H₂ Bleed Rate, SCF/Bbl.

4000
115

PRODUCT PROPERTIESSample Designation

Phase II, Item 002
Sun 0005

ASTM TestDesired

D1319 Aromatics, Vol.%

20-25

23.4

D86 Distillation, °F
10%
End Point

425 max.
500

364
502

D93 Flash Point, °F

140-155

140

D287 Gravity, °API

30-48

34.1

D2386 Freeze Point, °F

-51 max.

-70

D1322 Smoke Point, mm

19 min.

11

Source: Ref. 3-18

TABLE 3-24

OIL DERIVED FROM COAL

Comparison of Fuel Properties

Requirement	Boiler Navy Distillate Fuel Spec MIL-F-24397	COED NSRDC Full Range	COED NAVSEC PHILADIV Topped
Viscosity, CS at 100° F	10.0 Max.	4.50	8.0
Ash, %	0.01 Max.	0.01	0.007
Pour Point ° F,	+25 Max.	-5	+20
Flash Point ° F	150 Max.	58	160
Explosiveness, %	50 Min.	-	-
Water & Sediment by Centrifuge, %	0.02	0.30	-
Sulfur, %	1.3 Max.	0.2	0.16
Carbon Residue, 10% Bottoms, %	0.4 Max.	0.65	-
Corrosion, Copper Strip, 212° F,	2 Max.	4	2
Emulsion Characteristics Minutes,	20 Max.	120	-
Neutrality	Neutral		
Distillation			
10%, F	500 Max.	292	409
50%, ° F	644 Max.	540	580
90%, ° F	740 Max.	727+	780
95%, ° F	765 Max.	-	-
End Point, ° F	-	-	--
Vanadium, PPM	0.5 Max.	<0.1	<0.1
Cetane Number,	39 Min.	29*	27.7*
Gravity, ° API	27 Min	23.1	18.4
E.P. Properties, Scar Dia., mm	0.55	0.392	0.511
* Cetane Index			

Source: Ref. 3-7

TABLE 3-25

JET A FUEL FROM SHALE OIL--INSPECTIONS

			PARAHO SHALE OIL		TOSCO SHALE OIL		GARRETT (OCCIDENTAL) SHALE OIL	
		ASTM	RUN 11B (1500)	RUN 111 (800)	RUN 17B (1500)	RUN 113 (800)	RUN 103 (1500)	RUN 115 (800)
SPEC.		STANDARD	BLENDED FUEL	BLENDED FUEL	BLENDED FUEL	BLENDED FUEL	BLENDED FUEL	BLENDED FUEL
AROMATICS, FIA (VOL.%)	MAX. 20	D 1319	15.3	21.2	5.4	18.6	10.5	20.1
OLEFINS, FIA (VOL.%)		D 1319	1.8	1.3	1.3	0.4	0.4	1.2
AROMATICS, M.S. (WT.%)			16.4	24.7	8.8	21.4	12.1	
BROMINE NO. (CG BR/GM)			0.31	0.17	0.16	0.39	0.42	0.38
ANILINE PT. (°F.)		D 611	153.5	139.3	161.5	147.9	157.3	145.3
DISTILLATION (°F) INIT.	REPORT	D 86	374.	328.	342.	338.	345.	321.
10%	MAX. 400	D 86	397.	376.	369.	368.	383.	377.
20%			411.	396.	384.	382.	399.	400.
50%	MAX. 450	D 86	437.	442.	423.	431.	439.	448.
90%			475.	488.	490.	493.	484.	499.
FINAL	MAX. 550	D 86	490.	505.	512.	511.	502.	517.
RESIDUE (%)	MAX. 1.5	D 86	1.6	1.5	1.7	1.5	1.5	1.5
LOSS (%)	MAX. 1.5	D 86	0.4	0.5	0.3	0.5	0.5	0.5
ELEMENTAL ANALYSIS								
CARBON (WT.%)			-	86.12	85.96	85.63	85.07	86.34
HYDROGEN (WT.%)			13.45	13.02	13.87	13.41	13.58	13.41
NITROGEN (WT.%)			0.0024/0.0036	0.24	0.0063	0.0170	0.0030	0.0052
SULFUR (WT.%)	MAX. 03	D 1266	0.0004	-	0.0009	0.0012	0.0004	0.0019
FLASH POINT (°F)	MIN. 105	D 93	151.	132.	138.	136.	140.	128.
FREEZE POINT (°F)	MAX. -36	D 2386	-34.6.	-31.	-29.2	-29.2	-29.2	-22.8
GRAVITY 60°F (°API)	39-51	D 287	43.3	42.0	46.6	44.3	44.2	42.5
SPEC. GRAVITY (60/60°F)	0.775-0.830	D 287	0.8094	0.8157	0.7946	0.8050	0.8051	0.8134
SMOKE POINT (MM)	MIN. 25	D 1322	27.3	20.9	34.0	24.9	26.9	20.2
VISCOSITY, -30°F (CS)	MAX. 15	D 445	12.4	17.2/GEL	9.6	GEL	11.6	CRYSTAL

Source: Ref. 3-19

TABLE 3-26

SYNTHETIC JP-4 (WIDE-CUT) AVIATION TURBINE FUEL BLEND
FROM GARRETT (OCCIDENTAL) SHALE OIL

RUN NO.	<u>404</u>
Total Pressure, PSIG	2200
LHSV	0.48
<u>ASTM Distillation</u>	
IBP	246
5 Percent	275
10	296
20	332
30	383
40	434
50	453
60	463
70	470
80	476
90	486
95	494
FBP	500
Density, GMS/CC @ 60°F	0.7956
<u>Mass Spectroscopy</u>	
Paraffins	49.2
Monocycloparaffins	33.8
Dicycloparaffins	9.3
Tricycloparaffins	<u>1.7</u>
PARAFFINS, Total	<u>94.0</u>
Alkylbenzenes	5.1
Indans	0.7
Indenes	0.0
Naphthalenes	<u>0.0</u>
AROMATICS, Total	<u>5.8</u>
Sulfur, Total Wt. Percent	0.0056
Nitrogen, Total Wt. Percent	0.0027
JFTOT, Spun Tube Deposit Rating, °F	>500

Source: Ref. 3-19

TABLE 3-27

JP-4 FROM TOSCO SHALE OIL--INSPECTIONS

	<u>SPEC.</u>	<u>ASTM STANDARD</u>	<u>RUN 17B (1500) BLENDED FUEL</u>	<u>RUN 113 (800) BLENDED FUEL</u>
AROMATICS, FIA (VOL.%)	MAX. 25.0	D 1319	3.4	11.3
OLEFINS, FIA (VOL.%)	MAX. 5.0	D 1319	0.2	0.2
AROMATICS, M.S. (WT.%)			8.5	17.3
BROMINE NO. (CG BR/GM)			0.15	0.31
ANILINE PT. (°F.)		D 611	148.0	106.5
DISTILLATION (°F.) INIT.	REPORT	D 86	231.	231.
10%	REPORT	D 86	262.	254.
20%	MAX. 290	D 86	281.	270.
50%	MAX. 370	D 86	325.	322.
90%	MAX. 470	D 86	439.	426.
FINAL	REPORT	D 86	478.	471.
RESIDUE (%)	MAX. 1.5	D 86	1.8	1.5
LOSS (%)	MAX. 1.5	D 86	0.7	0.5
ELEMENTAL ANALYSIS				
CARBON (WT.%)			-	85.77
HYDROGEN (WT.%)			14.25	13.05
NITROGEN (WT.%)			0.0062	0.0093
SULFUR (WT.)	MAX. 0.40	D 1266	0.0003	0.0005
FLASH POINT		D 93	~ 60.	~ 75.
FREEZE POINT	MAX. -72	D 2386	-69.7	-76.
GRAVITY 60°F (°API)	45-57	D 287	52.7	52.7
SPEC. GRAVITY (60/60°F)	.8 OZ--.751	D 287	0.7681	0.7682
SMOKE POINT (MM)		D 1322	37.1	29.9
VISCOSITY, -30°F (CS)		D 445	3.4	3.3

3-55

Source: Ref. 3-19

TABLE 3-28

JET A FROM H-COAL LIQUID--INSPECTIONS

	<u>Spec.</u>	<u>ASTM Standard</u>	<u>Run 209 (1500) Blended Fuel</u>	<u>Run 304 (800) Blended Fuel</u>
Aromatics, FIA (vol. %)	Max. 20	D1319	18.5	37.4
Olefins, FIA (vol. %)		D1319	0.8	1.6
Aromatics, M.S. (wt.%)			20.4	41.6
Bromine No. (cg Br/gm)			0.18	0.39
Aniline Pt. (°F)		D611	115.8	76.9
Distillation (°F) Init.	Report	D86	340	347
10%	Max. 400	D86	369	372
20%			381	384
50%	Max. 450	D86	410	410
90%			454	456
Final	Max. 550	D86	476	480
Residue (%)	Max. 1.5	D86	1.5	2.0
Loss (%)	Max. 1.5	D86	0.5	0.0
Elemental Analysis				
Carbon (wt. %)			86.73	87.91
Hydrogen (wt.%)			12.66	11.70
Nitrogen (wt. %)			0.0047	0.0027
Sulfur (wt. %)	Max. 0.3	D1266	0.0016	0.0006
Flash Point	Min. 105	D93	134	138
Freeze Point	Max. -36	D2386	-47	<-94
Gravity 60°F (°API)	39-51	D287	35.7	30.7
Spec. Gravity (60/60°F)	0.775-0.830	D287	0.8464	0.8724
Smoke Point (mm)	Min. 25	D1322	17.97	9.71
Viscosity, -30°F (cs)	Max. 15	D445	9.35	9.36

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TABLE 3-29

JP-4 FROM H-COAL LIQUID--INSPECTIONS

	<u>Spec.</u>	<u>ASTM Standard</u>	<u>Run 209 (1500) Blended Fuel</u>	<u>Run 304 (800) Blended Fuel</u>
Aromatics, FIA (vol. %)	Max. 25.0	D1319	16.5	23.8
Olefins, FIA (vol. %)	Max. 5.0	D1319	0.9	0.4
Aromatics, M.S. (wt. %)			19.4	30.4
Bromine No. (cg Br/gm)			0.15	0.19
Aniline Pt. (°F)		D611	98.1	80.6
Distillation (°F) Init.	Report	D86	190.	205.
10%	Report	D86	226.	239.
20%	Max. 290	D86	245.	256.
50%	Max. 370	D86	306.	302.
90%	Max. 470	D86	380.	370.
Final	Report	D86	427.	422.
Residue (%)	Max. 1.5	D86	1.2	1.5
Loss (%)	Max. 1.5	D86	0.3	0.5
Elemental Analysis				
Carbon (wt. %)			85.84	87.18
Hydrogen (wt. %)			14.29	12.61
Nitrogen (wt. %)			0.0024	0.0026
Sulfur (wt. %)	Max. 0.40	D1266	0.0011	0.0003
Flash Point		D93	<40.	<40.
Freeze Point	Max. -72	D2386	<-94.	<-94.
Gravity, 60°F (°API)	45-57	D287	44.0	42.5
Spec. Gravity (60/60°F)	.802-.751	D287	0.8062	0.8134
Smoke Point (mm)		D1322	21.56	17.49
Viscosity, -30°F (cs)		D445	3.07	2.82

3-57

Source: Ref. 3-19

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4. PRIME MOVER - FUEL INTERACTION

J. Percival

This section is concerned with interrelationships between fuels and engines (prime movers). However, there are other components of any transportation system and it is the interrelationships among all of the components of the system that determine its practicality, cost, performance, and merits relative to alternative systems. Moreover, the relative importance of the constraints applying to different components of the given system vary with transportation mode. For example, a high power/weight ratio is of paramount importance to aircraft systems but relatively unimportant in large marine vessels. Also, auxiliary equipment such as required for fuel preparation is practical aboard ship but impractical or problematic on aircraft or small ground vehicles. And, as a third example, some pipelines require pumping stations that can operate with a minimum of direct human attention and maintenance thereby placing a premium value on simple, trouble-free systems. In this section, such considerations will only be mentioned briefly. However, in some cases, this may be of controlling importance.

The role of the fuel in transportation is that it shall release its heat of combustion and that heat shall be transferred to a working fluid which can be expanded through an engine to convert a reasonably high percentage of the input heat (usually between 25 and 40%) to work. This work is applied as reactive thrust in jet aircraft, applied to the turning of wheels or screws in the rail and marine transportation, or applied to the shaft of a pump or compressor for pipeline movements.

Both the fuel itself and its products of combustion come in contact with parts of the engine. Impurities such as ash and sulfur can cause deposits or corrosion and may shorten its working life or cause increased maintenance costs relative to operation on a cleaner fuel. Physical properties such as freezing point and viscosity can affect the movement of the fuel through filters and spray pattern of burners and injectors, and thus interfere with the completion of combustion.

Various chemical species burn in different ways which may be characterized as:

- speed of combustion
- temperature of self-ignition in air
- spark energy required to ignite a mixture of fuel vapor with air
- delay period between injection of fuel droplets into hot compressed air, and the commencement of ignition
- luminosity of the resulting flame.

These properties can make a fuel very suitable for one type of engine, and yet quite unsuitable for another. The clearest example of different combustion behavior is seen between high octane number gasoline which is excellent for the spark ignited Otto cycle, and diesel fuel oil made from petroleum distillate and characterized by a good cetane number.

The combustion properties which are looked for in these two fuels are almost diametrically opposed. In essence, the gasoline is required to mix readily with air prior to admission to the engine. It must then resist the heat generated during compression without self igniting. Upon application of the spark it should burn in a controlled fashion, producing the required pressure rise to drive the engine but without detonation. A satisfactory diesel fuel on the other hand is one which self ignites readily and quickly upon admission (as a spray under pressure) to the hot compressed air produced by the compression stroke. The rate at which it burns is controlled thereafter, not so much by its chemical properties as by the rate of admission and duration of injection, that is by outside mechanical controls.

The various hydrocarbon species exhibit in general either good octane number properties or good cetane number properties, never both.

	<u>Good Octane Components</u>	<u>Good Cetane Components</u>
Normal paraffins		X
Iso paraffins	X	
Olefins	X	
Aromatics	X	

4.1 Diesel Engines

The diesel engines used in non-highway transportation, notably in railroads and ships are not as critical of fuel chemistry as the smaller, higher speed truck and automobile diesel engines. That is because there is more time for fuel to ignite and burn out within a stipulated range of crank angle with the slower speed engines, than with the high speed engines.

Marine diesel engines, particularly the slow-speed engines successfully consume blends of heavy petroleum distillate with 80% or more of residual fuel oil with an asphaltic content of some 10% (4-1). Such fuels cannot be rated by the standard laboratory engine procedure which determines cetane number only down to a minimum of 38. However, the engine builders, after observing the ignition delay of such fuels in the large engine, and on comparing this with what they observe in the same large engines with clean distillate fuels, describe the behavior of the heavy fuel as equivalent to about 25 cetane

number. A clean distillate fuel for marine service shows close to 40 cetane number, and the lighter distillates used in trucks show mostly 45 and sometimes higher. Thus, a good cetane rating, while directionally preferred, is not always mandatory for large marine diesel engines.

Similarly, railroad locomotives have been operated successfully on highly aromatic fuels made from tar sands (4-2), fuels with cetane numbers too low to be rated on the standard engine procedure, but having a probable rating in the vicinity of 30 cetane, possibly 28.

Both the slow-speed marine engines and the locomotive engines discussed in this context owe much of their success to the fact that they are practically never called upon to start on the low cetane fuel. Ships are started, stopped and maneuvered on a separate supply of good cetane number fuel of the distillate type, and locomotives are frequently kept with engines running practically all their lives. While this may sound wasteful, the fuel consumed in 12 hours idling is only 5.5% of that which is consumed during the other 12 daily hours of working (4-18). It is therefore feasible to consider fuels of very poor cetane number for diesel engine operation, as long as some provision is made for starting and stopping on a better fuel, or for never stopping.

Cetane number is different from octane number in this respect. An Otto engine requires some minimum octane number but derives no benefit if it receives fuel of higher octane number, at least not until it is tuned by spark advance to take advantage. A diesel engine needs some minimum cetane number especially at the moment of starting when conditions for autoignition (temperature and pressure of the compressed air) are least favorable.

If supplied with fuel having a higher cetane number than this minimum, engine performance may be improved particularly in terms of the engine's ability to start under cold conditions or at high altitude.

Fuels made from shale, or from coal by Fischer Tropsch synthesis may be expected to have good cetane properties and to be more fully compatible with the diesel engines used at sea and on the railroads. Other more aromatic fuels that can be expected from other coal liquefaction processes are not necessarily excluded, provided they are upgraded. The engine builders are studying, and are anxious to study such fuels further, but are hampered in their development work by a shortage of the tonnage samples which they will need.

The diesel engine, in the sizes which are applicable to off-highway transportation have shown themselves to be tolerant of metallic impurities in the fuel up to an ash content of 0.1% mass, though special features such as water cooled valves have been employed to withstand aggressive attack from vanadium compounds which are a frequent constituent of residual petroleum fuels. A primary requirement of the diesel engine is that the fuel shall pass the close tolerances of the fuel handling equipment, pump and injectors, without producing too rapid wear, and shall be well atomized as it passes from the injector into the combustion chamber. With "dirty" fuels the clean-up is accomplished usually by centrifuging enroute to the engine, and viscosity control at the injectors is obtained by preheat. Both of these features may be considered state of the art.

The expressions "clean" and "dirty" fuels as used here are those which are common to the petroleum industry, namely a "clean" fuel is one which has been completely distilled whereas a "dirty" fuel is one which contains a proportion of undistilled residue and therefore has a content of asphaltic material plus ash. It is of course possible for a "clean" fuel to become contaminated with water, sand, rust, etc., but in general these can be relied upon to settle out of a distillate fuel by gravity alone.

4.2 Gas Turbines

Gas turbines are much more demanding of fuel quality, and as a general rule, the more efficient the gas turbine is made, the cleaner the fuel has to be. Cleanliness in particular means an absence or near absence of sodium and potassium contaminants, and a control of the amount and nature of other ash forming constituents such as vanadium, nickel, lead, calcium, rust and silicates. The points of principal vulnerability in the gas turbine are the first row stators (nozzles) and the first row blades (buckets). In this area, hot combustion gas at turbine inlet temperature encounters metal (often specially coated) which must resist oxidation, sulfidation (from alkali metal sulfates) and deleterious effects by corrosion, erosion and deposition from other ash forming impurities.

The ongoing development of the gas turbine, which is aimed to permit an increase in turbine inlet temperature from the current 2000-2200°F to ultimately 3000°F or 3500°F, is very largely concerned with furnishing these vulnerable blades with enough cooling and surface protection to permit them reasonable life within the high temperature environment. It is not envisaged that these developments toward high temperature and high efficiency will permit the use of fuels with more than a trace of ash.

Accordingly, synthetics like liquid hydrogen, the alcohols, methane and low contaminant distillate fuels could be used for high efficiency gas turbines. Among these methane and clean distillate fuels are well proven at today's inlet temperatures and sufficient testing has been done with hydrogen and methanol to show their suitability. Ammonia has likewise been demonstrated successfully (4-3).

Modifications of the fuel handling equipment, pumps and flow dividers are needed to accommodate fuels of low viscosity, and preheating together with the use of air blast nozzles will be required to obtain a 20 centistoke (or lower) atomizable fuel at the burners when high viscosity fuels are used.

These modifications, or at least similar ones, are supplied routinely today, because gas turbines are handling a range of liquid fuels from a light gasoline type (naphtha) with viscosity about 0.6 cs/100°F, up to heavy waxy gas oils which need preheat up to 170°F. Even more highly viscous fuels have been used, including some residual petroleum fuels with considerable ash (4-4) content. In this latter case the fuel has to be desalted by a water wash and inhibited with magnesium additive in the ratio 3 Mg/l vanadium by mass to prevent corrosion and deposits on the critical blades. Even with this fuel

treatment it is customary not to fire with turbine inlet temperature any higher than 1750°F, which corresponds to an efficiency about 27% on net heat content of fuel, and peak power about 10% less than would be obtained from the same engine on clean fuel with turbine inlet temperature at 1850°F. Because of the total ash which remains in the fuel after washing, and which is of course increased in mass by the magnesium additive (though thereby rendered much less corrosive), turbines fired on residual fuels are normally shut down for one day every two weeks to have deposits washed from the blades.

It must be pointed out that the experience which has been gained with gas turbines on these relatively dirty fuels is for applications in the 25,000 HP and higher range. Although the use of such fuels in gas turbines restricts the efficiency obtainable from the gas turbine itself, such units can be combined with waste heat boilers and steam turbines to bring the total efficiency to over 40%. Thus, if the size is suitable, a combined cycle residual fuel burning gas turbine installation could match an alternative diesel plant in efficiency, fuel costs and maintenance costs (4-5). However, applications of these principles to date have been to large stationary plants mostly above 100,000 HP.

Low viscosity liquid fuels which lack lubricity could cause wear problems with the fuel divider. The fuel divider is a device which meters equal rates of fuel to each combustor in a multicom combustor array, to insure that the turbine inlet temperature is even around the whole circumference of the first blading.

A special problem that has to be overcome with liquid hydrogen if used in aircraft turbines, is the development of a reliable pump that will be light enough and small enough in physical size to be incorporated into the aircraft. This has been identified as the only real remaining technical requirement associated with hydrogen as a fuel for aircraft, and one which should be fairly easily developed (4-6).

The ultra-clean liquid fuels which have a high latent heat of evaporation like methanol or are supplied refrigerated like hydrogen can help provide some of the blade cooling and may permit turbine inlet temperatures (and thus efficiency) to be raised higher than would be possible with more conventional fuels.

An important warning (4-7) has been voiced in connection with methanol, concerning its possible contamination with salt water. Sodium contamination even at a concentration of one part per million of fuel can be very damaging in causing sulfidation of blade material. Operators pay great respect to sodium contamination whatever the fuel; contamination by sea water is avoided wherever possible, and when it does occur, adequate centrifuging, washing or settling time is provided to remove it. The particular fear with methanol is that it would dissolve the aqueous part of the seawater and leave the salts in a very finely divided solid state which might be impossible to settle, and which could not be washed out because of the complete miscibility of methanol with water. Ethanol would have this same potential hazard.

However, if these alcohols are transported by pipeline or other land-based means of transportation this concern should not arise. Tanker or barge movements over salt water would call for special care to avoid sea-water contamination.

4.3 Free Piston Engine

The free piston engine converts its fuel to combustion gas in what is essentially a diesel cycle and then presents this gas to a gas turbine for expansion and conversion to useful work. The highest temperatures occur in a water cooled cylinder between opposed pistons and thus the free piston engine is tolerant of dirty fuels to about the same extent that the diesel is, namely up to 0.1% of ash and possibly higher with modification.

The companion gas turbine (4-8) is not as vulnerable to blade corrosion, oxidation or deposit formation as is a gas turbine fired directly with fuel. That is because the inlet temperature at 900-1000°F is much lower than the 1800°F and upward temperatures employed with open cycle gas turbines. Thus the combination of a diesel cycle gasifier and companion gas turbine has the capability of burning many kinds of fuels. It appears to be more widely omniverous than the diesel engine itself in that the combustion characteristics of the fuel, particularly cetane number are much less important. This is because the work developed in the free piston diesel cycle is stored (albeit very temporarily) as potential energy in a hot compressed gas. It is not taken out mechanically by linkage to the moving pistons. Very high compression ratios are possible and ignition delay and time of burning are not critical provided only that the fuel can ignite and can burn out substantially within the combustion cycle. Free piston engines are providing electric power in some of the Caribbean islands and parts of Africa.

A 5000 HP installation was tested extensively in the ship "William Patterson" in 1962 (4-9). An efficiency of 27% was found which could have been improved in several ways by use of exhaust heat. The principal finding was that "the maintenance hours required were materially greater than those for a steam turbine installation of the same size and somewhat higher than those for a residual fuel burning diesel installation." Much of the difficulty was associated with lubrication problems and broken rings. This particular engine consisted of half a dozen gasifiers producing about 1250 HP each feeding to a common turbine. The author of the reference (4-9) concluded that if a higher horsepower unit were required, it would be provided by increasing the number of gasifiers, rather than their size which would increase the labor costs further above those for alternative plants, steam or diesel. That is to say the labor costs of the latter two would not escalate much with size, whereas the free piston case would.

This observation was made at a time when ship's fuel was much lower in price than it is today. There is some cross-over point at which the relatively expensive maintenance would be justified in terms of monetary saving on the fuel, if such a fuel saving could really be made. Stated more precisely, the differential in costs between a fuel which is satisfactory for diesel operation and some lower quality fuel which would satisfy the free piston engine, would have to cover both the expected higher maintenance and the lower efficiency of the latter.

Up to now diesel engines, at least in the marine transportation size and speed, have shown themselves capable of running on the lowest cost liquid fuels available. For this reason the free piston engine has not been able to show enough edge over a diesel engine to enable it to grow in market size. If lower cost fuels become available which cannot be employed by diesels, the free piston could become a more serious contender than it has been to date. The principal idea here is that if certain liquids derived from coal, having perhaps very low cetane numbers, burn out to be poor in diesel operation the possibility remains that they might be used in free piston engines.

4.4 Otto Cycle Engines

Otto cycle engines, either spark ignited or pilot ignited (dual fuel diesel/gas engine) have to date been restricted to pipeline pumping in the non-highway transportation sector, and methane has been the principal fuel employed. To achieve efficiency, these engines are of high compression ration, about 13:1 and fuel of high octane number is essential to their use under that condition. Methanol, ethanol and hydrogen are clearly candidates, requiring very little modification of existing designs. However, in the case of hydrogen unless it is intended to run on a very lean mixture, there are problems of pre-ignition or flash-back to be overcome (4-10). This tendency comes not from octane number deficiency per se, but from the remarkably small spark energy needed to fire a near-stoichiometric hydrogen/air mixture. Very careful containment of the lube oil by multiple oil rings has been found effective. The purpose of this approach is to minimize formation of pyrolytic carbon deposits on piston and cylinder walls which can act as unclection centers for pre-ignition. Water injection has been used to control the problem, and spark plugs are generally of the colder type with smaller spark gaps, with well shielded leads to prevent spurious induced electrical discharge across the gap. Exhaust gas recycle suppresses pre-ignition and back-flash by slowing the movement of the flame front, but at the expense of efficiency.

Alternative ways of using hydrogen in compression ignition engines (diesel cycles) have been studied. However, none has really been successful and the modifications which have been introduced have actually converted the diesel cycle into an Otto cycle. Reference (4-11) studied a dual-fuel operation in which a very small amount of pilot fuel (diesel oil) representing less than 5% of the fuel rate needed for full power was used to ignite a compressed air hydrogen mixture. Knock-free operation could be obtained only between narrow limits of hydrogen/air mixture. Ignition failure occurred if the hydrogen were less than 22% of stoichiometric, and knock set in at mixture strengths above about 50% of stoichiometric.

Reference (4-12) describes a hybrid engine called CFI (cylinder fuel injection). This proposed engine is not a true compression ignition engine, since it requires a source of ignition. The hydrogen would be injected as a gas under pressure after the air intake valve had closed with a view to avoiding backfiring. Furthermore the low charge density limitation which is an inherent property of hydrogen/air mixtures when fed pre-mixed to the intake, and which is in part responsible for the lower volumetric power output of hydrogen relative

to gasoline, would be overcome. In short, the authors consider this approach to be the one most likely to yield high efficiency and high power together, in other words to allow hydrogen to approximate the role of a diesel engine fuel. It is not considered possible for hydrogen to be used without an external source of ignition since such operation would require a compression ratio of about 80:1.

4.5 Externally Fired Engines

The only point of interaction of fuels with externally fired engines such as steam turbines, Stirling engines and closed cycle gas turbines is at the boiler or fired heat exchanger where the heat of the combustion gases is transferred through tubing to boiler water, air, hydrogen or helium, whatever the working fluid may be.

Accordingly, there is a wealth of useful experience among the boiler manufacturers, as to the materials which are required and the geometrical spacings permitted in the several parts of the equipment. These include the combustion chamber, superheater, steam generating tubes, economizers and air preheaters. Maximum and minimum metal temperatures have to be controlled, and arrangements made to blow deposits off the surfaces. The most vulnerable metal is usually that in the superheater where heat transfer from one gas (the combustion gas) is made to another (the dry superheated steam). The designers are concerned with the amount of ash in the fuel, and with the chemical properties of the ash which determine how badly it is likely to foul surfaces, and to what extent it may be corrosive to metal. Inasmuch as boilers have not been produced with outstanding success to burn all types of coal and lignite, the heaviest types of petroleum fuel and all kinds of waste products, the use of some fuels which could be contemplated for these externally fired engines, will have to be studied carefully. There is still much research going on in the area of understanding slagging and fouling. Mine wastes and fines with 50% ash and high moisture are examples of troublesome fuels. Closed cycle gas turbines have operated for many years successfully on lignite (4-13).

Design differences for different fuels revolve generally around the combustion volume which is needed for complete burn out and the relative areas receiving heat transfer by radiation and by convection. The coals and heavy petroleum fuels transmit more heat by radiation than does natural gas for example. Ultra clean fuels like hydrogen and methanol which burn with flames of low luminosity would require the most heat transfer be accomplished by convection. The design principles are not well understood which would permit adequate design for any fuel. Most design data are based on empirical data and new fuels sometimes create problems. In addition to slagging problems created by some coals, the properties of fly ash which could affect resistivity, and thus particulate removal capability, are not completely understood. There is a limit to the range of fuels which any single boiler of given design can accept. Power station boilers are generally designed to operate on at least two fuels, e.g., coal or oil, oil or gas, but their design efficiency is highest on the principal fuel, and suffers slightly when operated on the secondary stand-by fuel. On the other hand, if a boiler has to be made to accept a range of fuels, it may have to be designed at some sacrifice of efficiency, and may suffer from control problems if the feeds are quite different. Examples, however, can be found in the steel industry where coal,

coal tar, petroleum, coke oven gas and blast furnace gas are fired to the same boiler, usually two at a time, sometimes all together. As with the design of heat exchange surface, the design of burners for any available fuel can be considered state-of-the-art.

4.6 Fuel Cells

The only fuels which are seriously contemplated for use in fuel cells in the near and medium term, are hydrogen and methanol. Of all fuel cell systems the most highly developed are those employing aqueous phosphoric acid electrolyte and supported noble metal catalysts. The hydrogen can be contaminated with CO₂ but CO must be held at less than 0.3 percent.

Cells with aqueous base electrolyte require fuel which is free of CO₂, at least down to a few parts per million.

Cells with molten carbonate electrolyte operating at temperatures above 1100°F can consume CO and therefore would be tolerant to hydrogen fuel made on-site, for example from a carbonaceous source such as coal.

Solid oxide cells operate at temperatures near 1800°F and are usable in principle with a wide variety of feedstock. However, their development is very slow due to their being several basic problems with materials.

It would appear then, that near-term application of hydrogen to non-highway transportation, using fuel cells and DC motors, will require very pure hydrogen (4-14).

4.7 Unconventional Fuel-Prime Mover-Combinations

This review has not touched all the possible combinations of fuels and prime movers, and the interactions which could occur. Some combinations are clearly not necessary to consider. For example, coal/oil slurry is entirely incompatible with the fuel cell and with spark ignited Otto engines. Among the unconventional combinations which have been tried, the literature shows the following.

<u>Fuel</u>	<u>Prime Mover</u>	<u>Reference</u>
Powdered coal and coal/oil slurry	Diesel engine	4-15 4-16
Ammonia	Gas turbine	4-3
Coal	Gas turbine	4-17 4-13

The coal fired gas turbine shows good promise if the coal is burned in a fluidized bed, because the particles emitted from such beds are soft and friable, rather than vitreous like the ash particles which come from coal fired directly into a refractory lined combustor. Strimbeck (4-17) indicates that the particle content of gas going to the turbine inlet must be less than

20 ppm by weight, a figure which could not be approached in that work with centrifugal separators following the combustor. Frass (4-13) indicates less than 1 ppm solids to be desirable and calls for a maximum particle size of 6 micrometers. It is recognized that blades are more tolerant of particles when wheel tip speed is reduced (e.g. from 1100 feet/second to 800 feet/second). However such a modification calls for a larger machine with twice as many turbine stages as are used at the higher tip speed.

Alkali metal contamination would probably limit the turbine inlet temperature to below 1600°F and the author concludes that the closed cycle gas turbine is a better proposition for use with coal.

The ammonia fired gas turbine is reported to need a larger combustor than one fired with natural gas. There is a power increase available (reported as 10-20%). The efficiency remains practically identical with that obtained on other fuels.

The two references (4-15), (4-16) may be said to have proved that the diesel engine can be made to run on coal, but in both cases there was a significant loss of efficiency and operating problems. Marshall (4-16) employed a fairly dilute slurry, 15% of solvent refined coal ground to 2 micrometers. Even with that careful preparation, the conventional fuel injection system plugged in short time.

4.8 Fuel and Maintenance Costs

In closing this section, a few words might be said about the relative costs of fuel and maintenance based on published experience with various types of conventional fuels. Generally, engine maintenance costs are much lower than fuel costs, so that an economical case might frequently be made to live with the costs of increased maintenance, if this permits the use of a lower cost fuel.

This point has been made in the discussion of the free piston engine versus the diesel. Such considerations must be tempered by the need for reliability. Maintenance takes time and calls for scheduling, as well as money.

An interesting example in which an extra maintenance burden is accepted in order to enjoy lower fuel costs comes from the adaptation of a stationary gas turbine to burn a residual bunker fuel.

This involves:

1. washing the fuel and inhibiting against vanadium (fuel oil treatment)
2. acceptance of somewhat increased maintenance of the gas turbine itself.

Reference (4-5) indicates a cost equivalent to 30¢/million Btu for the total ownership; operation and maintenance of the fuel oil treatment equipment, with a high vanadium content in the fuel (200 ppm), a fixed charge rate of 18% and 4000 operating hours per year on the gas turbine. With more operating hours and/or less contamination in the fuel this cost would drop in

proportion, for example to 10¢/million Btu at 100 ppm vanadium and 7000 h/yr operation.

Incremental turbine maintenance is also about 10¢/million Btu maximum, for a total maintenance cost of 20-40¢/million Btu of fuel above that which would be incurred if the turbine were operated on a clean fuel like natural gas or petroleum distillate.

Thus a price differential of the order 25¢/million Btu between the two classes of fuel, clean and dirty would make this relatively complicated maintenance procedure commercially viable.

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5. REVIEW OF POTENTIAL FOR ALTERNATE ENERGY FORMS FOR NON-HIGHWAY TRANSPORTATION

E. W. Nicholson
E. N. Cart, Jr.

In considering the various energy forms that may have a potential use in non-highway transportation, there are three forms which are considered in this section. First, is the possible applications of fuel cells in all four modes. Second, is the use of nuclear power, and third, a brief discussion on the use of solar-thermal and solar-electric forms.

5.1 Possible Applications of Fuel Cells (E. W. Nicholson)

In considering alternate fuels for non-highway transportation uses in the future, it is appropriate to assess the possibilities of utilizing fuel cells in these applications. Synthetic fuels are necessarily going to be more expensive than petroleum and natural gas fuels have been in the past, and therefore the fuel costs will be a higher percentage of the total annualized costs of the propulsion systems. Since fuel cells are not subject to Carnot cycle efficiency limitations, they theoretically can be operated at higher thermal efficiencies than can heat engines, such as combustion turbines and diesel engines. Thus it may be that fuel cell systems could be operated at lower annual costs, including fuel, than other types of prime movers.

A great deal has been written about the prospects for fuel cells in many applications, including vehicles, small and moderate sized power generation and utility power generation. (5-1,2,3,4,5,6) The potential for high thermal efficiencies has been especially emphasized. Other advantages of fuel cells stated are:

- They are clean, quiet and have little effect on the environment.
- They have very flat efficiency/load curves over the full range of operation and follow changes in load readily.
- The fuel cells themselves are modular in nature, so that there is a relatively small effect of capacity on cost down to small system capacities; systems can readily be enlarged in capacity by adding modules, and individual modules can easily be replaced when failures occur without shutting down the entire system.
- The systems could potentially be low cost when mass production of modules to meet high demand rates becomes possible.

Originally demonstrated by Grove in 1839, using hydrogen and oxygen, little was done with fuel cells until F. T. Bacon in England developed a high-current-density cell operating on hydrogen and oxygen in 1932. A large amount of work was carried out by industrial concerns in the 1950's and 60's, including Union Carbide, General Electric, United Technologies, Allis-Chalmers, Exxon, Leesona-Moos, Westinghouse and others. (5-7) Many of the organizations discontinued work when the difficult technical problems encountered resisted solution.

The first practical use of fuel cells occurred in connection with the space program in the U.S. in the 1960's utilizing fuel cells produced by GE and UTC which operated on pure hydrogen and oxygen. These, however, were too expensive to consider for normal terrestrial applications. In 1967, serious interest developed among gas utilities and, in 1972, among electric utilities in possible application of fuel cells in their systems. UTC and Exxon carried out work on such systems, (5-8,5-9) and the UTC phosphoric acid system has been carried to the point of construction of a 4.8 megawatt demonstration unit (5-35) which will be installed in the Consolidated Edison system in New York City. UTC has also built 12-40 kW units, originally for the gas utilities and designed to operate on natural gas. (5-5)

5.1.1 The Fuel Cell System

In a fuel cell, illustrated in Figure 5-1, a fuel and an oxidant are fed continuously to the cell and the oxidation of the fuel is carried out electrochemically, so that the heat of oxidation is released as electrical energy. This electrical energy is in the form of low-voltage direct current. A number of cells ordinarily are connected in series internally (bipolar construction of the cells) or externally (monopolar cells) to provide up to 3000 volts DC from a system. (5-35) This power output can be inverted to alternating current and transformed to higher voltages in a power conditioning stage. However, in applications of fuel cells to non-highway transportation, the direct-current output of the fuel cell stacks or modules can be utilized without inversion to drive direct-current motors. This would save a significant amount of investment cost and some loss of efficiency otherwise encountered in power conditioning.

At the present time, the only practical fuel cells known require hydrogen or H_2/CO mixtures as fuel feed to the cell itself. Direct feeding of methanol to a fuel cell has been demonstrated, (5-10) and it has been shown that a fuel cell can be run on direct feeding of light hydrocarbons, (5-11) but such cells so far have required uneconomically large amounts of platinum catalysts on the anodes. Hence, all fuel cells of commercial interest incorporate a fuel preparation and conditioning section preceding the fuel cell modules, unless pure hydrogen can be used as the feed. This fuel preparation and conditioning section will normally include a steam reformer to convert the original fuel (hydrocarbon distillate, methane, methanol, ethanol, etc.) to hydrogen and CO, followed by a shift converter to convert CO to H_2 and CO_2 , and, when necessary, equipment to remove the CO_2 . With hydrocarbons the steam reformer would operate at 1400-1800°F, while for methanol the reforming temperature would be between 350-400°F.

FIGURE 5-1

SCHEMATIC DIAGRAM OF A FUEL
CELL WITH ACID ELECTROLYTE

Source: 5-17

Furthermore, it is important to note that sulfur level in fuel cell fuels is a very important factor. Sulfur poisons the catalysts used in the fuel processing operations, and sulfur content of the feed to the steam reformer must be kept below 0.1 part per million (ppm). This is normally accomplished by including a hydrodesulfurization unit followed by a zinc oxide bed to remove the H_2S formed before the steam reformer. Such equipment will handle sulfur contents in feeds of up to about 1000 ppm; light distillates from coal liquefaction may be available with sulfur contents below this. Methanol would not be a problem in this respect. It is desirable, however, to be able to use heavier and higher-sulfur feeds for fuel cells, in order to provide greater fuel flexibility. UTC has been carrying out some promising development work on "autothermal" reforming,⁽⁵⁻³⁷⁾ involving introduction of air along with the feed and steam to the reformer. With this process, they have been able to reform No. 2 fuel oil containing 2500 ppm of sulfur; the resultant H_2S in the gas stream from the reformer must be reduced by scrubbing to the level that can be tolerated by the fuel cells. Depending on the type of fuel cell employed, sulfur content of the hydrogen actually entering the fuel cell may have to be in the range of 1 to 200 ppm.

In addition, facilities for maintaining water balance, temperature control, electrolyte quality and control of electrical output may be necessary.

Thus, a total fuel cell system may include the various sections shown in Figure 5-2. The cost of the fuel cell modules themselves is not necessarily the major item in the total cost.

5.1.1.1 Types of Fuel Cells

A number of different types of fuel cells have been investigated, and these can generally be classified on the basis of the types of electrolytes utilized.

In general, the higher the pH of the electrolyte, the higher will be the net voltage obtained from the cell and, therefore, the higher the power efficiency of the cell. Voltage and efficiency also increase with temperature.

Concentrated solutions of alkalis, such as KOH, are the most desirable electrolytes, and fuel cells of this type were used on satellites with pure H_2 and O_2 feeds. With more practical feeds, however, such as hydrocarbon distillates, methanol or coal, and using air as the oxidant, CO_2 will get through to the electrolyte and precipitate carbonates. Therefore, extraordinary efforts must be made to exclude CO_2 from the feed streams into the fuel cell, or the electrolyte must be reconditioned on a regular basis; both of these expedients add cost.

As a result, major efforts have gone into developing systems that reject CO_2 continuously by their nature. Exxon investigated alkaline electrolytes buffered with bicarbonates so that they would reject CO_2 , but efficiencies were lower than desirable.⁽⁵⁻¹²⁾ The most promising systems so far are the aqueous phosphoric acid^(5-8,5-36) and the molten carbonate

GENERALIZED FUEL CELL SYSTEM

electrolyte(5-13,5-37) systems under development by United Technologies Corp. (UTC). Exxon studied the economic possibilities of large fuel cell systems for utilities based on KOH electrolytes in which CO₂ in the fuel and air feeds was completely removed by treating, but concluded that more research was needed to achieve the target fuel cell performance level before development work on such a system was justified.(5-9) Westinghouse has worked on a system utilizing a solid electrolyte (doped zirconia) operated at around 1800°F which can handle mixtures of H₂, CO and CO₂, but the difficult materials problems involved have not yet been resolved.(5-14) General Electric developed a fuel cell based on a solid polymer electrolyte which was successfully used in the Gemini spacecraft with pure hydrogen and oxygen, but costs of solid electrolyte, catalysts, and other critical components so far are too high for this cell to be potentially competitive in commercial applications.(5-15) The Department of Energy has an active program seeking practical advanced fuel cell systems.(5-16)

5.1.2 Fuel Cells to Consider for Non-Highway Transportation Applications

5.1.2.1 1978-1985 Period

The only fuel cell that can be considered in the 1978-85 time period for use in non-highway transportation applications is the phosphoric acid electrolyte system being developed by UTC.(5-8,5-36) None of the others is far enough along in development to achieve commercialization by 1985. A 4.8 MW phosphoric acid based unit,(5-35) however, is currently being prepared for a demonstration in the Consolidated Edison system in New York City under a program jointly sponsored by UTC, Consolidated Edison, the Department of Energy and EPRI. This demonstration unit is expected to be in operation in the last half of 1979.

The phosphoric acid fuel cell operates at 375°F and can convert hydrogen produced from hydrocarbon distillates or methane feeds to direct current electricity with an overall efficiency of about 41% (lower heating value basis).^{*} The Consolidated Edison demonstration unit will be operated initially on a naphtha feed with a maximum of 500 ppm of sulfur. Other fuels, such as hydrogen, methanol or ethanol can be used with easier operations in the fuel processing section and higher overall efficiencies. On pure hydrogen feed, UTC estimates 50% efficiency currently, with 55% available from future systems.(5-17) If the "autothermal" reforming system being developed by UTC(5-37) proves successful, heavier and higher-sulfur hydrocarbon distillates may be usable as fuels. Sulfur in the feed to the fuel cell itself may be as high as 200 ppm, but CO must be below 1%. Life of the fuel cell modules of over 10,000 hours has been demonstrated, and it hoped that 40,000 hours can be obtained longer range. The fuel processing section and other auxiliary facilities should be operable over a nominal 20 years or more life.

^{*} All thermal efficiencies in this section are on the lower heating value basis.

The weight and volumetric energy densities of fuel cell systems have not been well established yet because most of the intensive efforts so far have been in connection with utility-type installations where these considerations are not particularly significant. For mobile applications, it will be necessary to undertake careful and innovative design studies directed toward packaging the entire fuel system with minimum weight and volume. During a workshop at Los Alamos Scientific Laboratory in August, 1977 directed toward potential applications of fuel cells in vehicles, it was estimated that phosphoric acid fuel cells operating on methanol feed (relatively easy processing requirements) and producing DC power (no inverter) might reach 30 pounds/kW and 1 cu. ft./kW.⁽⁵⁻¹⁸⁾ The fuel cells being considered, however, were of about 10 kW size, and units in the 2 to 60 megawatt size range which would be applicable to locomotives, ships and pipelines should have better energy densities.

5.1.2.2 1985-2000 Period

It is possible that either or both of the molten carbonate and the KOH electrolyte system with clean-up of feed streams could be commercially available in the 1985-2000 time period. This assumes there are applications in which these fuel cells would have competitive advantages large enough to justify spending the considerable amounts of money that would be required to complete the research and development work still remaining to be done.

The molten carbonate fuel cell utilizes a mixture of alkali metal carbonates as the electrolyte and operates between 1100 and 1300°F, and at 150 psia pressure.^(5-13*,5-37) No noble metal catalysts are required on the electrodes. This fuel cell can achieve overall thermal efficiencies on methane, methanol, or hydrocarbon distillates to DC power of about 50% at full load or 53% at part load. The molten carbonate fuel cell cannot operate on a pure hydrogen feed or hydrazine because CO₂ is required for reaction at the cathode; if pure hydrogen or hydrazine were fed, an extraneous CO₂ feed to the cathode would have to be provided. Sulfur in the feed to the fuel cell itself probably will have to be below 10 ppm.⁽⁵⁻³⁸⁾ High CO concentration is acceptable.

The alkaline (KOH) electrolyte fuel cell would be the preferred system if hydrogen or hydrazine are useable as fuels. The air, of course, would have to be scrubbed free of CO₂. With hydrogen and air, a KOH fuel cell should achieve 60% efficiency. On pure hydrogen and oxygen, UTC projects 75% efficiency with alkaline fuel cells based on their satellite-type units,⁽⁵⁻¹⁷⁾ but these are uneconomic for commercial use. With hydrocarbon distillates, methanol or methane, which would have to be reformed, shifted and treated intensively for removal of essentially all CO₂ and H₂S, overall thermal efficiencies should be around 55%. The development of process equipment which could be incorporated into mobile fuel cell systems and which would adequately remove CO₂ within economic constraints will be a difficult job. The energy densities of Exxon thin-cell fuel cells with KOH electrolytes

* This report is concerned with operation of molten carbonate fuel cells in conjunction with coal gasification to produce the feed, but the fuel cell sections would be comparable.

are estimated to be 6.3 lb./kW and 0.44 cu. ft./kW for a 10 MW module, not including the fuel or air processing equipment or power conditioning (inversion, etc.).(5-9) This fuel cell operates at 195°F and is constructed using light-weight and low-cost plastic elements.

None of the other fuel cell systems that have been under investigation appears worthwhile considering in this study. The high-temperature (1800°F) solid electrolyte (doped zirconia) system, even if it were commercialized, would not be practical in non-highway transportation applications. As pointed out earlier, the solid polymer electrolyte system still has serious cost problems, and it is not being actively developed at the present time.

Of course, an advanced system of superior characteristics might be developed by 2000 or after as a result of the research programs being sponsored by the Department of Defense and EPRI. Since these systems are not yet specifically defined, it is not possible to consider them in this study.

In all cases of applications of fuel cells to mobile operations, questions of the resistance of the systems to vibration, tilting, shock, etc. will have to be investigated. None of these problems seems insurmountable. Fuel cells did withstand the shocks of launching of satellites for space applications.

5.1.3 Applicability of Fuel Cells to Non-Highway Transportation Systems

5.1.3.1 Aircraft

Fuel cells will probably always have much too high a weight-to-power ratio for application to aircraft. For example, the following tabulation compares weights for the engines and fuel required for a Lockheed Electra turboprop with the weights that would be involved in a comparable airplane powered by fuel cells and DC motors. The Electra requires 15,000 HP at takeoff and 11,800 HP for cruise. In the tabulation, it is assumed that fuel cells and motor installed power need be only that for cruise, and that the extra power for takeoff can be provided by short-time overloads.

Weights, pounds	<u>Turboprop</u>	<u>Fuel Cells + Motors</u>
Engines	7,300	
Fuel Cells		52,200
DC Motors		153,000
Fuel	<u>32,500</u>	<u>18,000</u>
TOTAL	39,800	223,200

Thus it is seen that the weights of the fuel cells and motors alone are more than five times the weight of the turboprop engines and fuel in the case of the Electra, even though the fuel efficiency of the Electra is only 23% and the fuel cell efficiency might be twice that. The weight shown for the fuel cells is based on the light-weight construction assumed for the Exxon KOH electrolyte system⁽⁵⁻⁹⁾ and includes only the cell module weight, excluding the weights of fuel processing and conditioning equipment. Indeed, even this weight of the cell modules alone, without considering the weight of motors, fuel and other equipment, is shown to be greater than the weights of turboprop engines and their fuel.

In view of the above comparisons, no further consideration will be given to the use of fuel cells in aircraft.

5.1.3.2 Railroad Locomotives

Diesel-electrics predominate the locomotive market in the United States. At the beginning of 1978, 99.3% of the 27,669 locomotives owned by Class I railroads were diesel-electrics, and the rest were straight electric locomotives operated off catenaries.*⁽⁵⁻¹⁹⁾ The following tabulation shows a breakdown of locomotives by services for 1974, the latest year for which such data are available:⁽⁵⁻²⁰⁾

<u>Service</u>	<u>Locomotives in Each Service</u>		<u>Percent of Total of Type</u>
	<u>Number</u>	<u>Percent</u>	
Freight			
Diesel-electric	22,374	99.3	80
Electric	162	0.7	75
Passenger			
Diesel-electric	657	93.5	2
Electric	46	6.5	21
Switching			
Diesel-electric	4,894	99.9	18
Electric	7	0.1	4
Totals			
Diesel-electric	27,925	99.2	99.2
Electric	215	0.8	0.8

Diesel-electrics also account for the bulk of the energy consumed by locomotives:**⁽⁵⁻²¹⁾

* Actually, there were 11 steam locomotives owned by Class I railroads as of 1/1/78, but these were in only nominal service. There were 225 "slave" units in service in conjunction with diesel-electrics in 1974. These are separate units with motor-driven wheels the power for which comes from the diesel-electric locomotive; they provide extra tractive force.

**Data are for 1973.

<u>Service</u>	<u>10¹² Btu/yr</u>	<u>Percent</u>
Freight		
Diesel-electric	508	99.2
Electric	4*	0.8
Passenger		
Diesel-electric	11	89.4
Electric	1.3*	10.6
Switching and Work Trains		
Diesel-electric	56	99.9
Electric	0.04*	0.1
Totals		
Diesel-electric	575	99.1
Electric	5*	0.9

* In terms of primary energy utilized in generating electricity (33% efficiency) and allowing for distribution losses (15%).

It can also be seen from the above tabulation that freight services require 89% of the total energy consumed by the railroads, and switching operations take almost 10%. Passenger services (long-line) consume only 2%. This does not include local and commuter passenger services, which consume another 10.2×10^{12} Btu/year, 95% of which is in the form of electricity to operate electric-powered cars.

In view of the above information, primary consideration of the possible use of fuel cells in railroad locomotives will be based on a comparison with diesel-electrics in freight service, although some consideration will be given to diesel-electrics used for switching.

A summary of the horse-power ranges of all locomotives currently in operation is as follows: (5-21)

<u>Horse-Power Range</u>	<u>Percent</u>
700-1400	20
1500-1850	35
2000-2800	24
3000-3600	20
4000-5000	1

For long-line freight operations, the predominant sizes of locomotives being used are in the 3000-3600 HP range, and most of the locomotives in switching service are 1000 to 1400 HP.(5-21) The bulk of the orders from railroads for freight locomotives currently are for 3000 HP units, although 3600 HP units are available.

5.1.3.2.1 Characteristics of Diesel-Electrics

A diesel-electric locomotive consists basically of a large diesel engine with 16 to 20 cylinders which drives a generator to produce direct-current power. This DC power is distributed to series-wound DC traction motors at each wheel. In newer models, however, AC generators, or alternators, are being used in order to overcome the maintenance problems associated with the commutators and brushes required in DC generators. The AC current produced is rectified by solid-state units to provide the DC power for the traction motors.(5-21)

A 3300 HP (at the wheels) diesel-electric locomotive weighs 390,000 pounds, including 4000 gallons of fuel. The engine and alternator for this locomotive weigh 59,500 pounds. Based on an 85% efficiency from the engine output to the wheels, this represents a weight to power ratio of 15 lb./HP or 20 lb./kW. The corresponding volumetric ratios are about 0.3 cu. ft./HP or 0.4 cu. ft./kW.

5.1.3.2.2 Possibilities for Fuel Cells

It is not inconceivable that the above ratios could be achieved with fuel cells. As pointed out earlier, the Fuel Cell Powered Vehicle Workshop at Los Alamos in August, 1977 concluded that fuel cells including fuel processing equipment but with no power inversion facilities should be possible with 30 lb./kW and 1 cu. ft./kW ratios.(5-18) But, in this case, small units of only about 10 kW were being considered; the 2900 kW units required for a locomotive of this type should have much better power densities. For example, the power densities of the 10 MW fuel cell trailer in the design study on KOH electrolyte fuel cells Exxon Enterprises did for EPRI(5-9) were 6.3 lb./kW and 0.44 cu. ft./kW. These values do not include the weight and volume required for the fuel processing section. Further study will be needed in order to reach a more definitive conclusion regarding the technical feasibility of substituting fuel cells for the diesel engine-alternator-rectifier system in present-day diesel-electric locomotives.

A fuel cell system probably cannot be appreciably larger in volume than the present diesel-electric power equipment for the same horsepower rating because the overall dimensions of existing large diesel-electric locomotives are near the limits as constrained by tunnel and bridge clearance, radius of curvature of tracks, etc. on existing railroads. Space within the existing locomotive envelopes is already well utilized by required equipment and facilities. Improved fuel efficiency in a fuel cell powered unit could make additional volume available for the fuel cell by reducing the size of the fuel tank.

The allowable weight of a fuel cell system for the required power output needs to be studied further because a number of factors are involved which are associated with the design of the locomotive. One of these factors is "adhesion" between the drive wheels and the rails. Some locomotives are provided with ballast over some of the axles to improve adhesion. It seems possible that, in a modular fuel cell system, some of the fuel cell weight could be distributed to take the place of ballast, thus providing more allowable weight for the fuel cells.

In present locomotive design, the total load-pulling capacity, or tractive effort, is limited by the current-handling capability of the traction motors. More horsepower on board a given locomotive could, however, be used to operate the train at a higher speed. This could have a net economic advantage to the railroad.(5-21) Even though the average daily speed of freight trains is only about 20 miles/hour (allowing for idle time waiting for reassembling of trains, switching, etc.), (5-22) the railroads seem to have little inclination to go to higher horsepower locomotives, as stated earlier.

Another aspect relating to adhesion could prove to be beneficial for fuel cell systems. In a diesel-electric locomotive, when slippage between wheels and track occurs for the limiting axle, power to all the axles must be reduced until the slippage stops. On electric locomotives with power from catenaries, control systems are possible so that power needs to be reduced only to that axle where slippage is occurring. It seems possible that a similar control system could be provided with fuel cells; since the system is modular in nature, separate power takeoffs could be arranged for various groupings of modules.

Fuel cells could have a significant advantage in fuel efficiency. The overall fuel efficiency of a diesel-electric when operating on productive load over an average load cycle is about 37%.(5-21) But, diesel engines are most susceptible to damage, and thus increased maintenance costs and downtime, when they are being started up, as temperatures equalize; during this time, coolant and lubricant flows must be carefully monitored. In addition, the coolant is subject to freezing in cold weather. For these reasons, diesel-electric locomotives are generally kept running at idle continuously when they are not in load service, or in the shop for service. Road engines generally operate at idle 45-55% of the time, and switch engines 77%. For the road engines, the fuel consumed during idling amounts to about 6% of the total consumption, and reduces the overall fuel efficiency to about 33%. It is possible, however, that diesel efficiencies could be increased in the future through incorporation of bottoming cycles.

Fuel cell systems have been demonstrated to be easily and quickly started up and shut down, so continuing to run them at idle would not be necessary.* Assuming a 40% fuel efficiency can be obtained with a phosphoric

* The fuel reforming section would probably be maintained at temperature except for idling periods of greater than about 4 hours.

acid fuel cell system, and naphtha can be used as fuel, as shown in Table 5-1, this would reduce the fuel requirement on board the 3300 HP locomotive being considered from 4000 gallons to 3670 gallons, or a saving about 5400 pounds of weight and 45 cu. ft. of volume on board the locomotive, as well as reducing the operating costs for fuel.

Of course, the critical question is whether or not a fuel cell system could be economically competitive with diesel-electrics in railroad service. This is discussed in another section. It appears worthwhile to consider both the phosphoric acid fuel cell system for the 1978-85 period, and the molten carbonate system for later application. It is also conceivable that a KOH electrolyte system could be utilized if a feasible means can be devised to remove CO₂ from the fuel and air streams to the fuel cell.

5.1.3.3 Marine

The marine industry serving United States trade is very diverse, consisting of a number of different types of vessels to handle the various requirements. The marine industry may be characterized as follows⁽⁵⁻²³⁾:

- Foreign Trade

Liners (common carriers providing scheduled service; includes break-bulk, containerships, ships providing for roll-on/roll-off of cargo, and barge carriers.)

Tramps (irregular service and charters)

Dry Bulk Carriers (bulk cargoes such as grains and ores)

Tankers (liquid bulk cargoes such as crude petroleum, refined petroleum products, chemicals, edible oils)

Passenger (cruises and trans-ocean service)

- Great Lakes

Dry Bulk Carriers (ore, coal, etc.)

Tankers

Tugs, Package Freighters, Car Ferries

- Coastal

Tankers (mostly clean petroleum products between East, West and Gulf Coast Ports)

Tugs and Barges (oil and dry bulk commodities)

TABLE 5-1FUEL CELL POWER FOR A LOCOMOTIVE

<u>Power Source</u>	<u>Diesel Electric</u>	<u>H₃PO₄ Fuel Cell + Reformer</u>
Fuel	Distillate	Naphtha
Vol. Power Density-ft ³ /kW	0.4	1
Weight Power Density-lbs/kW	20	30
Efficiency - %(a)	33	40
<u>Fuel on Board (3300 HP Locomotive)</u>		
Gallons	4000	3670
Cubic Feet	535	490
Pounds	28000	22600

(a) Based on output of prime mover, less requirement for locomotive auxiliaries.

- Inland Waterways

Towboats and tugboats (pushing or pulling barges loaded with bulk liquid or dry cargoes (petroleum products, chemicals, coal, ore, etc.))

- Offshore

(Vessels engaged in the discovery and recovery of petroleum in offshore areas; includes drilling rigs, exploration craft, tugs, supply craft, construction and pipelaying vessels)

- Pleasure Craft (inboard and outboard motor driven)

- Fishing and Miscellaneous

(Commercial fishing boats and miscellaneous harbor service craft)

Booz-Allen & Hamilton carried out extensive studies for the Department of Energy on the marine transportation industry. (5-23, 5-24, 5-25) They developed information on the types of vessels and the power sources for the various sectors of the industry, and estimated the fuel consumed in each service for 1974, the latest year for which such information was available. They also estimated the increases in power levels that will probably occur in each type of vessel by the year 2000, and the probable fuel consumptions in that year. A summary of this information is given in Table 5-2.

It will be seen from the table that the foreign trade sector consumes by far the largest fraction of all fuel utilized by the marine industry: 80% in 1974 and an estimated 84% in 2000. However, the bulk of the fuel consumed by this sector is purchased outside the United States. Only 7% of nearly 4800 vessels engaged in U. S. foreign trade are American flag ships. The fuel purchased by this sector in 1974 is shown below: (5-23)

Registry	Point of Purchase			
	United States		Overseas	
	10 ¹⁵ Btu	%	10 ¹⁵ Btu	%
U. S.	0.090	43	0.125	57
Foreign	0.350	16	1.795	84
Total	0.440	20	1.920	80

In addition to the 0.44×10^{15} Btu of marine fuels purchased in the U. S. in 1974 by the vessels engaged in foreign trade, another 0.37×10^{15} BTU of fuel was purchased in the U. S. by the other sectors of the marine industry. This was a total of 0.81×10^{15} Btu out of the 2.9×10^{15} Btu for the industry, or 28%. Of the fuel purchased in the U. S., 72% was residual fuel, 17% diesel and 11% gasoline. Of the fuel purchased outside the U. S., 91% was diesel and the rest resid. (5-23)

TABLE 5-2

ENGINES AND FUEL CONSUMPTION IN VARIOUS SECTORS OF U. S. MARINE INDUSTRY

Service	Type Engine	HP Range	1974		2000		
			Energy Consumed		HP Range	Energy Consumed	
			10 ¹⁵ Btu/yr	%		10 ¹⁵ Btu/yr	%
<u>Foreign Trade</u>							
Liner							
Break-Bulk	Diesel	14,500	0.36	12	26,000		
Container Ships	St. Turb.	8,000-28,000	0.09	3	9,000-40,000		
Roll-On/Roll-Off	St. Turb.	11,000-25,000	0.06	2	22,000-36,000		
Barge Carriers	St. Turb.	32,000-36,000	0.02	1	35,000-39,000		
			0.53	18		1.25	19
Tramp	Diesel	5,000	1.08	37	7,000	2.47	37
Dry Bulk Carriers	Diesel	8,000-11,000	0.33	11	10,000-13,500	0.93	14
Tankers	Diesel	7,000-20,000	0.33	11	7,000-36,000	0.81	12
Passenger	St. Turb.	20,000-26,000	0.08	3		0.13	2
			2.36	80		5.60	84
<u>Great Lakes</u>							
Dry Bulk	St. Turb., Dies.	4,000-5,000	0.04	1.4	10,000	0.09	1.4
Other	Diesel	500-4,000	0.01	0.3	1,500-3,000	0.01	0.1
			0.05	2		0.10	1.5
<u>Coastal</u>							
Tankers	St. Turb.	12,000	0.07	2	12,500	0.14	2
Other	Dies., St. Turb.	2,000-6,000	0.04	1.7	2,200-22,000	0.11	1.7
			0.11	3.7		0.25	3.7
<u>Inland Waterways</u>							
Tow Boats/Tugs	Diesel	500-6,000	0.09	3	1,000-7,000	0.10	1.5
<u>Offshore</u>							
			0.06	2		0.20	3
<u>Pleasure Craft</u>							
			0.23	8		0.30	4.5
<u>Fishing and Misc.</u>							
			0.03	1		0.10	1.5
			2.93	100		6.65	100

5-16

Above 20,000 shaft horsepower (SHP), most of the vessels are powered by steam turbines with residual fuel fired to the boilers. Diesel engines are generally used for lower horsepowers; the smaller SHP engines have been fueled with distillate, but currently, especially overseas, the predominant choice is low-speed diesel engines utilizing the same residual fuel fired to steam boilers. These low-speed diesels get good efficiency and operate on the cheaper, more available residual fuel. They can be built up to 45,000 SHP, but delivery times are so long for such sizes that usually diesel installations are below 30,000 SHP. If the quality of the residual fuels available for marine use continues to deteriorate, ship operators may go back to the use of steam turbines for vessels above 20,000 SHP.

The Booz-Allen & Hamilton study also included information on power plants that could be available for the marine industry by 2000, including the projected fuel efficiencies, and this is summarized below: (5-24)

<u>Power Plant</u>	<u>Fuel</u>	<u>Efficiency, %</u>
<u>Current</u>		
Steam turbine with reheat steam (1450 psig, 950°F)	Resid	32-36
Low-speed diesel	Resid	39-41
<u>Future</u>		
Steam turbine with high pressure, high temperature reheat (2400 psig, 1050°F)	Resid	35-39
Adiabatic diesel	Diesel	49
Naval Acad. heat balance engine	Diesel	43
Heavy duty gas turbine, combined cycle	Resid	36-40
Closed cycle combustion turbine	Resid	40-41

Combustion turbines for powering ships have not been used significantly so far. Deterrents have included the need for clean distillate fuels and the inherent drop-off of efficiency at part load. Efficiencies of simple-cycle combustion turbines are not high (around 30%), but incorporation of a steam/turbine bottoming cycle (combined cycle) can increase efficiencies to 40% or more. Combustion turbines do have an advantage in providing low weight/SHP.

Work is being carried out to overcome the shortcomings of combustion turbines. Heavy-duty combined cycle units that can operate on residual fuel are being developed, as indicated in the tabulation above. Detroit Diesel Allison is developing a 7000 SHP simple-cycle combustion turbine for marine use which maintains essentially constant 30% fuel efficiency over the top 70% of its load curve. (5-26) United Technologies Corp. has been carrying out design studies for the Office of Naval Research to identify light-weight propulsion systems for high performance naval ships in the 20,000 to 200,000

SHP range. They have studied simple-cycle combustion turbines operating at higher gas inlet temperatures to achieve higher efficiencies, and closed-cycle turbines for which the heat is provided by an external heater fired with a hydrocarbon fuel or a nuclear reactor. They find that, with fossil fuels, the total engine-plus-fuel weight would be smaller for the simple-cycle case for short-endurance missions, and the closed-cycle would be lighter for long-endurance missions. The use of a light-weight nuclear heat source could make that case with a closed-cycle better than either of the fossil fuel cases for all missions.(5-27)

5.1.3.3.1 Possibilities for Fuel Cells

The only fuel cell system that could be commercially available before 1985 is the phosphoric acid system, and the overall efficiency of this system from fuel to DC electricity is projected to be about 40%. This would not have any advantage on a fuel consumption basis over the low-speed diesels already available, especially since the fuel cells would require a low-boiling, clean distillate fuel whereas the diesels can run on resid. As noted in the above tabulation, advanced diesel engines running on diesel fuel may be able to achieve efficiencies above 40%. Studies also have been made on the possibilities of utilizing a secondary, or bottoming cycle to produce additional useful energy from the hot exhaust gases liberated from the diesel engine. It is estimated(5-24) that 15-18% of the energy in the exhaust gases can be recovered in this way. This could provide at least part of the power required for ship services, and would result in an overall improvement in the efficiency of the diesel engine system.

On ships, especially tankers, that require steam for operations such as heating cargo or cleaning holds, there is an advantage for employing steam turbines and boilers. A fuel-cell-powered ship would have to have an auxiliary-fired boiler. In a diesel-powered ship, the heat in the exhaust can be used to generate steam for some of these needs. The fuel cells would directly provide the electricity needed aboard ship, whereas auxiliary generators are needed with diesels or steam turbines.

Because of maintenance problems with diesel engines, diesel-powered ships generally are equipped with a spare engine. Extra power is always needed in port to handle the loading/unloading operations, and extra engines are always provided for these purposes. On a small ship, there may be three engines: one for normal at-sea operation, another to be put on line for in-port duty, and one spare. A fuel cell power plant, being made up of a number of smaller modules, would not have as large a percentage of spare capacity.

With fuel cells, direct current motors would be necessary to drive the shafts, whereas only gear trains are required for diesels or steam turbines.

In the 1985-2000 period, molten carbonate fuel cells may be commercially available, and they could be feasible on large ships. With a potential efficiency of about 50%, such fuel cells might be economically

competitive. The use of fuel cells employing hydrogen or hydrazine as fuels have been suggested for marine use.(5-28,5-29,5-30) As shown in Table 6-1, the cost of hydrazine is expected to be at least six times that of liquid fuels from coal per million Btu's, so that it does not seem possible that a hydrazine-based fuel cell could ever compete economically with other prime mover systems. Liquid hydrogen cost from Table 6-1 is more than twice that of coal liquids. With hydrogen fuel, an alkaline electrolyte fuel cell could be used, which would be cheaper and of higher efficiency than those utilizing hydrocarbon fuels. No fuel processing equipment would be needed, but the air feed would have to be scrubbed to remove CO₂, and liquid hydrogen storage would be expensive and require additional volume compared with liquid hydrocarbon fuels, even with higher fuel efficiency. Use of gaseous hydrogen stored in metal hydrides is an alternative; gaseous hydrogen is about \$5/MBTU cheaper than liquid, but the cost of a metal hydride storage system is significant. An economic analysis of this situation would be necessary.

In view of the information presented in Table 5-2 and the tabulation of current and future efficiencies as well as the factors considered in the above discussion, a detailed investigation has been made on the economic feasibilities for fuel cells in marine applications. Two cases are covered: (1) a medium-sized vessel of about 7000 SHP normally powered by diesel engines, such as a small tanker or a tramp ship; and (2) a large vessel normally utilizing a steam turbine drive of around 40,000 SHP, such as an ultra-large tanker.

5.1.3.4 Pipelines

In the United States in 1975, there were 263,000 miles of natural gas transmission lines and 130,000 miles of trunk lines for long-distance movement of crude petroleum and petroleum products.(5-31) Assuming there is a pumping station about every 150 miles for the gas lines and every 40 miles for the oil lines, there would be about 5000 such stations in the United States. In 1970, which was about the peak period for gas and oil production in the U. S., 740×10^{12} Btu/yr were consumed in pumping natural gas, and 390×10^{12} Btu/yr for pumping crude and petroleum products.(5-32) These values were about 600×10^{12} and 235×10^{12} Btu/yr in 1976.

In the U. S., almost all the oil pipeline pumping is accomplished with AC electric motors fed from local electric utility grids. In the past, the pipelines obtained special low prices from the utilities for their power requirements because they provided an assured, steady load. Recently, however, the utilities have been increasing their prices to closer to the average residential rates. Even at these higher cost levels, it is unlikely that fuel cells could provide pumping power at lower cost than that available from the utility grids. Banks and Horton⁽⁵⁻³³⁾ describe as a major advantage of fuel cells for liquid pipeline pumping operations the fact that the speed of the DC motor drives could be easily varied as liquid throughput requirements varied by adjusting the output of the fuel cells. In current operations with constant-speed AC motors, throttling of the liquid flow is sometimes

necessary to control throughput, and this results in significant wastage of energy. However, AC motors are now becoming available that provide for controlled phase changing so that power, and therefore throughput, can be adjusted as desired. Also, variable-speed linkages can be provided between the motor and the centrifugal pump. On the other hand, some extra costs would be involved in using DC motors; because of the arcing inherent in commutated motors, which would be quite hazardous in the pump houses, some kind of protection would have to be provided around the motors. In view of the above factors, further consideration of fuel cells for use on oil pipelines is probably not justified.

For gas pipelines, at least 93% of the compression energy is supplied by gas taken from the pipeline.(5-32) Otto cycle, reciprocating engines are used to drive the compressors in about half the compressor stations today. These range in capacity from 1000 to 13,500 HP; about 70% are in the 1000-2000 HP range.(5-33) High efficiency is obtainable with such engines because of the high octane number of methane and the high compression ratios therefore usable. Prior to the Arab oil embargo, combustion turbines had been purchased for this service in increasing numbers because their lower maintenance requirements were able to offset the higher efficiency of the reciprocating engines, and their cost was less (average of \$219/installed HP vs \$295 for reciprocating machines). As gas prices increased in recent years, the combustion turbines were the first to be taken out of service in those lines where throughput declined. In an effort to reverse this trend, combustion turbine manufacturers have undertaken research and development programs to improve turbine efficiencies.(5-33)

Efficiencies of existing and possible future prime movers which can be utilized on gas pipelines are summarized below.(5-33,5-34)

<u>Prime Mover</u>	<u>Full-Load Efficiency %</u>	<u>Part-Load Efficiency %</u>
<u>Combustion Turbines</u>		
Older simple-cycle	20-25	
Newer simple-cycle	30-39	25-32
Simple-cycle with heat recuperation	34-35	30
Combined-cycle with steam bottoming (Existing)	39	32
(Future)	42	
Combined-cycle with organic bottoming	43	
Same with heat recuperation	47+	
<u>Otto Cycle Reciprocating Engines</u>		
Existing, new	31-39	
Combined-cycle with steam bottoming*	38-43	
Combined-cycle with organic bottoming*	39-45	

(Continued)

*Retrofit of bottoming cycles appears possible on existing machines.

<u>Prime Mover</u>	<u>Full-Load Efficiency %</u>	<u>Part-Load Efficiency %</u>
<u>Diesel Reciprocating Engines (Using Diesel Fuel)</u>		
Existing	35-40	
Combined-cycles with organic bottoming	46-50	

It is seen from the above information that equipment already exists which is about as efficient as the phosphoric acid electrolyte fuel cells are expected to be, and improvements to existing equipment are being studied which could bring efficiencies to the range anticipated for molten carbonate fuel cells. Fuel cells would have an advantage at part-load conditions, because their efficiency improves as load decreases, whereas combustion turbine efficiencies drop off sharply at part load. The Banks and Horton study(5-33) concludes, based on generalized considerations, that fuel cells are very promising devices for applications on pipelines. Their study, however, does not assess some of the limitations to fuel cells brought out in the earlier part of this section.

5.1.4 Conclusions

From the considerations discussed in this section, it may be concluded that there are some possibilities for applications of fuel cells in non-highway transportation, but more detailed studies and economic comparisons with probable improvements on existing systems on a total systems basis will have to be made to determine whether fuel cells could be practically viable and economically competitive in the future. The various fuels that will be available in the future will have to be considered for each type of prime mover. Undoubtedly, research and development efforts will be necessary on fuel cell systems, and the studies proposed will indicate where those efforts could best be directed.

The areas that seem most worthwhile studying in more detail are listed below. In general, comparisons of applications at the lower levels of power requirements will probably be more favorable to fuel cells because there is a larger reduction in cost per horsepower with increasing power level for the various heat engines than there is for fuel cells.

- Railroad locomotives

Comparison of fuel cells with diesel-electric drives for 3000-3600 HP road engine and 1500 HP switch engine.

- Marine

Comparison of fuel cells with 7000 HP diesel engine and with 30-40,000 HP steam turbine drives.

- Pipelines

Comparison of fuel cells with advanced combustion turbine combined-cycle systems and advanced reciprocating engines of about 5000 HP.

5.2 Nuclear

In addition to using nuclear energy to generate electricity or hydrogen, which can serve as energy carriers, nuclear energy is being used directly in marine transportation and has been seriously considered for aircraft application. The nuclear reactor is used to generate steam to drive a steam turbine in one case, and to preheat the air to high temperatures to drive a gas turbine in the other case. Theoretically, it is possible to use nuclear energy in railroads and pipelines, but the institutional problems would be greater than for the marine or aircraft application. The following sections will address the status and problems of direct use of nuclear power in each of the four modes of non-highway transportation.

5.2.1 Marine

Currently there are in excess of 200 operating nuclear-powered ships, with some of these having been in service for more than 20 years.(5-39) Almost all these are naval ships, but there have been two nuclear merchant ships built--the "Savannah" in the United States and the "Otto Hahn" in the Federal Republic of Germany. Also, a third non-military nuclear ship, the "Mutsu" has been built in Japan for use in government assignments.(5-39)

The "Savannah" was a 9830 deadweight ton vessel powered by a pressurized water reactor nuclear power plant. The vessel operated from 1962 to 1970. The service record of the nuclear propulsion system was nearly flawless (99.88% availability record) during its 500,000 miles of operation.(5-39)

The "Otto Hahn" is a 15,000 deadweight ton vessel that incorporates a more advanced nuclear propulsion system than the "Savannah." The "Otto Hahn" has been in service since 1968 and its nuclear plant has had one of the best operating records of any nuclear plant constructed in Europe.(5-39)

Based on the operating record of the "Savannah" and "Otto Hahn," together with the more than 200 nuclear naval vessels, it is clear that the technology exists today to produce nuclear-powered commercial vessels.

There are three major problem areas that have retarded the progress of nuclear-powered ships:

1. Economics
2. Indemnification and liability
3. Port entry and international clearances

5.2.1.1 Economics

As the situation exists now, the economic competitiveness of nuclear vessels over conventional vessels cannot be demonstrated with any real degree of confidence. Construction costs of a nuclear-powered ship are considerably higher than those for a conventional vessel, so that the economic incentive must come from the lower unit fuel cost of nuclear versus fossil fuel, to offset the carrying charges associated with the higher investment. Nuclear power plants, with lower unit operating costs, are generally more economically attractive than conventional power plants if the size and output of the unit is raised to a sufficiently high level. Thus, nuclear power would have the best opportunity to be economical in very large ship sizes. Huskisson of Lloyd's Register states, "The cost of nuclear propulsion seems to rise at almost the same rate as oil." (5-40) Thus, it is not clear when in the future nuclear-powered ships may be economical.

5.2.1.2 Indemnification and Liability

Liability coverage is also one of the major problems deterring commercial nuclear ship development. At present, sufficient liability coverage is not obtainable in the U. S. through the commercial underwriting markets to protect owners against claims by persons who may be injured or sustain property loss or casualty as a result of radioactive damage from a nuclear ship accident. (5-39)

The Price-Anderson bill, which provides U. S. government indemnity for land-based reactors does not apply to merchant vessels. The "Savannah" was covered by the Price-Anderson bill, but in 1974, the proposal to grant the same provisions to all merchant ships was dropped for legislative reasons. The "Otto Hahn" and the "Mutsu" are covered by combined commercial and government insurance. (5-39)

5.2.1.3 Port Entry and International Clearance

The third major obstacle to nuclear-powered marine vessels is obtaining clearance to dock in the U. S. and foreign ports. For the "Savannah" and the "Otto Hahn," port entry was obtained through government-to-government negotiation of bilateral agreements. (5-39) This is a time-consuming practice and impractical on a commercial basis.

Acceptance of nuclear-power vessels by a government does not necessarily mean that the ship could call at its ports. Pressure groups within a country could easily bar admittance. Considering the recent protest over land-based reactors which have occurred in the U. S. and other nations of the world, it seems reasonable to assume that mobile reactors in ships would be treated similarly.

In summary, the technology exists to build nuclear-powered merchant ships. However, it is not clear when nuclear-powered ships will become economical to fossil-fueled vessels. In addition, there are substantial non-economic problems to be solved before a nuclear merchant fleet becomes a reality.

5.2.2 Aircraft

Nuclear-powered aircraft have been explored in considerable detail since the 1950's. A schematic drawing of a nuclear aircraft power plant is shown in the figure below.

SCHEMATIC OF A NUCLEAR AIRCRAFT POWER PLANT

Source: Ref. 5-41

A major problem with nuclear-powered aircraft is the weight penalty associated with the reactor shielding to protect the crew and passengers. It appears that a nuclear-powered aircraft would require a take-off weight of perhaps 1.5 million pounds to carry a practical payload.(5-41) Because of the total power plant weight, it seems that the payload carrying ability would be comparatively small even though the large fuel weight requirement of conventional turbine engines has been eliminated.(5-42) The increased price of fossil fuels is a factor that should help the relative economics of a nuclear-powered aircraft. However, the cost of the nuclear power plant and fuel, and the cost of the airframe to carry the heavy power plant are such that it is not clear that there would be any economic gain. On the basis of available data, the high investment costs appear to outweigh the fuel cost savings.(5-42)

A recent study by Rand for the Air Force on very large military airplanes (VLA's) gives an indication of the cost of a military nuclear-powered aircraft compared to fossil-fueled planes with the same design payload (350,000 pounds). The fossil-fuel planes were limited to a range of around 6,500 nautical miles, while the nuclear plane would have essentially unlimited range. The following table compares the life-cycle cost estimate

for 112 unit equipment (U.E) aircraft (which could be interpreted as providing "equal capability" on the design-point mission) and include a representative peacetime utilization rate.

LIFE-CYCLE COST ESTIMATES
(BILLIONS OF 1975 DOLLARS)

<u>Alternative</u>	<u>Acquisition Cost</u>	<u>20 Year Operating and Support Cost</u>	<u>Total Life-Cycle Costs</u>	<u>Ratio to VLA-Syn JP</u>
VLA-Syn. Jet Fuel	15.5	16.4	31.9	1.0
VLA-Liquid CH ₄	16.5	18.8	35.3	1.11
VLA-Liquid H ₂	13.6	21.3	34.9	1.09
VLA-Nuclear	32.1	24.6	56.7	1.78

Source: 5-43

The absolute cost figures are not as meaningful as the ratio of the cost, which clearly show that a nuclear-powered aircraft is not economically attractive.

One of the conclusions from the Air Force study was that nuclear propulsion for aircraft was only attractive for station-keeping missions requiring large station radii (greater than 4,000 nautical miles). Thus it would appear that from a commercial standpoint, nuclear-power aircraft would not be economically attractive.

In addition to the economic factors, the environment and safety concerns of carrying a nuclear plant in an airplane, which might crash in populated areas, would seem to be almost an insurmountable problem to overcome. It would seem to be a safe guess that nuclear aircraft for commercial transport purposes will not be seen until sometime well after the year 2000, if at all.

5.2.3 Railroad and Pipeline

While it should be technically feasible to use nuclear power to generate electric power that could be used on board a railroad engine or at a remote pipeline pumping station, it would seem to be extremely unlikely that it would be either economical or practical. In general, nuclear power is potentially economical only for very large-size plants. On the scale envisioned for railroad or pipeline application, it would seem to be unlikely that nuclear power could compete with any of the other alternate fuels being considered.

The institutional problems to be overcome on using a nuclear reactor on board a railroad engine, that may derail in a populated area, would seem to be insurmountable.

5.3 Direct Solar Radiation

Direct solar radiation may be used to heat a working fluid that may be used to develop power in a heat engine. Thermal conversion may be divided into three levels: low temperature (225-250°F) used for solar heating, high temperatures (producing steam temperatures of up to 600°F by concentrating the sun's rays by use of reflecting surfaces), and ultrahigh-temperature (approaching 5000°F through the use of precisely controlled parabolic reflectors). Only the latter two areas would generate steam temperatures high enough to be considered for non-highway transportation. However, both systems require the use of reflectors which require a large area.

Another direct radiation method is the application of photovoltaic cells to convert sunlight directly to electric power. The amount of area of solar cells required for typical rail, marine, and pipeline applications are discussed in the following sections. The use of solar photovoltaic is not possible to even consider for aircraft application because of weight limitations and the impact of the solar cells on the aerodynamic behavior of the plane.

5.3.1 Marine

The average amount of solar power that falls on the earth during a 24-hour day at an average location is about 18.6 continuous watts/ft² (200 watts/m²). In some parts of the world, the rate will be considerably greater. The intermittent peak solar power falling on the earth is around 93 watts/ft² (1000 watts/m²), but due to the nature of solar energy, storage batteries must be used to store the electrical energy generated during peak hours. Thus, the annual average amount considered for this screening study is 18.6 watts/ft² (200 watts/m²). Since current photovoltaic collectors have efficiencies of around 10%, this means that the power collected is 1.9 watts/ft² (20 watts/m²) of collector area. The theoretical maximum efficiency is limited to about 20%.

To generate 10,000 SHP (continuously for 24 hours) would require about 4.2×10^6 ft² of collector surface if the photovoltaic efficiency is 10%. For a 485,000 deadweight ton tanker, the approximate deck area is only 0.24×10^6 ft². (5-40) Thus, it is clear to see the impracticability of using solar photovoltaics as an alternate energy form for marine application. Even at a 20% photovoltaic cell efficiency, it is still impractical.

5.3.2 Railroad

For a 3300 hp locomotive, a solar photovoltaic collector surface of 1.3×10^6 ft² would be required, assuming the average of 18.6 continuous watts/ft² (200 watts/m²) of solar power and a 10% collector efficiency. If one assumes the collector could be attached to the top of each locomotive and

freight car, then a 50-car train would be able to carry only $0.025 \times 10^6 \text{ ft}^2$ of collector area. Thus, it is not necessary to consider further the use of solar photovoltaics for rail use.

5.3.3 Pipeline

The size of pumps vary widely in the pipeline industry, but for illustrative purposes, it will be assumed that a 500 hp driver is required. The amount of collector area required assuming 18.6 watts/ft^2 (200 watts/m^2) and 10% efficiency) is about $0.2 \times 10^6 \text{ ft}^2$. This would require an area of about 5 acres for this 500 hp case. Again, in most cases this would be an impractical solution to the alternate fuel problem. In some isolated cases, the use of photovoltaic cells may be useful if the pumping station is very remote and the material being pumped cannot be used as a fuel in either a diesel or gas turbine.

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16. Abstracts <p>A planning study has been made for DOE on alternate fuels for non-highway transportation (aircraft, rail, marine and pipeline). The purpose of the study was to provide DOE with a recommendation of what alternate fuels may be of interest to non-highway transportation users from now through 2025 and to recommend R&D needed to allow non-petroleum derived fuels to be used in non-highway transportation.</p> <p>In the near term (present 1985), there is unlikely to be any major change in the fuels used in any of the four modes of transportation except that the average quality of the marine fuel is likely to get worse. In the mid-term period (1985-2000), there will be a transition to non-petroleum fuels, based primarily on shale oil derived liquids assuming a shale oil industry is started during this time.</p> <p style="text-align: center;">(over)</p>																				
17. Key Words and Document Analysis. 17a. Descriptors <table border="0"> <tr> <td>Alternate Fuels</td> <td>Free Piston Engine</td> </tr> <tr> <td>Marine</td> <td>Stirling Engine</td> </tr> <tr> <td>Aircraft</td> <td>Closed Cycle Gas Turbine</td> </tr> <tr> <td>Pipeline</td> <td>Physical Properties of Alternate Fuels</td> </tr> <tr> <td>Railroad</td> <td>Otto Cycle Engines</td> </tr> <tr> <td>Prime Movers</td> <td>Fuel Cells</td> </tr> <tr> <td>Diesel Engines</td> <td>Nuclear Power</td> </tr> <tr> <td>Gas Turbines</td> <td>Direct Solar Radiation</td> </tr> </table>					Alternate Fuels	Free Piston Engine	Marine	Stirling Engine	Aircraft	Closed Cycle Gas Turbine	Pipeline	Physical Properties of Alternate Fuels	Railroad	Otto Cycle Engines	Prime Movers	Fuel Cells	Diesel Engines	Nuclear Power	Gas Turbines	Direct Solar Radiation
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16. Abstracts (cont.)

The future outlook for possible prime movers and potential fuel sources for the long term (2000+) is as follows. In the marine area, steam engines burning coal or diesel engines with unrefined shale oil or coal slurries are the prime candidates. With the aircraft gas turbine, either synthetic liquids from shale or coal would appear to be the most desirable fuels. Railroads will probably remain with the diesel/electric prime mover using shale oil as a source of distillate. Pipelines will probably use electric motors as the major type of prime mover.

This Appendix covers the background information on the various prime movers, the physical property data, the fuel-prime mover interaction and a review of some alternate energy forms.

6. ECONOMICS OF FUEL MANUFACTURE

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6.1 Introduction and Overall Summary

The United States faces a serious energy problem with regard to petroleum and natural gas. These two fuels presently supply essentially all of the energy needs for non-highway transportation systems. One major consideration in evaluating alternative energy sources is fuel cost. This section deals with the economics of fuel manufacture. Analysis of alternative production routes for any particular fuel is performed when the information is available. Total costs excluding distribution are calculated as the sum of three factors:

- o Recovery of capital
- o Cost of feedstocks
- o Operating costs

The economic basis for these calculations is explained in Section 6.2.

The following alternate fuels are investigated:

- 1) Shale gasoline
- 2) Shale distillate
- 3) Coal gasoline
- 4) Coal distillate
- 5) Coal-in-Oil Slurry
- 6) Methanol
- 7) Hydrogen
- 8) Ammonia
- 9) Ethanol
- 10) Methane or Substitute Natural Gas
- 11) Oil from Organic Waste
- 12) Hydrazine
- 13) Acetylene
- 14) Methylamine
- 15) Low BTU Gas
- 16) Electricity

Fuel costs are developed from published literature. One problem with literature data is differences in economic bases, rates of return, plant sizes, etc. A common bases is needed for realistic comparison; the details of this basis are presented in section 6.2. A list of references is included as an attachment to this section.

The costs for the various fuels are shown in Figure 6-1 on the basis of dollars per million BTU (lower heating value*) with cost increasing from left to right. The shaded bar in Figure 6-1 represents the range of costs obtained from the literature. In some cases a single line is shown simply because only one estimate was located in the literature. Even with these fuels, there is uncertainty about the cost. For the purpose of this study, the relative cost, on a consistent basis, is more important than the absolute cost. The absolute cost will be uncertain until some of these plants are actually built and operating experience is obtained.

The same information is shown in Table 6-1 grouped into three cost categories, less than 10 \$/MBTU, 10-20 \$/MBTU, and greater than 20 \$/MBTU. Thirteen different fuels/energy carriers are projected to cost less than 10 \$/MBTU in terms of 1980 dollars. It must be stressed that this cost excludes distribution cost, and in the case of both hydrogen and methane, which will best find application in liquid form, the liquefaction cost. These costs are discussed in Section 7.

Another way to consider the same data is to look at the cost of fuels/energy source through the resource base used to produce the fuel. Information on this basis is shown in Figure 6-2. The shale resource base fuels fall in the 4-5 \$/MBTU range. Coal derived fuels cover a broad range, from 0.5 to 45 \$/MBTU. For the solar (biomass) resource most of the fuels are in the 8-16 \$/MBTU range.

Also, this information is examined by fuel produced. Costs on this basis are presented in Table 6-2. In the case of methanol, for example, coal appears to be the most economical resource base. Where a given fuel can be produced from either coal or biomass, the most economical resource base is coal.

* Lower heating value because the latent heat of vaporization of water is not generally recoverable with transportation fuels.

FIGURE 6-1
ALTERNATE FUELS COSTS

TABLE 6-1

COST OF ALTERNATE FUELS

<u><10 \$/MBTU</u>		<u>10-20 \$/MBTU</u>		<u>>20 \$/MBTU</u>	
Coal	0.9 -1.6				
Raw shale oil slurry	2.50-3.0			Methanol by	
Coal-in-oil slurry	2.55+	Methanol from coal	6.65-11.15	Pyrolysis of	} 20.75
Low BTU gas	3.65-4.25			Solid waste	
Shale syncrude	4.20-4.40				
Shale distillate	4.20-4.40	Methane from sewage algae	12.50	Ethanol by fer- mentation	21.20
Shale gasoline	4.90-5.20	Ammonia from coal	12.30-12.90	Methanol by OTEC	29.70
Coal liquids (syncrude)	3.75-6.30	Acetylene from coal	14.00	Hydrazine	>45
Methane from coal	6.10-8.75			Methylamine- coal*	>14
		Methanol from biomass	14.80		
		Ammonia from biomass	17.55		
Direct coal gasoline	4.85-8.40				
Direct coal distillate	5.35-9.00	Hydrogen by electrol- ysis	19.65		
Oil from organic waste	8.60				
Hydrogen from coal	7.90-9.60				

*Current raw material costs only; higher with addition of processing and investment costs.

FIGURE 6-2
COST OF ALTERNATE FUELS BY RESOURCE BASE

Table 6-2
Alternate Fuels Cost

	<u>Cost \$/MBTU (1980\$)</u>
Shale gasoline(1)	4.90-5.20
Shale distillate(1)	4.20-4.40
Coal gasoline(2)	4.85-8.40
Coal distillate(2)	5.35-9.00
Coal(3)-in-Oil Slurry	2.55+
Methanol	
o Coal(2)	6.65-11.15
o Biomass(4)	14.80
o Solid Waste Pyrolysis(4)	20.75
o OTEC(5)	29.70
Hydrogen	
o Coal(2)	7.90-9.60
o Electrolysis(6)	19.65
Ammonia	
o Coal(2)	12.30-12.90
o Biomass(4)	17.55
Ethanol	
o Fermentation (7)	16.75-21.20
Methane	
o Coal(2)	5.45-7.95
o Sewage Algae(4)	12.50

Table 6-2 (Cont.)

	<u>Cost, \$/MBTU (1980\$)</u>
Oil from Organic Wastes ⁽⁴⁾	8.60
Acetylene ⁽⁸⁾	14.00
Methylamine ⁽⁹⁾	> 14.00
Hydrazine ⁽⁹⁾	> 45
Low BTU gas ⁽¹⁰⁾	4.25
	<u>¢/kwh (1980\$)</u>
Electricity	
o Coal ⁽¹¹⁾ /Nuclear ⁽¹²⁾	3.00
o Solar ⁽¹³⁾	10.90

Notes: For Table 6-2

- (1) Produced by aboveground retorting.
- (2) Coal at 21 \$/Ton.
- (3) Coal at 8 \$/Ton.
- (4) Includes waste collection cost of 20 \$/Ton.
- (5) Ocean thermal energy conversion.
- (6) Current potassium hydroxide technology; about 13 \$/MBTU for developmental SPE process.
- (7) Corn at 3.75 \$/Bushel
- (8) Cost about the same for calcium carbide or coal arcing technology.
- (9) Current raw material costs only; higher with addition of processing and investment costs.
- (10) Coal technology; coal at 21 \$/Ton.
- (11) Steam-electric cycle; coal at 21 \$/Ton.
- (12) Light water reactor process.
- (13) Steam-electric cycle

6.2 Basis for Economic Evaluation

Realistic comparison of fuel costs requires a common basis. This is especially true when the information source is published literature which contains a large number of different bases. The bases chosen in this study are presented in Table 6-3.

The dollar basis year is 1980. Investments and operating costs obtained from the literature are escalated at 7%/year for the years preceding 1980. 100% equity financing is assumed and a capital recovery factor (CRF) of 0.2 \$/year per dollar of investment is chosen.

A CRF of 0.2 roughly corresponds to a 10% discounted cash flow (DCF) return. This return rate may be lower than the minimum acceptable to many companies today. Assumptions of project life, depreciation period, depreciation schedule, investment schedule and production rate all affect the CRF and Table 6-4 illustrates how changes in these variables affect CRF. CRF is also a function of DCF return level as illustrated in Table 6-5, which shows the CRF for DCF levels of 5%, 10%, and 15% using the assumptions of Case F, Table 6-4. A sample DCF calculation is shown in Table 6-6, using the assumptions presented for Case F, Table 6-4.

An alternative to 100% equity financing method is utility financing where a substantial portion of the investment is debt financed. This financing scheme generally permits a somewhat lower capital recovery factor because of the low equity fraction. Typical utility financing CRF's range from 0.155 to 0.17 based on the following:

- 1) Debt to equity ratio ranging from: 75/25 - 65/35
- 2) 9%/year interest rate on debt,
- 3) 15%/year return on equity,
- 4) 20 year project life.

Thus, a CRF of 0.2 represents the lower end of the acceptable industry return levels and is somewhat higher than typical utility recovery levels.

Table 6-3

Bases For Economic Evaluations - Task 2

- Money on 1980 dollar basis
- Assume 100% equity financing for fuel manufacturing
- Assume capital recovery factor of 0.2 (\$/yr per dollar investment)
 - This corresponds roughly to a 10% DCF return
- Assume cost escalation of 7%/yr prior to 1980, 5%/yr after 1980
- Investments based on U.S. Gulf location except for facilities which must be located in other regions.
- Investments include a 25% contingency factor.
- Plant size

SNG	250 MSCF/D
Liquids	50 kB/D
Hydrogen	880 MSCF/D
Low Btu Gas	1350 MSCF/D
Methanol	2000 Ton/D
Ethanol	1500 Ton/D
- Byproduct Prices

Sulfur	60 \$/Long Ton (2400 lbs.)
Ammonia	200 \$/Short Ton (2000 lbs.)
- Electricity Cost

3 ¢/kwh

- Mine-Mouth Coal Cost

High Sulfur (Eastern - underground mine)	- 21 \$/Ton
Low Sulfur (Western - surface mine)	- 8 \$/Ton

Table 6-4

CAPITAL RECOVERY FOR 10% DCF
EFFECTS OF SOME FACTORS

Case	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>	<u>F</u>
Project Life, Years	16	16	20	20	20	20
Depreciation Period, Years	16	16	16	16	16	16
Depreciation Type*	SL	SYD	SYD	SYD	SYD	SYD
Working Capital, % on Inv.	0	0	0	0	7.5	7.5
Startup Cost, % on Inv.	0	0	0	0	0	5
Production Rate, %						
Year 1	100	100	100	100	100	50
Year 2	100	100	100	100	100	87.5
Year 3 to End	100	100	100	100	100	100
Investment Schedule						
% in Year						
-2	0	0	0	15	15	15
-1	0	0	0	45	45	45
0	100	100	100	30	30	30
+1	0	0	0	10	10	10
Capital Recovery Factor	0.193	0.179	0.164	0.181	0.196	0.215

*Code

SL - Straight Line Depreciation
SYD - Sum of Yearly Digits

Table 6-5

CAPITAL RECOVERY COST FACTORS

<u>DCF Return</u>	<u>Capital Recovery Factor</u>
5%	0.122
10%	0.215
15%	0.322

Bases - Same as Case F Table 6-3 except for return rate.

TABLE 6-6

6-12

(1) Units - thousand dollars/year.

Total	<u>5000</u>
-------	-------------

(3) Assumed to be 7.4% of investment.

6.3 Shale Oil

A potentially important source of non-highway transportation fuels is shale oil. Incentives for developing the large domestic shale resource will increase as the cost of crude oil, especially imported crude oil, rises.

6.3.1 Shale Oil Process Description

The steps required for production of raw shale oil are: mining, crushing, and aboveground retorting. Another alternative currently being developed is referred to as in-situ retorting. In this process retorting occurs underground, in place, followed by product recovery. A further discussion of this process follows later in this section. It is possible to mine shale either using surface or underground methods. The major underground mining method involves the room-and-pillar technique, in which underground "rooms" are excavated, leaving pillars of unmined shale to support the structure. This operation has been demonstrated in prototype mines. Surface mining is a well developed technique for a variety of ores. It requires removal and disposal of existing overburden, followed by a quarry-like mining operation of the underlying shale. Thus far, this technique has not been applied to shale mining. For economic purposes the room-and-pillar technique has been selected in this study.

Oil shale has resiliency and abrasive properties which can lead to difficulties in the crushing operation. In addition, the retorting operation impacts on the shale particle size requirements. The recycled hot solids retort, such as the TOSCO retort, requires particles of 1/2 inch or less. The Gas Combustion Retort (GCR) of the Bureau of Mines has size requirements of 3 inches or smaller. However, the fines of 1/2 inch and less which are produced in crushing are unacceptable to the GCR and briquetting is required to use them. Alternatively, these fines could be used in an associated recycled hot solids retort.

Retorting is the process for recovering oil from the shale bearing rock. In the recycled hot solids retort direct contact heating of small sized shale particles with heated ceramic balls is used to pyrolyze the kerogen*, converting it to raw shale oil. Indications are that this retort is best suited for richer shales (30-35 gal/ton). In the Gas Combustion Retort (GCR) air is introduced in the middle of the retort where a combustion zone is created to generate the heat required for pyrolysis of the kerogen. The particle size required for this operation is larger than for the TOSCO retort, thereby reducing crushing requirements. However, flow problems occur with particles smaller than 1/2 inch and, as previously mentioned, briquetting or combination with a recycled hot solids retort will be required. Additionally, clinkering and flow problems result with shales of oil content in the 30-35 gal/ton range, thus this retort will find application with the somewhat leaner shales.

*Kerogen is the bituminous material occurring in oil shale that yields oil when heated.

Environmental concerns associated with aboveground retorting operations mainly involve the surface disposal of spent shale and, in view of these concerns, there is increasing interest in developing an underground, in-situ, retorting technique. Basic research indicates that fracturing of the impermeable rock is very difficult and it is crucial that an efficient method be developed to generate this permeability, so that heat for the retorting can be introduced and products withdrawn efficiently. It is conceivable that in-situ retorting can lead to environmental problems, such as subsidence and underground water contamination, which will require investigation. In general, it is too early to tell whether this technique will provide an effective means for recovering shale oil. The process economics section will be concerned with the recycled hot solids type of retort and 30 gal/ton shale richness.

6.3.1.1 Shale Oil Properties

When compared with conventional petroleum raw materials, raw shale oil has a high pour point, as well as high nitrogen and sulfur content. Sulfur and nitrogen must be removed either at the shale oil mining site or at the refinery where the shale oil is to be processed. The scheme investigated here is that the raw shale oil will be upgraded at the mining site to synthetic crude quality. A comparison of typical raw shale oil and syncrude properties is shown in Table 6-7. The upgrading consumes approximately 2000 SCF of hydrogen per barrel of raw oil feed. This syncrude is of high quality with about a quarter of its volume in the naphtha boiling range. As produced the syncrude fractions are useable as turbine fuels without further treating.

6.3.2 Production Economics for Raw Shale Oil and Syncrude

Raw shale oil can be produced for about 2.50 \$/MBTU (13 \$/Bbl). The total cost and components is shown in Table 6-8 for a production rate of 100,000 barrels per day of raw shale oil. The total cost includes a feedstock cost equivalent to a 1 \$ per barrel bonus bid payment, mining, retorting, and spent shale disposal.

Table 6-8

RAW** SHALE OIL COST

Investment	- \$/MBTU/Yr.	9.45	
Capital Recovery	- \$/MBTU		1.90
Operating Cost	- \$/MBTU		0.40
Feedstock Cost	- \$/MBTU		<u>0.20</u>
Total Cost	- \$/MBTU		2.50*

It is clear that capital recovery is the highest contributor (75%) to the total cost of raw shale oil. It is important to note that feedstock cost, i.e., resource value, will vary from project to project because of differences in bonus bid payments and will directly influence the total cost. A value of \$1 per barrel was assumed in this investigation.

The total cost for mining, disposal, retorting and upgrading the raw shale oil to syncrude is estimated to be 4.30 \$/MBTU (23 \$/Bbl). It is difficult to compare the raw shale production cost and syncrude production cost because no single reference addresses these issues separately. Therefore, caution should be used when trying to determine incremental costs for upgrading raw shale oil. An illustration of the total cost and its breakdown is shown in Table 6-9 for a 50,000 barrel per day operation (reference: 6-10).

*A single value does not imply that this is a precise value, but rather that only one literature reference was found for raw shale oil. This value probably would have a range of about 2.5-3 \$/MBTU.

**Also referred to in the Executive Summary as unrefined shale oil.

Table 6-7

TYPICAL PROPERTIES FOR RAW SHALE
OIL AND SYNTHETIC CRUDE

	Raw Shale Oil	Syncrude
Gravity, °API	28.0	46.0
Pour Point, °F	75	50
Sulfur, wt%	0.8	0.005
Nitrogen, wt%	1.7	0.035
RVP*, psi	-	8
Viscosity, SUS** at 100°F	120	40
Analysis of Fractions		
Butanes and Butenes, vol%	4.6	9.0
C5-350°F Naphtha		
Vol%	19.1	27.5
Gravity, °API	50.0	54.5
Sulfur, wt%	0.70	< 0.0001
Nitrogen, wt%	0.75	0.0001
k Factor***	11.7	12.0
Aromatics, vol%	-	18
Naphthenes, vol%	-	37
Paraffins, vol%	-	45
350-550°F Distillate		
Vol%	17.3	41.0
Gravity, °API	31.0	38.3
Sulfur, wt%	0.8	0.0008
Nitrogen, wt%	1.35	0.0075
Aromatics, vol%	-	34
Freezing point, °F	-	-35
550-850°F Distillate		
Vol%	33.0	22.5
Gravity, °API	21.0	33.1
Sulfur, wt%	0.8	< 0.01
Nitrogen, wt%	1.9	0.12
Pour Point, °F	-	+80
850 Plus Residue		
Vol%	26.0	None
Gravity, °API	12.0	
Sulfur, wt%	1.0	
Nitrogen, wt%	2.4	

* Reid vapor pressure.

** Saybolt universal seconds.

*** Empirical characterization factor relating specific gravity and molecular weight.

Reference: 6-11

Table 6-9COST OF SYNCRUDE (UPGRADED SHALE OIL)

Investment	-	\$/MBTU/Yr.	14.3-15.3
Capital Recovery	-	\$/MBTU	2.9-3.1
Operating Cost	-	\$/MBTU	1.1-1.2
Feedstock Cost	-	\$/MBTU	<u>0.2-0.1</u>
Total Cost	-	\$/MBTU	<u>4.2-4.4</u>

Again, it is capital recovery which is the major contributor, about 75%.

6.3.3 Syncrude Upgrading/Refining

Having produced syncrude this must be converted to fuels products in operations similar to those in conventional petroleum refining. This section will deal with economics of producing gasoline, and turbine and diesel fuels from shale synthetic crude.

A simplified flow sheet for a shale syncrude refinery is shown in Figure 6-3. Some key areas concerning shale syncrude are as follows:

- I. Shale syncrude, as indicated by the properties shown in Table 6-7 is quite different from conventional petroleum crude in that it contains no "bottoms", i.e., material boiling above 850-975°F. Consequently, the refining sequence does not employ any bottoms conversion.
- II. Syncrude contains very little sulfur and nitrogen, which reduces the need for hydrotreating during refining.

The simple upgrading sequence involves the following steps:

1. The syncrude is distilled into various fractions:
 - initial/375°F, which goes into gasoline production.
 - 375/650+°F, which is aimed primarily at distillate production.
- 2a. When maximum gasoline is required, all the 375+°F material is fed to the conversion process which is hydrocracking.
- 2b. For distillate and gasoline coproduction* the 375/650°F material is sent to the distillate pool and hydrocracking is replaced with catalytic cracking, a milder process, and the 650+°F material is cat cracked.

* Gasoline/Distillate ratio: 2.4/1 for prudent refining operations. See reference 6-11 for more information on this subject.

Figure 6-3

SIMPLIFIED SHALE SYNCRUDE REFINERY

The refining cost for upgrading shale syncrude to gasoline via the hydrocracking conversion route is about 0.7-0.8 \$/MBTU. When distillate is made by substituting cat cracking for hydrocracking and running more syncrude, the added operating costs are essentially zero since the savings for substituting a less costly conversion step offset the costs of running more feed. Thus, the cost of this distillate are the same as the cost of syncrude. It should be emphasized that it would be much more costly to make additional distillate beyond this increment. A summary of these costs is presented in Table 6-10.

Table 6-10

Shale Finished Product Costs

Fuel Product	Gasoline \$/MBTU	Distillate \$/MBTU
Syncrude Cost	4.2-4.4	4.2-4.4
Refining	0.7-0.8	0
Total Cost	4.9-5.2	4.2-4.4
Lower Heating Value, MBTU per barrel	4.95	5.40

Product qualities: the gasoline is 91 research octane number clear (RONC) and the distillate cetane number is 50.

As indicated in Table 6-10, gasoline can be co-produced for about 4.9-5.2 \$/MBTU (25-26\$/barrel) and distillate fuel for 4.2-4.4 \$/MBTU (23-24 \$/barrel).

6.4 Coal Cost

It is obvious that the cost of coal impacts on the cost of alternative fuels derived from coal. For the fuels derived from coal in this study it has been assumed that mine-mouth cost for a high sulfur/high BTU coal, such as Illinois No. 6, is 21 \$/Ton and for low sulfur/low BTU coal, such as Wyoming coal, 8 \$/Ton. Mine-mouth coal prices reflect mining costs plus resource value. Delivered coal prices, which vary from one geographic location to another, are the sum of mine-mouth plus transportation costs. Transportation costs are a function of distance and are covered in section 7.2. The total delivered cost of coal will include a transportation cost.

The literature* indicates coal prices which cover a broad range. A summary of variations in mine-mouth costs for different types of coal is shown in Table 6-11.

Table 6-11Mine Mouth Coal Costs - 1980 Dollars

Mine location Type of coal	Illinois High Sulfur	Wyoming Low Sulfur
Mine Mouth Cost, \$/Ton		
Minimum	14.00	5.30
Most likely	21.00	8.00
Maximum	30.00	12.00
Heating Value MBTU/Ton	22.80	16.50

* The main source of information in this study: Reference 6-8; other references: 6-18 and 6-19.

6.5 Coal Liquids

One of the major fossil energy resources in the United States is coal. Coal can be used directly as a fuel in non-highway transportation (rail and marine), to generate steam to power a steam engine or turbine. However, to be used in all forms of non-highway transportation, coal will need to be converted to a liquid form. To obtain reasonable yields of liquid fuels from coal, it will be necessary to break the large condensed ring compounds into smaller molecules and to add large amounts of hydrogen to increase the hydrogen-to-carbon ratio. Coal has a hydrogen-to-carbon weight ratio of around 0.07, compared to a hydrogen-to-carbon weight ratio of around 0.14-0.17 for petroleum products. The hydrogenation of coal also assists in removing the sulfur and nitrogen impurities.

6.5.1 General Process Classification

The various processes for producing liquid fuels from coal can be grouped into three general levels of processing severity. Table 6-12 shows the three general levels of processing severity (pyrolysis, liquefaction and indirect liquefaction) and several sub-levels of classification, along with some of the various processes that are being developed in each category.

Many articles have been written comparing the various processes. It is not the purpose of this study to make an in-depth analysis of the various coal liquefaction processes. The following sections will briefly describe each type of general processing method.

6.5.1.1 Pyrolysis

Pyrolysis is the least severe approach to producing liquids from coal. In direct pyrolysis, heat is used to distill the volatile portions of the coal without adding hydrogen. A general flow plan of coal pyrolysis is shown in Figure 6-4. Feed coal, crushed to the proper particle size, is heated to an elevated temperature (600-1500°F) to produce gas, oil and char. The oil is recovered and hydrogenated for upgrading to either a fuel oil or synthetic crude. The gases are recovered, purified, and used as plant fuel, hydrogen plant feedstock or sold as a by-product. The char is available for sale as a high BTU solid fuel or it can be gasified to produce a synthesis gas (primarily hydrogen and carbon monoxide). This synthesis gas can be used to produce SNG, methanol, ammonia, or liquids via the Fischer-Tropsch process.

In hydropyrolysis, the pulverized coal is heated in the presence of hydrogen to increase the yield of lighter products (gases and liquids).

6.5.1.2 Liquefaction

The second level of severity involves both heat and pressure and is usually referred to as coal liquefaction. The broad range of conditions at which liquefaction has been tested runs from 750°F and 300 psig up to 900°F and 10,000 psig. Hydrogen chemically reacts with some of the carbon to form hydrocarbons with molecular weights lower than the original coal molecules. A generalized coal liquefaction process scheme is shown in Figure 6-5.

TABLE 6-12

COAL LIQUEFACTION PROCESS CLASSIFICATION

<u>Classification</u>	<u>Example</u>
1. Pyrolysis	
• Direct	COED, Garrett, TOSCOAL Lurgi-Ruhrgas
• Hydropyrolysis	Clean Coke Hydrocarbonization
2. Liquefaction	
• Direct Hydrogenation	
- Non-Catalytic	Solvent-Refined Coal (SRC-I) Clean Coke
- Pseudocatalytic	SRC II, Oil/Gas
- Catalytic	Synthoil, H-Coal, Catalytic Coal Gasification (Gulf)
• H ₂ Donor Solvent	CSF (CRESAP), Exxon EDS
3. Indirect Liquefaction	Fischer-Tropsch, Methanol

Source: Adapted from article, "Coal-Liquefaction--State-of-the-Art,"
J. B. O'Hara, Hydrocarbon Processing, November 1976.

Figure 6-4
SCHEMATIC FLOW PLAN OF COAL PYROLYSIS

Source: "Status of Coal Liquefaction Technology," W. R. Epperly and H. M. Siegel. Presented at Ninth Intersociety Energy Conversion Engineering Conference, August 29, 1974.

Figure 6-5
COAL LIQUEFACTION PROCESS SCHEME

Source: "Status of Coal Liquefaction," Ibid.

With direct hydrogenation, ground coal is slurried in a recycle coal-derived solvent, mixed with a hydrogen-containing gas and reacted at elevated temperatures and pressures. In the non-catalytic processes, no external catalyst is used. In the pseudocatalytic processes, a portion of the reaction product is recycled to the feed slurry to increase the ash content, which apparently acts as a catalyst. In the catalytic version, a catalyst is used to speed up the reaction. In the hydrogen donor-solvent process, the hydrogen is added as a hydrogenated recycle coal-derived liquid and directly as H_2 to the reaction.

Various methods have been tested for separating the solids from the liquids, including distillation, coking, hydroclones, filters and centrifuges. The liquids are upgraded in either fixed or ebullating beds to remove sulfur and nitrogen and to increase the product hydrogen content. The hydrogen used in the process is manufactured from coal or liquefaction by-products via gasification of coal or char or by reforming of product gas.

6.5.1.3 Indirect Liquefaction

The most severe approach to liquid fuels from coal is the combination of coal gasification to produce a synthesis gas followed by catalytic synthesis of hydrocarbons. Fischer-Tropsch is one example of indirect liquefaction technology. Production of methanol from coal is another example. This methanol can be used directly as a fuel or catalytically converted to gasoline via the Mobil Oil Corp. process.* A general process sequence is shown in Figure 6-6.

Figure 6-6

INDIRECT COAL LIQUEFACTION SCHEME

The steps include gasification of feed coal to produce a synthesis gas, purification of the syn gas and conversion to liquids.

In the Fischer-Tropsch synthesis, the hydrogen and carbon oxides are catalytically converted into liquid hydrocarbons. This process is in commercial use in South Africa by SASOL.

* Chemical and Engineering News, January 30, 1978.

With the large number of coal liquefaction processes being developed, it is beyond the scope of this study to include all of these processes in the economic comparison or to cover the physical properties of the products from the various processes. Therefore, the information will be presented for the three basic processing methods: pyrolysis, liquefaction and indirect liquefaction. Also, since the economics of pyrolysis are sensitive to coal type and the economics for both pyrolysis and indirect liquefaction are very sensitive to the values assigned to the byproducts produced, the costs of liquids from these process types can range widely among applications and projects. Therefore, in developing illustrative coal liquids costs the costs for direct liquefaction are used due to this process' relative insensitivity to byproduct values. Sections 6.5.3 and 6.5.4 show how these are derived. Thus, these costs represent a median cost of coal liquids within the range of costs which could be derived for the various liquefaction processes.

The following sections will cover the process yields from each of the general categories and the properties of the liquids produced.

6.5.2.1 Product Yields - General

Each of the three general types of coal processing (pyrolysis, liquefaction, and indirect liquefaction) produces a different type of product mix. For example, pyrolysis produces primarily a char while liquefaction maximizes liquid products, and the indirect liquefaction produces a large amount of SNG as a by-product. A comparison of typical yields from the three general types of processes is shown in Table 6-13. As can be noted, direct liquefaction produces the highest yields of liquid fuels, which are of interest in non-highway transportation. However, it may be possible to utilize the char as a fuel for marine or rail transportation. The SNG is also a potential fuel that could be used in gas turbines. In addition the pyrolysis char and methane could be used to generate synthesis gas to feed an indirect liquefaction plant, but this would be more costly. Also, the process energy requirements would be higher than if the products were used directly as fuels.

Comparisons between the three general types of processes are complicated by the variation in yields between the various processes within each group, operating conditions, type of coal used, etc. In the following sections, product yields and properties of the various liquid fractions are described for a typical process within a given group. The aim is to point out the general characteristics of the liquid products as they apply to non-highway transportation fuels. It is not the purpose of this study to make an in-depth comparison between the various processes.

6.5.2.2 Pyrolysis Products: Yields and Properties

Typical product yields for pyrolysis of Illinois No. 6 coal are shown in Table 6-14. Note the large char yield about 62 wt% of the total product yield. Typical pyrolysis oil properties appear in Table 6-15. These properties are for the oil directly from the pyrolysis unit before any upgrading. ASTM distillation indicates a very low naphtha content, about a quarter of the material is in the middle distillate boiling range (325/650°F). While 75% boils above 650°F. In addition, the oil is low in hydrogen and high in oxygen, nitrogen and sulfur. Table 6-16 shows typical product syncrude properties. The upgrading of the raw pyrolysis oil consumes approximately 4300 SCF of hydrogen per barrel of raw oil. As the table shows the hydrogen to carbon ratio has been substantially increased while the nitrogen, sulfur and oxygen levels have been reduced. Additional treating will be required to further reduce the sulfur and nitrogen level.

Properties of the naphtha component of this syncrude are shown in Table 6-17. This naphtha contains a high percentage of naphthenes which are an excellent catalytic reformer feedstock once the impurities, such as sulfur, are removed. The naphtha is low in aromatics content and, therefore, has a low research octane number (RON) of 70. It is

Table 6-13

A COMPARISON OF TYPICAL PRODUCT YIELDS FOR COAL PROCESSES*

<u>Process</u>	<u>Pyrolysis</u>	<u>Liquefaction</u>	<u>Indirect Liquefaction</u>
Coal Input, Tons/Day:	24,000	24,000	24,000
Product Output:			
LPG, B/D	-	8,000	2,800
Naphtha, B/D	1,300	22,000	16,000
Diesel Fuel, B/D	-	-	12,800
Fuel Oil, B/D	12,250	29,000	4,000
Pipeline Gas, MSCF/D	37	-	210
Sulfur, LT/D**	305	700	800
Ammonia, ST/D	114	124	-
Char, Tons/D	10,730	-	-

* Values have been normalized to 24,000 Tons/day basis for comparison; following tables present yields as found in specific reference.

** Commercial practice in the sulfur industry is to use long tons (LT) of 2400 lbs. The other tons above are short tons of 2000 lbs.

Table 6-14

TYPICAL PRODUCT YIELDS FROM A DIRECT PYROLYSIS PROCESS

Input:	Coal	40,665 Tons/Day (Dry)
Output:		
	Char	18,178 Tons/Day
	Naptha	2,200 Barrels/Day
	Fuel Oil	20,756 Barrels/Day
	Pipeline Gas	63 MSCF/D
	Sulfur	519 LT/Day*
	Ammonia	193 Tons/Day

* LT = long tons of 2400 lbs.; other tons equal 2000 lbs.

Reference: 6-5

Table 6-15

PYROLYSIS OIL* PROPERTIES

Gravity	-4 °API
<u>Composition</u>	<u>Weight %, MAF** Basis</u>
C	81.5
H	7.1
N	1.1
S	2.0
O	<u>8.3</u>
	100.0
 <u>ASTM Distillation</u>	 <u>°F</u>
IBP	320
2 vol %	400
5	450
10	500
20	620
30	730
40	820
50	910
60	1000

* Raw product before upgrading to syncrude.

** Moisture and ash free.

Reference: 6-1

Table 6-16

SYNCRUDE* PROPERTIES FROM PYROLYSIS TYPE PROCESS

Gravity	25°API
<u>Composition</u>	<u>Weight %, MAF ** Basis</u>
C	86.4
H	12.4
N	0.1
S	0.05
O	1.05

* Upgraded pyrolysis liquids, Hydrogen addition - 4300 SCF/Bbl.

** Moisture and ash free.

Reference: 6-1

Table 6-17

SYNCRUDE NAPHTHA* PROPERTIES FROM PYROLYSIS TYPE PROCESS

Hydrocarbon Type Analysis <u>Liquid Volume %</u>	<u>Naphtha</u>
Paraffins	7.0
Naphthenes	71.2
Aromatics	21.8
Olefins	<u>nil</u>
	100.0
Gravity, 60°F	44°API
Sulfur, PPM	93
Research Octane No. clear	70

* Naphtha derived from upgraded pyrolysis oil.

Reference: 6-2

expected that this clear* RON can be substantially increased to 99-100 by processing, such as catalytic reforming.

Characteristics of various syncrude fractions are shown in Table 6-18. The 390/650°F boiling component is high in aromatics content** and consequently would be unsuitable for current turbo-jet or diesel engines. Severe hydroprocessing is required to meet current jet and diesel fuel specifications. The 350°F+ fraction, or any portion of it, could be used as a low sulfur fuel oil without further hydrotreating. The 650°F+ material might be suitable for hydrocracking, but the high density (low API gravity) would indicate that it would be very refractory for catalytic cracking. It would be necessary to add a lot of hydrogen to make products approaching conventional specifications.

6.5.2.3 Liquefaction Products: Yields and Properties

Typical product yields for liquefaction of Illinois No. 6 coal are shown in Table 6-19. It should be noted that the liquid yield from this type of process is twice that from pyrolysis processes.

Table 6-20 shows the composition of liquefaction naphtha, both raw and hydrofined. As with pyrolysis naphtha, liquefaction naphtha is high in naphthenes which can readily be converted to aromatics by reforming.

The 350/650°F fraction properties are presented in Table 6-21. The high aromatic content*** of the syncrude would prohibit use in current turbine and diesel engines without additional treating. Severe hydroprocessing of this fraction will be required for application in these areas. This fraction can be utilized as a fuel oil without further treating.

The 400°F+ product properties are summarized in Table 6-22. This product can also be used as a low sulfur fuel oil without further treating. Hydrotreatment for nitrogen and oxygen removal will be needed prior to hydrocracking or catalytic cracking this material to make naphtha or distillate products. Considerable hydrogen uptake would be needed to approach the hydrogen/carbon ratios typical of conventional products.

* Lead-free

** The 390-525°F boiling range derived from Illinois No. 6 contains 60 liquid volume percent aromatics.

*** Upwards of 80 weight % of the 350/650°F fraction.

Table 6-18

SYNCRUDE COMPONENT CHARACTERISTICS FROM PYROLYSIS TYPE PROCESS

	<u>350+ Fraction</u>	<u>390-650°F Fraction</u>	<u>650+ Fraction</u>
°API, 60°F	18.4	22.5	11.2
Flash Point, °F	160	215	400
Pour Point, °F	+25	-70	+70
Ash, weight %	0.007	0.0	---
Sulfur, weight %	0.16	0.004	0.07
Water & Sediment, %	0.10	---	---
Viscosity, SUS 100°F	52.5	39.3	---
Carbon Residue*	0.4	---	1.13
ASTM Distillation, °F			
Initial Boiling Point	354	436	557
10% Distilled	409	459	705
90% Distilled	780	586	870
End Point	---	613	---

* Conradson Carbon Residue Test.

Reference: 6-2

Table 6-19

TYPICAL PRODUCT YIELDS FROM A LIQUEFACTION TYPE PROCESS

Input:	Coal	24,000 Tons/Day (Dry)
Outputs:		
C ₃ and C ₄ LPG		8,000 Barrels/Day
C ₅ /400°F Naphtha		22,000 Barrels/Day
LSFO		29,000 Barrels/Day
Sulfur		700 LT/Day*
Ammonia		124 Tons/Day

* LT = long tons of 2400 lbs.; other tons equal 2000 lbs.

Reference: 6-3

Table 6-20

NAPHTHA PROPERTIES FROM A TYPICAL LIQUEFACTION PROCESSRAW

Gravity	41°API
<u>Composition</u>	<u>Weight %</u>
C	84.1
H	12.2
O	2.5
N	0.2
S	<u>1.0</u>
	100.0

Hydrofined*

<u>Composition</u>	<u>Weight %</u>
C	87.4
H	12.6
O	0.01
N	0.0007
S	0.0025

* Hydrogen consumption ~900 SCF/Bbl.

Reference: 6-3

Table 6-21

PROPERTIES OF THE 350/650°F FRACTION FROM
A TYPICAL LIQUEFACTION PROCESS

Gravity	15°API
<u>Composition</u>	<u>Weight %</u>
C	89.66
H	8.97
S	0.03
O	1.22
N	<u>0.12</u>
	100.00
Flash Point, °F	146
Pour Point, °F	-70
Kinematic Viscosity @ 100°F, cs	2.1

Reference: 6-3

Table 6-22

FUEL OIL PRODUCT PROPERTIES
(400°F+) FROM A TYPICAL LIQUEFACTION PROCESS

Gravity	-1°API
<u>Composition</u>	<u>Weight %</u>
C	87.9
H	7.0
S	0.8
O	3.2
N	<u>1.1</u>
	100.0
Flash Point, °F	196
Pour Point, °F	40
Viscosity, SSF at 122°F	158

Reference: 6-3

6.5.2.4 Indirect Liquefaction: Yields and Properties

Indirect liquefaction processes produce substantial amounts of substitute natural gas (SNG). Typical product yields for indirect liquefaction are shown in Table 6-23. Note the large yields of SNG and the relatively small yields of liquids. These liquid products, however, are essentially in a useable form, i.e., naphtha, diesel fuel and fuel oil, without additional treatment.

The properties of the naphtha component are summarized in Table 6-24. The naphtha is mainly composed of straight chain saturated and monounsaturated hydrocarbons; thus, these naphthas may have a high potential as a feedstock for ethylene production. In addition, the naphtha contains nil sulfur and near nil aromatics. This low aromatics content results in a low octane number. Extensive processing involving catalytic reforming would be required to raise the octane number. Part of the heavy naphtha product could possibly find application as a turbine fuel.

The properties of the diesel fuel product appear in Table 6-25. This product contains nil sulfur, has a high cetane number and a high heating value. It is considered as a marketable diesel fuel or alternatively a low sulfur boiler fuel or a home heating oil. As with the naphtha, this product can also be used as a turbine fuel.

Indirect liquefaction fuel oil could be marketed as a high-pour fuel for use in the industrial or marine sectors for turbine or diesel drivers or as boiler fuel. The properties of this product are summarized in Table 6-26. The nil sulfur, metals and nitrogen content should provide an advantage. With only trace quantities of aromatics projected, the luminosity usually associated with other coal derived fuels should not exist.

Table 6-23

TYPICAL PRODUCT YIELDS FROM AN
INDIRECT LIQUEFACTION TYPE PROCESS

Input: Coal 30,000 Ton/Day (dry)

Outputs:

SNG	260 MSCF/Day
C ₄ 's	3,500 Barrels/Day
Naphtha	20,000 Barrels/Day
Diesel Fuel	16,000 Barrels/Day
Fuel Oil	5,000 Barrels/Day
Sulfur	1,000 LT/Day
Electricity	140 MW

* LT = long ton of 2400 lbs.; other tons equal 2000 lbs.

Reference: 6-4

Table 6-24

NAPHTHA PROPERTIES FROM AN
INDIRECT LIQUEFACTION TYPE PROCESS

	Light Naphtha	Heavy Naphtha
Gravity, °API	85.5	71.3
ASTM Distillation		
IBP	96	186
10%	115	208
30%	128	226
50%	137	236
70%	146	253
90%	159	266
EP	185	300
Freezing Point, °F	-136	-67
Oxygen content, weight %	0.2	0.5
Sulfur, weight %	nil	nil
Reid Vapor Pressure, psia	10	
RON clear*	75	
MON clear**	65	

* Research octane number for the total naphtha after treating.

** Motor octane number for the total naphtha after treating.

Reference: 6-4

Table 6-25

DIESEL FUEL PROPERTIES
FROM AN INDIRECT LIQUEFACTION TYPE PROCESS

Gravity	57°API
ASTM Distillation	
IBP	301
10%	327
30%	351
50%	372
70%	421
90%	539
EP	637
Flash Point, °F	-100
Pour Point, °F	+10
Oxygen, weight %	0.5
Sulfur, weight %	nil
Ash, weight %	0.01
Cetane No.	60+
IP smoke point, mm	25

Reference: 6-4

Table 6-26

FUEL OIL INSPECTIONS FROM AN INDIRECT LIQUEFACTION TYPE PROCESS

Gravity	41°API
ASTM Distillation	
IBP	572
5%	642
10%	665
30%	715
50%	759
70%	811
90%	873
95%	886
Viscosity, SSU at 100°F	155
Flash Point, °F	200
Pour Point, °F	150
Oxygen, weight %	0.5
Sulfur	nil

Reference: 6-4

6.5.3 Economics of Producing Coal Liquids

Numerous estimates of the capital investment and operating costs of the various liquefaction processes are available in the literature. Most of the processes are still being developed, so the data necessary for a detailed equipment design and economic analysis are not available.

One must be extremely cautious when comparing estimated costs of conceptual coal conversion processes and projects. Information used in many estimates is preliminary and frequently optimistic. Additionally, even for a particular process, results can differ depending on plant size, coal source and cost, product slate and location.

The following sections are designed to cover:

- 1) Total cost and its components
 - + Capital investment
 - + Operating cost and co-product credit
 - + Feedstock cost
- 2) Variation of total cost with plant size
- 3) Variation of total cost with coal type
- 4) Selection of the representative cost.

This total cost will be expressed in dollars per million BTU of liquid product and dollars per equivalent barrel (Eq B)* of liquid product. Co-product gas and char which contain substantial heating value are not included in the divisor. These co-products have been credited against the operating costs at their most likely values. These same units (\$/MBTU of liquid product) will apply to the operating cost and feedstock costs as well. The total cost in \$/MBTU of liquid product is equal to [(Feedstock Cost + Capital Recovery + Operating Cost, all in \$/Yr.) divided by (Liquid BTU production, in MBTU/Yr.)].

* 1 equivalent barrel = 5.8 MBTU Lower Heat Value.

Variations in coproduct value will have a major impact on the economics of producing liquids by pyrolysis and indirect conversion. These impacts will be discussed in later sections.

6.5.3.1 Total Costs of Coal Liquids from Direct Liquefaction

The range of costs for direct coal liquefaction are shown in Table 6-27. The costs are for syncrude only, and if these products are to be used as motor gasoline or aircraft jet fuel, upgrading costs must be added to these costs. Upgrading costs are discussed in Section 6.5.4.

TABLE 6-27

TOTAL COST OF COAL LIQUIDS FROM DIRECT LIQUEFACTION

Process	\$/MBTU *	Total Costs
		\$/Eq. B **
Direct Liquefaction	3.75 - 6.30	22 - 36

The factors that contribute to these manufacturing costs are:

- 1) Capital Investment
- 2) Operating Costs less credit for by-products
- 3) Feedstock Costs

* Dollars per Million BTU of Product, Lower Heating Value (LHV).

** Dollars per barrel, 5.8 Million BTU per Barrel (LHV).

6.5.3.2 Capital Investment for Direct Coal Liquefaction Processes

The variation of the capital investment for direct coal liquefaction is shown in Table 6-28. Investments have been charged against liquids alone.

Table 6-28

INVESTMENT LEVELS FOR DIRECT COAL LIQUEFACTION

Process	Capital Investment	
	\$/MBTU/Yr.*	\$/Bbl/Yr.**
Direct Liquefaction	9.00 - 18.00	52 - 104

6.5.3.3 Operating Cost/Co-product Credits

The breakdown for Total Cost is shown in Table 6-29. Obviously, these processes will be extremely sensitive to market values assigned to the co-products. For direct liquefaction the by-products are sulfur and ammonia and if these had zero value the total cost would increase by approximately 0.30\$/MBTU (5-8%). Direct liquefaction costs are not too sensitive to co-product values due to the high yield of liquid products.

* Dollars per Million BTU of product, Lower Heating Value, liquid products only.

** Dollars per Barrel, 5.8 Million BTU per Barrel, liquid products only.

Table 6-29*

TOTAL COST BREAKDOWN FOR DIRECT LIQUEFACTION COAL LIQUIDS

Process	Direct Liquefaction
Capital Recovery**	1.79 - 3.57
Operating Costs	0.79 - 1.30
Co-product Credits:	
Sulfur	- (0.19)
Ammonia	- (0.13)
Net Co-product Credits	0 - (0.32)
Feedstock Costs ***	<u>1.18 - 1.71</u>
Total Cost	<u>3.76 - 6.26</u>

* All figures are \$/MBTU of liquid products.

** 0.20 times the capital investment.

*** Coal is priced at 21 \$/Ton.

6.5.3.4 Feedstock Cost

The range of feedstock costs for direct coal liquefaction is shown in Table 6-29. Direct liquefaction has a feedstock cost of about 1.70\$/MBTU for a high sulfur coal.

6.5.3.5 Variation of Total Cost with Plant Size

The analysis up to this point has been for plants that produce the equivalent of 50,000 barrels per stream day of liquid product. This section will discuss the effect of plant size on manufacturing cost.

Doubling the size of these process plants will effectively reduce the unit cost of manufacture by about 7%. Table 6-30 compares the manufacturing cost for direct liquefaction with equivalent production of 100,000 barrels per stream day versus 50,000 barrels per stream day.

The major reason for this somewhat small reduction of production cost is that increasing production rate will entail multiples of equipment with limited economy of scale effects. These changes in plant size can be characterized by a proration factor of 0.9.

Table 6-30

COMPARISON OF TOTAL COST FOR 100 kB/D AND
50 kB/D PRODUCTION

Process	Total Cost, \$/MBTU	
	100 kB/D	50 kB/D
Direct Liquefaction	3.50- 5.80	3.75- 6.25

6.5.3.6 Variation of Total Cost with Coal Type

Various references (6-6, 6-7) have shown that for production of similar product slates using a lower sulfur/lower heat content coal (relative to Illinois No. 6) will result in an approximate 10% reduction in manufacturing cost directly traceable to feedstock cost reduction. A comparison of the reduction in cost of the liquid products from two types of coal is presented in Table 6-31.

Table 6-31

Feedstock Cost and Manufacturing Cost with Wyodak, Wyoming*
Coal Compared with Illinois No. 6 ** coal.

Process	Feedstock Cost, \$/MBTU		Total Cost, \$/MBTU	
	Wyodak	Illinois	Wyodak	Illinois
Direct Liquefaction	0.70-1.20	1.20-1.70	3.25-5.75	3.75-6.25

These feedstock cost savings are diluted by increased investment and operating costs due to the Wyodak's higher moisture content. Additionally, there are examples in the literature (6-8) which show that the transportation of Wyodak, Wyoming coal can reduce and even eliminate the feedstock cost advantage for this coal type. A summary of the properties for these coal types is presented in Table 6-32. Note the relatively higher moisture and oxygen, but lower carbon content of the Wyoming coal.

* Priced at 8\$/Ton

** Priced at 21\$/Ton

Table 6 - 32

COAL PROPERTIES

<u>Illinois No. 6</u>		<u>Wyodak, Wyoming</u>
<u>Analysis, wt% (Dry Basis)</u>		
C	70.15	65.59
H	5.07	4.79
O	10.24	18.24
N	1.19	0.93
S	4.14	0.70
Cl	0.11	0.03
Ash	<u>9.10</u>	<u>9.71</u>
	100.00	100.00
 <u>Moisture (as received), wt%:</u>		
	16.5	30.0

6.5.4 Coal Liquids Upgrading

Section 6.5.3 covered the economics of producing synthetic crudes from coal. These "crudes" must be converted to fuel products in operations analogous to petroleum refining. This section deals with the economics of producing gasolines, turbine fuels, etc., from direct liquefaction liquids. The literature indicates that most of the government sponsored research and development work on coal liquids has centered on liquefaction, and there has been little work on producing fuels such as gasoline, turbo fuels and diesel from the coal liquids. This section will be addressed to the economics of producing fuels from coal liquids.

Coal liquids boiling above 350-400°F may be suitable for boiler fuels providing that the sulfur levels do not exceed mandated levels. It is conceivable that 400°F+ liquids could be shipped direct to industrial and marine consumers bypassing refineries. For these outlets further upgrading costs are unnecessary. It may be necessary to segregate coal-based boiler fuels from petroleum-based boiler fuels to avoid formation of solid precipitates which can occur when fuel components are not completely miscible.

The coal liquids must be refined to produce other fuels such as gasoline, and turbo and diesel fuels. The principal characteristics of coal liquids are their low hydrogen content and the high levels of oxygen and nitrogen and sulfur.

For satisfactory engine performance it is assumed that spark ignition fuels must have a minimum hydrogen content of 12.5 wt%* and turbine and diesel fuels a minimum hydrogen content of 13.5 wt%** . To achieve these levels, severe treating will be needed. Such hydrotreatment would also convert the oxygen, nitrogen, and sulfur in the feed to water, ammonia, and hydrogen sulfide. Removal of these impurities is probably necessary for satisfactory engine performance.

As mentioned above, consistent technical and economic data on the refining of coal liquids are not available. A system was developed for roughing out comparative economics for upgrading syncrude to gasoline, diesel, and turbine fuels.

The cost of hydrogenating coal liquids is assumed to be proportional to hydrogen consumption, and would be the sum of the cost of hydrogen itself and the cost of running the hydrogenation units. It is assumed that hydrogenation costs would be about the same per unit of hydrogen consumption as petroleum vacuum gas oil hydrocracking units. To these costs were added typical refinery costs for receiving crude, shipping products and primary distillation. These costs are shown in Table 6-33.

* Corresponds to a mixture of hydrocarbons with 50% aromatics.

** "Synthetic Petroleum for Department of Defense Use," SRI, Menlo Park, Calif., November 1974, P.47.

Table 6-33UPGRADING COST COMPONENTS

<u>Hydrogenation Costs</u>		
- Equipment	0.28	\$/pound of Hydrogen
- Hydrogen	0.50	\$/pound
 Primary Distillation, and feed & product <u>handling</u>		
	0.20	\$/MBTU of Syncrude

As the table indicates approximately two thirds of the total hydrogenation cost is the hydrogen itself; the balance belonging to the equipment operation. The cost of distillation, feed and product handling is assumed the same as for a conventional petroleum atmospheric pipestill of 150,000 barrels per stream day.

The cost of producing syncrude, with the added cost of distillation, feed and product handling are presented in Table 6-34.

Table 6-34

Cost of Coal Liquids including Primary Distillation, Shipping
and Receiving

Process	Cost	
	\$/MBTU	\$/Bbl
<u>Direct Liquefaction</u>	3.95-6.50	23-38

6.5.4.1 Coal Liquids Upgrading Costs

The costs for upgrading the products of direct liquefaction are shown in Table 6-35. Due to the limited available information and the roughness of the estimates, it is recommended that the higher end of the range be used for comparison purposes.

6.5.4.2 Coal Liquids Overall Cost

Using the information now developed, it is possible to determine the cost of producing, distilling, upgrading and handling the products from direct liquefaction. This cost appears in Table 6-36.

6.5.5 Hydro Pyrolysis Liquids Costs

As was previously mentioned, the cost of pyrolysis liquids is very sensitive to the type of coal used and the value placed on the relatively large volumes of char and gas produced. Using the same economic basis and evaluation approach for pyrolysis as for direct liquefaction, and valuing the char on a heat content parity with coal and the SNG at about 6 \$/MBTU*, the costs shown in Table 6-37 can be derived. As the table shows, the cost of pyrolysis liquids, 8.85 \$/MBTU, is higher than that for direct liquefaction liquids. It should be noted that these costs are based on Illinois coal feed and that lower cost coals which provide higher yields of pyrolysis liquids would, naturally, provide lower cost pyrolysis liquids.

* See section 6.11 for more information on substitute natural gas.

Table 6-35

UPGRADING COSTS FOR DIRECT LIQUEFACTION

Product			
Gasoline*		Distillate**	
\$/MBTU	\$/Bbl	\$/MBTU	\$/Bbl
0.90 - 1.90	5.20 - 11.00	1.40 - 2.50	7.10 - 14.50

Table 6-36

PRODUCT COSTS*** FOR DIRECT LIQUEFACTION

Product			
Gasoline*		Distillate**	
\$/MBTU	\$/Bbl	\$/MBTU	\$/Bbl
4.85-8.40	28-49	5.35-9	31-52

* \$/MBTU and \$/Bbl of liquid product.

** \$/MBTU and \$/Bbl of liquid product boiling above 350-400°F.

*** Includes: cost of production, distillation, upgrading and handling.

Some investigators have reported that hydro pyrolysis such as the "Clean Coke" process might provide transportation liquids at costs comparable to upgraded direct liquefaction liquids. It is conceivable that pyrolysis could be a preferred process under certain conditions and where lower quality liquids could be used, e.g., when building new coal based power facilities, it may be economical to build larger coal receiving and preparation facilities, recover pyrolysis liquids, and burn char, rather than coal, directly in the new facility and burn the pyrolysis liquid in the older boiler.

Table 6-37

TOTAL COST BREAKDOWN FOR HYDRO PYROLYSIS LIQUIDS*

		Direct Hydro Pyrolysis, \$/MBTU (1980)
Capital Recovery		6.75**
Operating Costs		2.10
Co-product Credits:		
Char	(3.40)	
Sulfur	(0.23)	
Ammonia	(0.29)	
Substitute Natural Gas	<u>(2.50)</u>	
Net Co-product Credits		(6.40)
Feedstock Costs		6.40***
Total Cost		<u>8.85****</u>

The upgrading costs for pyrolysis liquids, on the same basis as for direct coal liquids, are shown in Table 6-39. The upgrading costs for pyrolysis liquids are somewhat lower than for direct liquefaction liquids.

* All figures are \$/MBTU of liquid products.

** Corresponds to investment level of about 34.00 \$/MBTU/Yr.

*** Coal at 21 \$/TON.

**** Single value not meant to imply precision in number -- rather that only one reference was available.

Table 6-38UPGRADING COSTS

	Product			
	Gasoline**		Distillate***	
	\$/MBTU	\$/Bbl	\$/MBTU	\$/Bbl
Pyrolysis	0.40-1.60	2.30-9.30	0.80-2.15	4.60-12.50

Representative total costs for fuel products including primary distillation, shipping and receiving are shown in Table 6-39.

Table 6-39REPRESENTATIVE COSTS OF FUEL PRODUCTS* FROM PYROLYSIS

	Product			
	Gasoline**		Distillate***	
	\$/MBTU	\$/Bbl	\$/MBTU	\$/Bbl
Pyrolysis	9.45-10.65	55-62	9.85-11.2	57-65

* Includes cost of production, distillation, upgrading and handling.

** \$/MBTU and \$/Bbl of liquid product.

*** \$/MBTU and \$/Bbl of liquid product boiling above 350-400°F.

These total costs are higher than those for direct liquefaction based on the information available. It is worth re-emphasizing that for a specific project pyrolysis may be the preferred alternative.

6.5.6. Indirect Liquefaction Product Cost

The economics of producing fuel products via the indirect liquefaction mode, e.g., Fischer-Tropsch, is extremely sensitive to the value assigned to substitute natural gas. Using the same economic basis and evaluation approach as for direct liquefaction, and valuing the SNG at about 6 \$/MBTU*, the cost shown in Table 6-40 can be developed.

Table 6-40

TOTAL COST BREAKDOWN FOR INDIRECT LIQUEFACTION PRODUCTS**

<u>Indirect Liquefaction, \$/MBTU (1980\$)</u>	
Capital Recovery	7.10***
Operating Costs	2.50
Co-product Credits:	
Sulfur	(0.20)
Electricity	(0.20)
Substitute Natural Gas	<u>(6.20)</u>
Net Co-product Credits	(6.60)
Feedstock Costs	2.85****
<u>Total Cost</u>	<u>5.85*****</u>

The total cost for indirect liquefaction products, 5.85 \$/MBTU, shown in Table 6-40 is a true total cost. The liquids as produced are saleable as distillate fuels, i.e., for turbine application and the facilities

* Refer to Section 6.11 for more information on substitute natural gas.

** All figures are \$/MBTU of liquid product.

*** Corresponds to an investment level of about 36 \$/MBTU/Yr.

**** Coal at 21 \$/TON.

***** A single value is not meant to imply precision but rather that only one reference was available with enough detail to allow the cost to be adjusted to a common basis. The cost is very sensitive to the co-product credits.

provided include product storage and handling. Thus, this is the total cost and no additional costs will be added. Indirect liquefaction does not produce a liquid suitable for spark ignition engines; therefore, the total liquid product is treated as a distillate* and as such shows a substantial advantage over the distillates produced via direct liquefaction or pyrolysis. The advantage over direct liquefaction is about 2.55 \$/MBTU and the advantage over pyrolysis, even higher. It is important to realize the tremendous impact of the SNG credit**. If, for example, the credit was reduced by about 1 \$/MBTU, the gap separating indirect and direct liquefaction is reduced to about 1.40 \$/MBTU. If the credit is reduced by 2 \$/MBTU the gap reduces to only 0.25 \$/MBTU. If the credit is halved, the distillates from direct liquefaction are now cheaper.

6.6 Coal-in-Oil Slurry

A coal-in-oil slurry, referred to as colliodal fuel, is a combination of residual fuel oils*** and coal in particulate form. Colloidal fuel received considerable attention during World War I and II as potential fuel substitutes in case the petroleum supply was interrupted. Colloidal fuel could be a means of using coal reserves to extend limited petroleum resources and at least could provide a means of reducing residual fuel requirements. Colloidal fuels would also be made using shale or coal liquids.

6.6.1 Process Description

Coal is received at the facility and pulverized to produce coal powder. This coal powder is blended with residual fuel oil to produce the colloidal fuel. The blending operation is assumed to be similar to a conventional refinery process unit of minimum complexity (reference 6-17). For this study, it has been assumed that coal will be 40 weight % of the mixture. This appears to be the maximum allowable coal content due to pumping considerations.

* The conventional naphtha fraction is expected to have a sufficient hydrogen content to allow such treatment.

** Government regulation or similar forces could affect the value of this credit substantially.

*** The economics are based on using a conventional petroleum residual oil. However, use of a shale or coal derived oil should be possible but the oil cost would be higher than the value used in this study.

6.6.2 Costs of Colloidal Fuel

Using the low cost western coal at 8\$/ton, colloidal fuel can be produced at a cost of 87 \$/ton (2.55 \$/MBTU) well under the cost of fuel oil - 3.30 \$/MBTU. The higher cost Illinois coal will add approximately 5 \$/ton to the above cost, however due to its higher heat content the cost per MBTU remains relatively unchanged.

Table 6-41

Cost of Colloidal Fuel

Operating plus Capital Recovery Cost \$/MBTU	Feedstock Cost \$/MBTU*	Total Cost	
		\$/MBTU	\$/ton**
0.35	2.20	2.55	87

6.7 Methanol

Today essentially all methanol manufactured in the U.S. is produced by catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. However, future shortages of natural gas and other hydrocarbons will encourage consideration of alternative routes to methanol. Routes which will be considered in this study include:

- 1) Coal
- 2) Biomass
- 3) Solid Waste Pyrolysis
- 4) Ocean Thermal Energy Conversion

* Coal at 8 \$/ton, fuel oil 119 \$/T (20 \$/Barrel).

** Based on 40 wt% coal in blend, 33.94 MBTU per ton.

6.7.1.1 Coal

The first step in converting coal to methanol involves the production of a synthesis gas. Gasifier operating conditions vary from 1 to 40 atm and 1000-3300°F. The synthesis gas is fed to a conversion unit where hydrogen reacts with carbon monoxide or carbon dioxide at 750-1500 psi and at 400-600°F over a catalyst to produce the methanol. The reactions involved are:

Figure 6 - 7 presents a simple schematic for the production of methanol from coal.

FIGURE 6 - 7
Production of Methanol from Coal

Since conversion per pass is low, unreacted carbon oxides and hydrogen are recycled to the conversion unit. The ICI (100 atm) methanol technology is used in the conversion step. The production of 2000 tons per day of methanol requires 3500 tons per day of Illinois coal. Currently the largest plant produces 2000 tons per day via light hydrocarbon reforming. This was chosen as the economic basis.

6.7.1.2 Economics of Methanol Manufacture from Coal

The cost of methanol from coal is presented in Table 6-42. Investment levels are of the same order of magnitude as pyrolysis processes for coal liquids and the feedstock cost is also of the same order. However, the operating cost is higher, and the total cost is about 6.65-11.15/MBTU (113-190\$/ton).

TABLE 6-42
Cost of Methanol from Coal

Investment	- \$/MBTU/Yr.	15-34	
Capital Recovery	- \$/MBTU		3.00 - 6.80
Operating Cost	- \$/MBTU		2.00 - 2.25
Feedstock Cost	- \$/MBTU*		1.65 - 2.10
Total Cost	- \$/MBTU (\$/Ton)		6.65 - 11.15 (113-190)

* Coal is priced at 21\$/ton and plant size is 2000 tons/day.

A high operating cost is attributable to the inherent low yields per pass and resultant large recycle rates. The use of a co-product system may lower the cost.

6.7.1.2.1 Effect of Coal Type on Methanol Cost

For a 2000 TPD plant fed on low sulfur/low BTU western coal priced at 8\$/T the total cost is reduced by 0.45\$/MBTU. Table 6-43 compares the total cost and its components for the two coal types. The cost for either type of coal is essentially equivalent.

TABLE 6-43
Methanol Costs from Different Coals

Coal		Illinois	Wyoming
Investment	- \$/MBTU/Yr	34	36
Capital Recovery	- \$/MBTU	6.80	7.20
Operating Cost	- \$/MBTU	2.25	2.60
Feedstock Cost	- \$/MBTU	2.10	0.90
Total Cost	- \$/MBTU	11.15	10.70
	\$/Ton	190	184

As the table indicates, the feedstock costs are substantially lower for the Wyoming coal. However, these savings are diluted due to increased capital and operating costs because of the higher moisture content of the western coal. If the mines for this type of coal are remote from the synthesis plant any additional transportation costs will most likely eliminate the advantage for western coals.

6.7.2.1 Methanol from Biomass

Many investigations have recently been made into the feasibility of using biomass to supply energy. In general, the term biomass has been used to describe municipal solid wastes, agricultural wastes, and crops grown specifically as energy feedstocks. This section will consider a crop, sugarcane, grown specifically as an energy feedstock and the process sequence to methanol.

6.7.2.2 Process Route

The production of methanol from sugarcane involves: the generation of a synthesis gas from sugarcane fiber (bagasse) via the Purox Process or a similar gasification process, and the conversion of this synthesis gas to methanol. The bagasse is obtainable as a byproduct in the production of sugar from sugarcane or in the recovery of fermentable juice in an ethanol operation (see section 6.10). Reference 6-9 has established the price of bagasse at one dollar per MBTU of bagasse* (1976\$). This cost has been escalated and used in this study.

* Approximately 3600 BTU/lb

A simple depiction of the conversion of sugarcane fiber to methanol is presented in Figure 6-8..

Figure 6-8
Methanol Production from Sugarcane

The prepared fiber is sent to a Syngas unit where oxygen from an air separation plant is added. This syngas is then sent to a shift reactor where the required H_2 to CO ratio is generated. Once this is accomplished the gas is sent to the conversion reactor where steps as previously described for syngas derived from coal are carried out. Approximately 10,000 tons/day of sugarcane is required to make 1700 tons/day of fiber (dry) which in turn makes 430 tons/day of methanol.

6.7.2.3 Methanol from Biomass: Process Economics

It is estimated that methanol from biomass will cost approximately 14.80 \$/MBTU or approximately 253 \$/ton. This is about 60 \$/ton more than methanol from coal. The total cost and its components is shown in Table 6-44.

TABLE 6-44
Cost of Methanol from Sugarcane Fiber

Component	Investment \$/MBTU/Yr.	Capital Recovery \$/MBTU	Operating Cost \$/MBTU	Feedstock Cost \$/MBTU	Total Cost \$/MBTU
Syngas Generation	10.10	2.00	1.20	2.55	5.75
Methanol Synthesis	7.00	1.40	0.65	7.00	9.05
TOTAL	17.10	3.40	1.85	9.55	14.80

The synthesis gas generation contributes 60% of the total investment required, therefore, it also contributes the most to capital recovery costs. From an operating cost standpoint syngas generation is almost twice as expensive as the methanol synthesis and the total operating cost contributes 12.5% of the total cost. The table clearly indicates that feedstock cost is the major contributor to the total cost, 65%, and that the feed cost for the synthesis step, i.e., the syngas, is the largest single item in the total cost, almost 50%. The fiber itself comprises only 17% of the total cost and this fiber, as previously mentioned, has been priced at 1\$/MBTU as set out in reference 6-9.

6.7.3 Methanol from Other Sources

There are two other sources for producing methanol which have been considered:

- 1) Solid Waste Pyrolysis
- 2) Ocean Thermal Energy Conversion (OTEC)

6.7.3.1 Solid Waste Pyrolysis

Recently interest has been shown in investigating the utilization of municipal trash as an energy source. These waste materials can be pyrolyzed to gaseous products: methane, hydrogen, carbon monoxide, carbon dioxide, and water. This gaseous product can then be converted to methanol. The basic requirements for a synthesis gas are produced in the pyrolysis of waste and this is converted as described in the preceding sections. Approximately 3400 tons per day of municipal wastes are required to produce 400 tons per day of methanol. The cost of this waste to the producer has been assumed as 20 \$/ton.

6.7.3.2 Ocean Thermal Energy Conversion (OTEC)

This process takes hydrogen, made available by water electrolysis onboard an OTEC plant, and combines it with purchased carbon dioxide which is transported from an onshore facility to form methanol via the following reaction:

Approximately 1900 ton/day of carbon dioxide are required to produce 1245 ton/day of methanol.

The production costs of these alternate sources are discussed in the following section.

6.7.3.3 Cost of Methanol Production from Other Sources

The costs of producing methanol from solid waste and OTEC are summarized in Table 6-45. As the table indicates, both solid waste pyrolysis and OTEC are expensive processes. Relative to coal they are some 9 to 19 \$/MBTU (150-320 \$/ton) more expensive. The total cost for solid waste pyrolysis is 355 \$/ton and for OTEC about 509 \$/ton.

TABLE 6-45

Cost of Methanol* Via Solid Waste Pyrolysis and OTEC

Process		Solid Waste Pyrolysis	OTEC
Investment	- \$/MBTU/Yr.	55	39
Capital Recovery	- \$/MBTU	11.00	7.90
Operating Cost	- \$/MBTU	1.45	16.55
Feedstock Cost	- \$/MBTU	8.30	5.25**
Total Cost	- \$/MBTU	20.75	29.70

* All figures are based on lower heating value of methanol

** CO₂ at 63 \$/ton

6.7.4 Summary of Methanol Cost From Different Sources

Methanol costs vary over a wide range. A summary of methanol costs on a lower heating value basis for a 2000 ton per day production rate is presented in Table 6-46.

The table indicates that methanol can be manufactured from coal at a cost of about 113-190 \$/Ton, from sugarcane about 250 \$/Ton, from municipal waste at 355\$/Ton and by ocean thermal energy conversion at 509\$/T. Capital investments vary from 15\$/MBTU/Yr. - 55 \$/MBTU/Yr. (290 \$/Ton/Yr. - 943\$/Ton/Yr.) with biomass being the least capital intensive followed by coal, OTEC and solid waste. Solid waste is the least costly to operate and coal has the lowest feedstock cost. Essentially all the processes involve the production of a synthesis gas and the conversion of this gas using conventional technology. It is the route to this synthesis gas which varies from process to process.

TABLE 6-46

COMPARISON OF METHANOL COSTS FROM VARIOUS PROCESS

Conversion Route	Coal	Sugarcane	Solid Waste Pyrolysis	OTEC
Investment - \$/MBTU/Yr.	15-34	17	55	39
Capital Recovery - \$/MBTU	3.00- 6.80	3.40	11.00	7.90
Operating Cost - \$/MBTU	2.00- 2.25	1.85	1.45	16.55
Feedstock Cost - \$/MBTU	1.65- 2.10	9.55	8.30	5.25
Total Cost - \$/MBTU	6.65-11.15	14.80	20.75	29.70
	\$/Ton	113-190	253	355
			355	509

Alternatively, methanol costs can be compared on an index basis. Using the figures in Table 6-46 the indices shown in Table 6-47 can be calculated. This representation better illustrates the relative differences in total costs (note that each column is a separate comparison and that only the specific numbers in a particular column can be compared, columns cannot).

TABLE 6-47

RELATIVE VALUES OF METHANOL COST FROM VARIOUS PROCESSES

	Investment	Capital Recovery	Operating Costs	Feedstock Cost	Total Costs
Coal (upper range)	200	200	155	100	100
Sugarcane	100	100	128	455	133
Solid Waste Pyrolysis	320	320	100	395	187
OTEC	230	230	1140	250	267

6.8. Hydrogen

Nearly all industrial hydrogen currently produced in the U. S. is manufactured by the catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. The increasing cost and decreasing supplies of natural gas and light hydrocarbons provide a definite incentive for developing new processes for hydrogen manufacture. Coal gasification or electrolysis, are frontrunners in this regard.

6.8.11 Coal Gasification

Manufacturing hydrogen from coal involves several steps. First, finely ground coal is gasified with steam and oxygen at a temperature of about 2700°F to form hydrogen and carbon oxides as shown in Figure 6-9. Reaction temperature is controlled by adjusting the oxygen/steam ratio. Ash is withdrawn from the reactor as slag. Hydrogen yield is increased by the "shift" reaction in which carbon monoxide reacts with steam to make hydrogen and carbon dioxide. In the next step, carbon dioxide and hydrogen sulfide are removed with calcium oxide or other bases. Residual carbon oxides are removed by methanation. The Koppers-Totzek process, which has been widely used in Europe, employs these steps.

Other processes, such as Lurgi, employ a different type of gasifier which produces pyrolysis products such as tars, phenols, and methane as well as hydrogen and carbon oxides. The alternative technology requires less energy and may be preferable for making methane. However, the Koppers-Totzek gasification is probably better for making hydrogen. It avoids the problems of removing the methane, oils, etc., from the hydrogen.

The Koppers-Totzek gasifier operates at about atmospheric pressure. The gases are compressed to about 300 psig for shift and purification. There is substantial incentive for modifying the gasifier for higher pressure operation.

6.8.1 Process Economics For Coal Gasification

Hydrogen can be produced via coal gasification for 7.9-9.6 \$/MBTU. Table 6-48 shows the cost breakdown for this process. As the table indicates this route to hydrogen is capital intensive with capital recovery comprising 50% of the total cost.

Figure 6 - 9

CONVERSION OF COAL TO HYDROGEN

TABLE 6-48

COST BREAKDOWN FOR HYDROGEN VIA COAL GASIFICATION*

<u>Hydrogen from Coal</u>		
Investment	- \$/MBTU/Yr.	23-29.5
Capital Recovery	- \$/MBTU	4.6-5.9
Operating Cost	- \$/MBTU	1.6-1.9
Feedstock Cost	- \$/MBTU	1.7-1.8
Total Cost	- \$/MBTU	7.9-9.6

6.8.1.2 Effect of Coal Cost on Hydrogen Cost

The use of low sulfur, lower priced (8\$/Ton) western coals to produce hydrogen by gasification apparently reduces the cost by 0.50-0.60\$/MBTU. These cost reductions are mainly in raw material cost savings, however increased costs for coal handling and drying of the higher moisture western coal dilute these savings considerably.

The 8\$/Ton cost referred to above is at the mine mouth. If the mine were remote from the hydrogen plant the addition of transportation charges required to move the coal would offset the raw material cost savings. Thus, it might be more economical to use local coal for making hydrogen in the mid-west or east.

6.8.2 Hydrogen via Electrolysis

A simplified scheme for generating hydrogen via water electrolysis is presented in figure 6-10. The heart of the process is the medium with ion exchange properties that, with the addition of liquid water allows hydrogen ions to flow. Hydrogen ions are converted to hydrogen gas at the cathode. Current technology uses an aqueous potassium hydroxide (KOH) solution. An alternative which shows considerable promise, but which requires substantial development is the solid polymer electrolyte (SPE) which is currently being developed by General Electric. The following section presents a comparison of hydrogen costs via these alternatives.

6.8.2.1 Hydrogen Costs via Electrolysis

A comparison of costs for hydrogen via SPE and KOH electrolysis is presented in Table 6-49. Hydrogen can be produced for 19.65\$/MBTU by KOH technology and for about 13\$/MBTU via SPE technology. As the table indicates it is the considerable improvements in investment and operating costs which

* Basis: Coal at 21\$/Ton, Plant Size: 880 MSCF/D. This plant size is equivalent in BTU output, lower heating value, to a 250 MSCF/D natural gas plant. Basic investment is based on a 100 MSCF/D H₂ plant and a scaling factor of 1.

Figure 6 - 10

SIMPLIFIED FLOW SCHEME FOR HYDROGEN VIA ELECTROLYSIS

provide the incentive for developing the advanced SPE process. It is projected that SPE will lower investment by a factor of 4 and reduce operation cost by about 1.50\$/MBTU relative to the aqueous KOH technology.

The single factor which has the largest impact on the cost of hydrogen via this route is the cost of electricity. The estimates of production costs are based on an electricity cost 0.03\$/kwh. If this cost increased to 0.035\$/kwh the cost of hydrogen via KOH would increase to about 22\$/MBTU and for SPE to about 15\$/MBTU. Thus, a 17% increase in electricity cost causes a 12% increase in the cost of hydrogen using current technology, while the advanced SPE process increases by 15%.

Table 6-49

Hydrogen Costs From Electrolysis Processes*

		<u>Hydrogen via Electrolysis</u>	
<u>Electrolysis Process</u>		<u>SPE</u>	<u>KOH</u>
Investment	- \$/MBTU/Yr	9.00	35.00
Capital Recovery	- \$/MBTU	1.80	7.00
Operating Cost	- \$/MBTU**	11.20	12.65
Feedstock Cost	- \$/MBTU	<u>0.01</u>	<u>0.01</u>
Total Cost	- \$/MBTU	13.00	19.65

* Plant size: 880 MSCF/D; approximately equivalent to 250 MSCF/D Natural Gas Plant.

** Electricity: 3¢/kwh

6.8.3 Comparison of Alternative Hydrogen Processes

Coal gasification shows a considerable advantage over both electrolysis routes. Relative to current potassium hydroxide (KOH) technology the advantage is about 10\$/MBTU. While comparison with the solid polymer electrolyte (SPE) technology, which is currently under development, shows a smaller advantage of 3.50\$/MBTU. A comparison of the total cost and component contributions is presented in Table 6-50 for the three technologies.

In addition, typical process inputs and outputs are shown in Table 6-51. Coal gasification requires 2400 Tons/day to produce 100 MSCF/Day of hydrogen. The potassium hydroxide technology requires 520,000 kwh and 1100 thousand gallons of water per day to produce 100 MSCF/Day while SPE electrolysis requires 510,000 kwh and 575 thousand gallons of water per day for the same quantity of hydrogen.

Table 6-50Comparison of Production Costs for Different Hydrogen Technologies

		Coal	Electrolysis	
		Gasification	SPE	KOH
Investment	- \$/MBTU/Yr.	23-29.5	9	35
Capital Recovery	- \$/MBTU	4.60-5.9	1.80	7.00
Operating Cost	- \$/MBTU	1.60-1.9	11.19	12.64
Feedstock Cost	- \$/MBTU	1.70-1.8	0.01	0.01
Total Cost	- \$/MBTU	7.90-9.6	13.00	19.65

Table 6-51Typical Process Inputs and Outputs for Hydrogen Production

Process	Coal Gasification	SPE Electrolysis	KOH Electrolysis
Inputs:			
Coal, Tons/Day	2400	-	-
Electricity, KW	1450	510,000	520,000
Process Water, kgal/Day	7600	575	1,100
Outputs:			
Hydrogen, MSCF/D	100	100	100
Sulfur, Tons/Day	80	-	-

6.9 Ammonia

Currently ammonia provides the largest single requirement for industrial hydrogen. In the U.S. essentially all ammonia currently produced is made by catalytic steam reforming of natural gas or some other light hydrocarbon feed stock. Future shortages of these feed stocks and increases in their prices will provide the incentive for considering alternative feeds for ammonia manufacture. The alternative routes considered here are:

- 1) Coal
- 2) Biomass

6.9.1 Ammonia From Coal

As in hydrogen or methanol manufacture, the first step in ammonia manufacture is the production of synthesis gas. The gasifier products are cooled and then shifted to convert CO to additional hydrogen. The CO₂ is then removed and high purity nitrogen from air separation is added.

The ammonia synthesis gas is compressed to 2000-4500 psig and sent to the synthesis reactor where ammonia is formed at about 900°F over a promoted iron catalyst. Figure 6-11 illustrates a possible flow diagram for the conversion of coal to ammonia. The synthesis reaction is:

The production of 1500 ton/day of ammonia requires 2600 ton/day of coal.

6.9.1.2 Ammonia from Coal: Process Economics

Ammonia can be produced from coal at a cost of 208 \$/T (13 \$/MBTU). As with other coal conversion processes it is the required capital investment which contributes heavily to the total cost. In the case of ammonia capital recovery is 50% of the total.

Figure 6 - 11

CONVERSION OF COAL TO AMMONIA

Table 6-52 summarizes the component costs of this process. Operating costs contribute 36% of the total; and the remainder is the cost of the coal (feedstock).

Table 6-52

COST OF AMMONIA FROM COAL
(2000 Ton per day plant; Coal at 21 \$ per Ton)

Investment	-	\$/MBTU/Yr.	39
Capital Recovery	-	\$/MBTU	- 7.90
Operating Cost	-	\$/MBTU	2.2- 2.70
Feedstock Cost	-	\$/MBTU	2.2- 2.30
Total Cost	-	\$/MBTU	12.3-12.90
		\$/Ton	198-208

6.9.2.1 Ammonia From Sugarcane

The generation of synthesis gas from sugarcane has been discussed previously, in section 6.7.2.1, in the manufacture of methanol. This same synthesis gas can be converted to ammonia. The production steps required to produce ammonia from the Purox syngas are the same as those already discussed for the conversion of syngas derived from coal. Production of 568 ton/day of ammonia consumes 1700 ton/day of dry fiber, which consumes 10,000 ton/day of sugarcane.

6.9.2.2 Ammonia from Biomass: Process Economics

Ammonia can be produced from biomass by the Purox syngas process at a cost of approximately 283\$/TON (17.55\$/MBTU). This process alternative is less capital intensive with capital recovery contributing 27% of the total cost. The feedstock cost is about 50% of the total and this is the major difference between the biomass versus coal routes. The total cost breakdown appears in Table 6-53.

Table 6-53

COST OF AMMONIA FROM BIOMASS
(2000 Ton per day plant)

Investment	-	\$/MBTU/Yr.	23	
Capital Recovery	-	\$/MBTU		4.65
Operating Cost	-	\$/MBTU		4.25
Feedstock Cost	-	\$/MBTU		8.65
Total Cost	-	\$/MBTU		17.55
		\$/Ton	283	

A further breakdown which illustrates the contributions of Syngas generation and ammonia synthesis to the total is shown in Table 6-54.

Table 6-54

COST BREAKDOWN FOR AMMONIA FROM BIOMASS

Component	Investment \$/MBTU/Yr.	Capital Recovery \$/MBTU	Operating Cost \$/MBTU	Feedstock Cost \$/MBTU	Total \$/MBTU
Syngas Generation	9.65	1.90	1.70	2.30	5.90
Ammonia Synthesis	13.70	2.75	2.55	6.35	11.65
Total	23.35	4.65	4.25	8.65	17.55

The synthesis step in the production of ammonia contributes 60% of the total investment required, therefore it also contributes the most to capital recovery. Both the syngas generation and ammonia synthesis steps are expensive to operate. Again, synthesis contributes a higher percentage. Clearly the most expensive portion of the total cost is the feedstock cost; 50% of the total cost. The feed to the synthesis step is the syngas generated the step previously and this contributes about 75% of the total feedstock cost and is the largest single item in the total cost (more than 35%). The feedstock cost for the syngas generation step is bagasse, reference 6-9, the source of this information, has set the price of bagasse at one dollar per MBTU of bagasse* (1976\$). This cost was subsequently escalated and used in this study.

* Approximately 3600 BTU/lb.

6.9.3 Comparison of Ammonia from Coal and from Sugarcane

Ammonia from coal can be made cheaper than from sugarcane by about 75\$/Ton. The capital investment for coal, is higher at 39.45 \$/MBTU/Yr. versus 23.35 \$/MBTU/Yr. Both the feedstock and operating costs for the sugarcane alternative are considerably higher than for coal. The net difference between these factors provides the advantage for coal. Table 6-55 compares all of these factors and the total cost.

Table 6-55

COMPARISON OF AMMONIA COST FROM COAL AND BIOMASS

		Coal	Biomass
Investment	- \$/MBTU/Yr.	39	23
Capital Recovery	- \$/MBTU	7.90	4.65
Operating Cost	- \$/MBTU	2.2- 2.70	4.25
Feedstock Cost	- \$/MBTU	2.2- 2.30	8.65
Total Cost	- \$/MBTU	12.3-12.90	17.55
	- \$/Ton	198-208	283

6.10 Ethanol

Ethyl alcohol (ethanol) was extensively used in Europe as a motor fuel in the pre-World War II period. In the United States there has been minor use of ethanol as a fuel at any time. The low cost and availability of petroleum products have made extensive use of alcohols impractical. Currently ethylene, a petroleum product, is hydrated to produce industrial ethanol. As the cost of ethylene increases and availability decreases, incentives for developing alternative routes will grow.

The following alternative routes for producing ethanol will be discussed:

- 1) Fermentation of corn
- 2) Hydrolysis of wood followed by fermentation
- 3) Biomass Conversion.

6.10.1 Alternative Methods for Producing Ethanol

• Fermentation

Ethanol has been produced for centuries through the fermentation of fruits and grains. Essentially, fermentation is a decomposition process in which enzymes behave as catalysts. Feedstocks can be any material which contain or can be converted into hexose sugars. Such materials include: sugar beets, potatoes, rice, corn, molasses, and wheat. The general chemistry is illustrated below:

The product is a fluid containing ethanol and unconverted reactant. The ethanol is recovered by distillation. Wood can also be included as a feedstock because it contains cellulose which can be converted by hydrolysis into glucose.

• Hydrolysis of Wood (Cellulose)

Cellulose in wood can be converted into glucose by hydrolysis. This glucose is fermented and distilled into ethanol as previously described. There are two techniques for the conversion of cellulose:

- + acid hydrolysis
- + enzymatic hydrolysis

In acid hydrolysis weak acid solutions are added to wood chips and the mixture is "cooked" to generate the glucose. As its name infers, enzymatic hydrolysis involves enzyme attack for the conversion of cellulose to glucose. The concept of acid hydrolysis is not new; this technique is used commercially today to convert wood wastes to glucose. Enzymatic hydrolysis is a newer concept. A critical step in this process is the growth of a particular culture whose enzymes are required for conversion. In addition, the rate of hydrolysis is very sensitive to the form of the cellulose. The cellulose must be thoroughly milled for acceptable conversion by enzyme attack. Acid hydrolysis conversion requires only minutes while enzymatic hydrolysis requires hours.

The economics presented in the following section are based on the fermentation process.

◦ Biomass (Sugarcane) Conversion

Agricultural crops, such as the sugarcane, can be used as a source of ethanol. After shredding and mill extraction the sugarcane juice is recovered. This juice is directly fermentable and the fermentation step as previously described can be used for conversion of the juice to ethanol. Approximately 12,200 tons per day of juice containing 11.5 wt% fermentable sugars is required to produce 690 tons per day of 95 vol% ethanol.

6.10.2 The Cost of Producing Ethanol

The cost for 1500 Tons/day of ethanol by the fermentation of corn is 485\$/ton. While the literature provides some preliminary information on ethanol costs via acid hydrolysis and fermentation of wood and conversion of biomass, the investments quoted appear inconsistent with well established information on grain fermentation.

A cost buildup for ethanol via grain fermentation appears in Table 6-56.

Table 6-56

Cost of Ethanol from Corn*

Investment - \$/MBTU/yr	18
Capital Recovery - \$/MBTU	3.50
Operating Cost - \$/MBTU	4.20
Net Feedstock Cost - \$/MBTU	<u>13.50**</u>
Total Cost - \$/MBTU	21.20
- \$/Ton	485

* Source - Reference 6-20.

**Corn at \$3.75/Bushel.

The net feedstock cost, which contributes over 60% of the total cost of ethanol, is the cost of corn at \$3.75/bushel less a credit for the by-product dry grain, as high protein animal feed, selling at \$130/ton. Ethanol cost is quite sensitive to the cost of grain as illustrated in Table 6-57.

Table 6-57

Sensitivity of Ethanol Costs to Grain Price

Corn Cost - \$/Bushel	1.75	3.75	5.75
Net Feedstock Cost - \$/MBTU*	4.60	13.50	22.30
Total Cost - \$/MBTU	12.30	21.20	30.00

*Includes credits for by-product dry grain priced at 100, 130, and 160 \$/ton when corn costs 1.75, 3.75, and 5.75 \$/bushel.

Production of ethanol from wood or biomass may prove less costly than ethanol from grain. Higher investments and operating costs may be more than offset by lower feedstock costs.

6.11 Methane

In the past natural gas, i.e., methane has found application in the residential, commercial, industrial and power generating sectors due to its low cost, via government regulation, and clean burning properties. Recently, shortfalls in supply have been backing out natural gas from both the industrial and power generating sectors. A few years ago anticipated shortfalls triggered the production of a substitute natural gas (SNG) from hydrocarbon feedstocks, such as naphtha, especially in response to winter peak demands. The choice of hydrocarbons is due to the ease in producing SNG via steam reforming. Obviously, as the supply of natural gas and hydrocarbons continues to decline alternative sources of a natural gas type product, i.e., SNG, will have to be found. Probably the leading contender to augment gas supplies is coal. Biomass and sewage algae also represent potential sources of SNG. SNG can be used as a turbine fuel and may find application, in liquid form, as an aircraft fuel, and it could be used as a (gas) pipeline fuel.

6.11.1.1 Methane (SNG) from Coal

There are a large number of processes to convert coal to SNG under study; they involve the following steps:

- 1) Coal preparation
- 2) Gasification
- 3) Shift and Purification
- 4) Methanation
- 5) Compression

Some of the possible contenders are:

- a) Lurgi: 300 psig gasification
- b) Bituminous Coal Research, Inc. (Bi-Gas): 2 stage gasifier at 1000-1500 psig
- c) Institute of Gas Technology (Hygas): 2 stage gasifier at 1000-1500 psig
- d) Bureau of Mines (Synthane): fluid bed gasifier at 1000 psig
- e) Consolidation Coal Co. (CO₂ Acceptor)

In the gasification step, the products of importance are CO and H₂, CO₂ is also generated. The gasification products undergo shift reaction ($\text{CO} + \text{H}_2\text{O} \longrightarrow \text{H}_2 + \text{CO}_2$) to adjust the H₂ to CO ratio to about 3/1 to allow for subsequent methanation. The acid gases produced in this step (CO₂ and H₂S) are subsequently scrubbed out. In the methanator, CO and the small amount of remaining CO₂ are converted over a catalyst to CH₄ and H₂O with the release of large quantities of heat. The product SNG is dried and compressed.

6.11.1.2 SNG Production Economics

As previously mentioned there exists a large number of processes for SNG production all in various stages of study and commercialization. They all differ somewhat in particular gasifier design and by-products made, however, the production steps are the same for all and it is beyond the scope of this study to critically analyze each process. Thus, a range of costs for SNG from coal is presented in Table 6-58 for a plant size of 250 MSCF/D and 870 BTU/SCF (LHV), and coal at 21 \$/Ton (information derived from reference 6-12).

Table 6-58TOTAL COST OF SNG FROM COAL

Investment	- \$/MBTU/Yr.	17-22	
Capital Recovery	- \$/MBTU		3.40 - 4.40
Operating Cost	- \$/MBTU		.80 - 1.65
Feedstock Cost	- \$/MBTU		<u>1.90 - 2.70</u>
Total Cost	- \$/MBTU		<u>6.10 - 8.75</u>

6.11.2 SNG from Biomass and Sewage Algae

At this point in time the conversion processes for biomass and materials such as algae are conceptual and will require a great deal of development for significant impact on SNG production. It is perceived that the conversion of biomass will involve anerobic fermentation or an advanced pyrolysis or gasification system. The fermentation scheme will most likely yield methane and CO₂ directly, while the pyrolysis and gasification schemes will yield primarily CO and H₂ which will have to be converted to methane in a manner similar to that described in the section on Methane from Coal (6.11.1.1).

The production of algae for SNG production will involve these steps: growth of the algae in open ponds followed by harvesting, conversion of the algae by anerobic digestion to produce methane and CO₂ by fermentation. The problems which must be solved before implementation include:

- finding adequate water and CO₂ supplies (sewage waste is one possibility),
- maximizing algae growth,
- developing inexpensive harvesting methods,
- achieving reliable anerobic digestion.

The literature data (ref. 6-14) used to estimate the cost of methane (SNG) is based on assumed advances in these areas.

6.11.2.1 SNG Via Biomass and Algae Conversion

Indications are that conversion of biomass to SNG by a conceptual advanced process will yield SNG at about 8.00\$/MBTU and that algae conversion using an advanced process yields SNG at about 12.50 \$/MBTU. These total costs and cost components are compared with that of coal in Table 6-59 for a 250 MSCF/D plant size and product heating value of 870 BTU/SCF (LHV).

TABLE 6-59

COMPARISON OF TOTAL COSTS FOR SNG VIA
DIFFERENT ROUTES

Conversion Route	Coal	Biomass*	Algae*
Investment - \$/MBTU/Yr.	17-22	12.00	12.00
Capital Recovery - \$/MBTU	3.40-4.40	2.40	2.40
Operating Cost - \$/MBTU	0.80-1.65	1.00	4.35
Feedstock Cost - \$/MBTU	1.90-2.70**	4.60***	5.75***
Total Cost - \$/MBTU	6.10-8.75	8.00	12.50

* Prorations from smaller plants (60 MSCF/D) for comparison with coal based process; factor: 0.9.

** Coal at 21 \$/Ton.

*** Includes collection cost of 20 \$/Ton.

As Table 6-59 indicates, coal has an advantage over the biomass and algae routes. The feedstock cost difference between coal and biomass provides the basic advantage for coal, while it is a combination of operating and feedstock cost which provides the advantage for coal over algae processing. It is worth re-emphasizing that the costs for biomass and algae are based on the assumption of significant improvement over today's technology and will require demonstration. The coal based process is much further along in development and the estimate used is better substantiated.

6.12 Other Alternate Fuels

This section will deal with alternate fuels which have not been covered in previous sections. These fuels are:

<u>Fuel</u>	<u>Section Number</u>
Synthetic Oil from Organic Waste	6.12.1
Hydrazine	6.12.2
Acetylene	6.12.3
Methylamine	6.12.4
Low BTU gas	6.12.5
Electricity	6.12.6

6.12.1 Synthetic Oil from Organic Waste

A process is being developed for the conversion of solid organic wastes to a low sulfur synthetic oil which may have potential use in power plants or for conversion to petroleum type products. The production of this oil is achieved by reacting carbon monoxide, water and the organic waste at temperatures of 350-400°C and at pressures near 4000 psig in the presence of various catalysts and solvents. This oil is expected to cost about 8.60 \$/MBTU. A breakdown of this total cost is shown in Table 6-61. It should be noted that this is the cost of liquids as produced, without upgrading, and is far more expensive than the cost of either coal liquids or shale liquids (sections 6.5 and 6.3 respectively). A comparison of costs from these sources is also shown in Table 6-60.

Table 6-60COMPARISON OF SYNTHETICS LIQUIDS COSTS*

<u>Raw Material Source</u>	<u>Shale</u>	<u>Coal</u>	<u>Organic Waste**</u>
Investment - \$/MBTU/Yr.	14.3-15.3	9-18	10.00
Capital Recovery - \$/MBTU	2.9-3.1	1.8-3.6	1.95
Operating Cost - \$/MBTU	1.1-1.2	0.8-1.0	0.25
Feedstock Cost - \$/MBTU	0.2-0.1	1.2-1.7***	6.40****
Total Cost - \$/MBTU	4.2-4.4	3.8-6.3	8.60

* Production of 50,000 barrels per day without upgrading.

** Reference: 6-14.

*** Coal at 21 \$ per ton.

**** Includes waste collection cost of 20 \$/Ton.

6.12.2 Hydrazine

Hydrazine has a fairly high electrochemical reactivity and, therefore, may be attractive for use in fuel cells. Hydrazine can be produced by the Raschig process by the reactions shown below:

Process and investment information were not available, so the study approach has been to use the most recent costs available (as published in Chemical Marketing Reporter,* for the main raw materials: chlorine (135\$/ ton) and, ammonia (120 \$/ton) and using the reaction stoichiometry above determine the lower limit of the cost of hydrazine. With this approach no capital recovery costs or operating costs are taken into account so this represents the lower limit. This estimate showed that the hydrazine cost is about 37 \$/MBTU**. If the ammonia cost developed in this study is used, then the hydrazine cost is about 45 \$/MBTU**. The cost, as developed, is the bare minimum unless an alternative synthesis route is found. Chemical Marketing Reporter indicates current prices at 1.60 \$/lb or more than 200 \$/MBTU. Clearly, hydrazine is a very expensive material.

6.12.3 Acetylene

Acetylene can be produced by reacting calcium carbide and water or through the electric arc processing of coal at high temperatures. The literature (ref. 6-15, 6-16) indicates that acetylene can be produced for about 14 \$/MBTU. A summary of the total cost and its components is presented in Table 6-61.

Table 6-61

Total Cost of Acetylene

Process		Coal-arcng	Calcium Carbide
Investment	- \$/MBTU/Yr.	27	37
Capital Recovery	- \$/MBTU	5.40	7.40
Operating Cost	- \$/MBTU	6.95	4.75
Feedstock Cost	- \$/MBTU	1.70	1.85
Total Cost	- \$/MBTU	14.05	14.00

As a fuel acetylene has a high heating value (20,730 BTU/lb) but because it is unstable, pipelining or bulk transportation is highly improbable. The transportation cost for acetylene is covered in section 7.11.1.

* January 30, 1978; 1977 \$ are assumed.

** 1980 \$.

6.12.4 Methylamine

Methylamines are produced by the reaction of ammonia and methanol over dehydrating catalysts at temperatures ranging from 300°C to 500°C. The reaction product is a mixture of amines, unconverted reactant and water. Water is condensed out and the amines are separated by a series of distillations. The reaction chemistry is illustrated below:

Current selling prices* are about 0.33 \$/lb or about 25 \$/MBTU (1977\$). Using the costs of Ammonia (255 \$/T) and methanol (232 \$/T) developed in this study plus the reaction stoichiometry above, the lower limit of the cost for methylamine will be about 14 \$/MBTU (1980 \$).

6.12.5 Low BTU Gas

With curtailment of natural gas supplies or the exclusion of direct coal utilization, an alternate energy supply might be low BTU gas (LBG). LBG may find application in utility power generation, as an industrial fuel, or perhaps as a synthesis gas for chemical feedstock.

The source of LBG studied here is coal. Coal gasification technologies described for producing SNG (section 6.11) can be applied in the production of LBG with the substitution of air for oxygen in the gasifier. The product gases contain carbon oxides, hydrogen and nitrogen. The expected product heating value is about 180 BTU/SCF. However, after gasification and purification, the shift and methanation steps required for SNG are not used in making LBG, thus cost savings are realized. Using the data in reference 6-6, the cost for LBG is estimated to be 4.25 \$/MBTU. Additional charges for developing a gas distribution system may add considerably to this cost. A summary of the total cost is shown in Table 6-62 for a 1350 MSCF/D plant. This is equivalent to a 250 MSCF/D natural gas plant, since the low BTU gas has a lower heating value of about 180 BTU/SCF. The coal feedstock is assumed to cost 21\$/Ton.

Table 6-62

Cost of Low BTU Gas

		Coal
Investment	- \$/MBTU/Yr.	8.4-11
Capital Recovery	- \$/MBTU	1.7-2.20
Operating Cost	- \$/MBTU	0.7-0.80
Feedstock Cost	- \$/MBTU	1.25
Total Cost	- \$/MBTU	3.65-4.25

* As reported in the March 13, 1978 issue of Chemical Marketing Reporter.

6.12.6 Electricity

Electricity may find application in non-highway transportation in two modes: motor drives in pipeline operation and railroad electrification. In addition, the cost of electricity has a significant impact on the operating costs for most alternate fuel production schemes. Various routes for producing electricity have been reviewed (the information presented has been abstracted from reference 6-6). These are:

- Steam - electric cycle
 - + low sulfur coal
 - + high sulfur coal
- Nuclear
 - + light water reactor
- Solar

Electricity costs range from 2 ¢/KWH for low sulfur coal to almost 11 ¢/KWH for solar. A cost of 3 ¢/KWH is chosen for use in this study. This cost is equivalent to that for electricity from high sulfur coal. A summary of electricity cost and cost components is shown in Table 6-63.

TABLE 6-63Electricity Costs

Source	Steam-Electric		Nuclear		Solar
	Low Sulfur Coal	High Sulfur Coal	Light Water Reactor		
Investment	- ¢/kwh/Yr.	7.30	9.65	10.00	54
Capital Recovery	- ¢/kwh	1.45	1.95	2.00	10.80
Operating Cost	- ¢/kwh	0.10	0.20	0.10	0.10
Fuel Cost	- ¢/kwh	0.45	0.85	0.90	-
Total Cost	- ¢/kwh	2.0	3.0	3.0	10.90

6.13 The Cost of Fuels: Variation With Time

All of the cost estimates have been shown in terms of 1980 constant dollars; even so, it is necessary to consider whether the relative cost estimates (i.e., the ranking of estimated fuel costs) will remain valid over the period 1980 to 2000. This is considered to be a good baseline assumption, but it is not the only possibility. The technologies are at different stages of development and there can be variation in cost due to differences in estimating techniques, etc.

Experience with large commercial ventures involving complex technology indicates a pattern of cost-estimating and actual cost behavior that may be divided into two parts with "first commercialization" as the dividing line:

- (1) before first commercialization: significant cost escalation between "first concept" and pilot plant demonstration, and later between large pilot plant and first commercial plant. The range of the cost estimates is rather wide at first with the width decreasing as the time of first commercialization approaches.
- (2) after first commercialization: the cost of additional plants usually declines because experience permits many improvements to be made on an incremental basis; this experience is often termed the "learning curve".

This variation of capital cost with time for a new technology is illustrated in the following figure.

Figure 6-12 Technological Change Model For Capital Cost

SRI (6-21) has also quantified the effects of technological changes on capital costs (calling this "technological change on capital"). For all of the processes examined, the rate of decline in cost was similar, i.e., the cost at the "initial level" approached the "technological change limit" at about the same rate. If this finding is applicable to the alternate fuels in this study, then their relative cost rankings would not change significantly. Our baseline assumption is that this will be the case. However, a definitional and conceptual issue arises: what exactly is meant by "technological limit"? In a different form the question concerns the distinction between (a) technological improvements to identified technology, particularly those accomplished by engineering changes and "know how", and (b) advantages that may be achievable by radically different technology. For example, chemical and biochemical processes, such as are conceivable for biomass utilization, may be susceptible to radical rather than incremental improvement. An important research corollary follows:

- learning curve improvements are unlikely to change the economically competitive position of the high cost fuels; radically improved technology is needed for this purpose.

Constant dollars are an excellent device for comparing what has already occurred. In part, this is because the past has only one "scenario", i.e., what has actually occurred. This means that the different lead times, the different stages of development, and the different institutional problems associated with past technological developments not only are all known but the vector of their interactions is also known. This is not so when the future is addressed, except for a hypothetical baseline or reference case. Judgmental problems arise if technologies to be compared are not yet commercial and are at different, but not precisely known, positions (in time) on the upward part of the hypothesized cost curve. It is also possible for two competing technologies to "shift" in relative position after commercialization. This concept can best be illustrated by a hypothetical comparison between two new technologies "A" and "B". Figure 6-13 shows a series of frames, with each frame representing a different "real" time in the future. This is a dynamic simulation using a static format. The situation represented by each could be as follows:

Frame 1	Both A and B are new technologies that are under development.
Frame 2	A has moved into large pilot plant stage while B is still at the lab pilot plant stage because some problems, such as with metallurgy, have occurred.
Frame 3	A has checked out in the large pilot plant and moves to first commercial plant. Lab pilot plant difficulties with B are overcome and it moves to large scale pilot plant.
Frame 4	A starts down the learning curve when the second commercial plant is built. B checks out in the large scale pilot plant and first commercial plant is built.

Frame 5 First commercial plant for B works well and shows better reliability than A (or some other advantage not established until both full scale plants are operating). Hence the 2nd commercial plant for B is built and B starts down the learning curve. Another A plant is not built because B looks like the better technology. Therefore A does not move down the learning curve any more.

Frame 6 A is an obsolete technology that can't benefit from the learning curve, even though some improvements are possible, because no one is building A plants. B, however, continues down the learning curve.

One of the critical assumptions in the above scenario comes between Frame 2 and 3. If A is working as the large pilot plant, why would anyone continue to work on B, especially if A has moved to the commercial stage and B is still in the lab pilot plant stage? It has been assumed that some preceived institutional factor is able to keep B active past Frame 3.

Another, but quite different, difficulty arises if the technological comparison involves differences in capital intensity and/or project implementation time under conditions of general inflation. Constant dollars pertain to the GNP deflator, which is not necessarily an adequate indicator of how different sectors of the economy or different goods will experience cost inflation (i.e., "escalation"). In principle, labor costs, raw materials cost, and capital equipment costs will not experience the same degrees or patterns of cost inflation. Pragmatically, however, much of this difficulty disappears when comparisons are made within a given technological and raw materials subset, e.g., coal conversion. Many of the alternate fuels are derivable from coal, hence the economic rank-ordering of these fuels is much less susceptible to differential cost escalation than is potentially the case for such fuels versus those derived from a quite different resource such as biomass. However, there are factors that can cause a change in the technology to be used to produce the fuels; such as plant location restriction, difference in reactions with different types of coals, etc.

Still another kind of difficulty exists in relation to assumptions made about the pattern of future oil price changes in an economy that for many years is expected to be substantially dependent on oil. For example, the response to steady price changes may differ from what might be triggered by sudden sharp changes. Assuming technological readiness at the time of a sharp price increase, it is believed that quickly implemented technologies would be favored over those with long lead times, thereby permitting the learning curve of the quickly implemented technologies to begin sooner than those with long lead times. Put differently, Figure 6-12 is a static representation of learning curve behavior which does not necessarily capture the dynamics of technological choice.

Two further sets of observations may be made with respect to shale-derived and coal-derived fuels:

- (1) It is expected that shale derived fuels will be lower in cost than coal derived fuels. However, the development of shale fuels will not be governed only by economics. The environmental and water limitations of a large (multi-million barrel-per-day) shale industry are expected to be controlling.* The impact of such an industry will have to be studied and the economics of manufacture adjusted for any limiting factors which may be determined. In fact, the impact of an industry for any of these fuels supplying the non-highway transportation sector will require study and the impacts quantified. It is also important to realize that none of these fuels will be developed strictly for non-highway applications. Highway and industrial demands will play an important role as to which alternate fuels are developed. It is possible that the timing of the development will be controlled, or strongly influenced, by factors or purposes outside the NHT sector, and also that the timing may vary from purpose to purpose.
- (2) Operating experience plus ongoing research of potential process improvements can translate itself into lower investment requirements for a particular plant. Investments may even be reduced by 25-40% (on a constant \$ basis).** Coal liquids plants of the direct liquefaction process group have shown investment levels of approximately \$9-18 per MBTU per year. For discussion a level of \$15/MBTU/Yr is assumed; if this was reduced by 25 to 40%, the cost of coal liquids could be reduced by about 13 to 20%. These figures have been determined via a simplistic sensitivity calculation. In reality the actual cost and potential cost reductions will only be determined when commercial plants are built and operating experience is obtained.

* See reference 6-22 for more information on this subject.

** Reference 6-23.

Figure 6-13

SIMULATION OF WAY TWO NEW TECHNOLOGIES
MAY CHANGE RELATIVE POSITION WITH TIME

Frame 1 - Time = t_1

Frame 2 - Time = t_2

Frame 3 - Time = t_3

Frame 4 - Time = t_4

Frame 5 - Time = t_5

Frame 6 - Time = t_6

614 Cost of Upgrading Coal Liquids

Coal liquids are unsuitable for today's diesels and turbines because they contain larger amounts of impurities (especially sulfur and nitrogen) and contain more aromatics (therefore, less hydrogen) than current fuels. To find application in current engines the carbon to hydrogen ratio of the coal liquids will have to be reduced, i.e., hydrogen will have to be added, or the engines will require modifications, or perhaps both.

Proper evaluation of which alternative to choose requires the examination of relative costs. The intent here is to examine the cost* of upgrading coal liquids as a function of the product hydrogen level.**

6.14.1 Upgrading Cost and Weight Percent Hydrogen

In the mechanism used for approximating upgrading costs, this cost is assumed to be directly proportional to hydrogen consumption. The cost is composed of the following:

- a) The cost of hydroprocessing equipment (simulated by a conventional petroleum vacuum gas oil hydrocracker)
- b) The cost of producing the hydrogen
- c) The cost for handling crude and products plus primary distillation (as approximated by a conventional petroleum atmospheric pipestill of 150,000-barrels-per-day capacity)

A summary of these cost components follows:

Table 6-64	
<u>COAL LIQUIDS UPGRADING COST COMPONENTS (1980 \$)</u>	
Hydroprocessing	
- Equipment	0.28 \$ per pound of hydrogen
- Hydrogen	0.50 \$ per pound
Cost of handling crude, product and primary distillation	0.20 \$ per MBTU of crude feed

* Upgrading cost is defined as the sum of the cost for receiving, and handling crude and products plus primary distillation and hydroprocessing.

** Assumes that hydrogen content is a measure of fuel quality.

Hydrogenative upgrading is used not only to increase the hydrogen content of coal liquids, but also to reduce sulfur, oxygen, and nitrogen levels which are undesirable in synthetic crude oils. Hydrogen requirements are a function of coal liquids composition, which can vary significantly with both coal source and liquefaction process employed. To illustrate, the costs of upgrading two coal liquids of widely different compositions are shown in Figures 6-14 and 6-15.* The coal liquid composition is shown on each figure. The figures illustrate that upgrading costs increase with increasing levels of feed sulfur, nitrogen, and oxygen, decrease with higher feed hydrogen, and rise with increasing hydrogen content of the upgraded product. The 10 wt.% case will serve for purposes of discussion. The upgrading cost for current turbo engines, requiring 13.5 wt.% hydrogen, is about 1.80 \$/MBTU. If this requirement is reduced to 11.5 wt.% hydrogen, the corresponding upgrading cost is 0.95 \$/MBTU. Further reduction to 10 wt.% lowers the upgrading cost to 0.30 \$/MBTU.

The foregoing shows that definite incentives do exist for reducing engine fuel quality requirements; however, this must be balanced against the cost of the required engine modifications.

* The intersection of the 10 wt% hydrogen line with the cost axis at 0.30 \$/MBTU represents the minimum cost for producing a fuel at this hydrogen level, i.e., the cost for handling and primary distillation and impurity removal.

FIGURE 6-14

COAL LIQUIDS UPGRADING COST VS.
PRODUCT WEIGHT PERCENT HYDROGEN

(Base Content: 7 Wt%)

FIGURE 6-15

COAL LIQUIDS UPGRADING COST VS.
PRODUCT WEIGHT PERCENT HYDROGEN

(Base Content: 10 wt%)

6.15 Raw Shale Oil Upgrading Cost

Raw shale oil is much higher in nitrogen than typical petroleum crudes. For shale oil to be used as a conventional transportation fuel nearly all of this nitrogen must be removed so as to minimize NO_x emissions and avoid fuel instability. In addition, nitrogen acts as an inhibitor for conversion catalysts. Further, the refiner has the option of upgrading at the retort site to synthetic crude quality or to restrict field processing to the minimum required to make it suitable for pipelining (as produced the raw shale oil requires some pour point reduction for pipeline transportation). Weight percent nitrogen in the product provides a measure of the degree of upgrading. Stangeland and Sullivan (Ref. 6-26) have reported on hydroprocessing of shale to various product nitrogen levels. As one might expect, decreasing nitrogen level requires increasing hydrogen consumption as shown in Figure 6-16. In order to calculate the cost of upgrading to different product nitrogen levels, a system for estimating the cost has been developed. The cost of upgrading of raw shale liquids is assumed to be proportional to the hydrogen consumption. There are two components to this upgrading cost: the cost of hydrogen and the necessary hydrotreating equipment (as simulated by a conventional vacuum gas oil hydrocracking unit). The cost components follow in Table 6-66.

Table 6-65
SHALE LIQUID UPGRADING COST COMPONENTS (1980 \$)

Equipment	0.28 \$ per pound of hydrogen
Hydrogen	0.50 \$ per pound

Combining the information of Figure 6-16 and Table 6-66 a plot of upgrading cost versus product nitrogen level can be developed and is shown in Figure 6.17. The relationship between cost and nitrogen level follows a relatively smooth curve until about the 0.5 wt% level. Beyond this point the cost takes a very sharp upturn, so that upgrading below this level is incrementally more expensive than above 0.5 wt%.

Again, this is an approximate technique and true upgrading costs will be determined only when commercial plants are designed, built and operating experience obtained.

FIGURE 6-16

HYDROGEN CONSUMPTION VERSUS
PRODUCT NITROGEN
HYDROFINING OF WHOLE SHALE OIL WITH ICR 106

FIGURE 6-17

SHALE UPGRADING COST VS. PRODUCT
NITROGEN LEVEL

6.16 Possible Impact of Process Improvement on Cost of Hydrogen

With the cost to manufacture hydrogen from coal being fairly expensive, and the cost to produce hydrogen via electrolysis even higher, the question could be asked--does new electrolytic technology have the potential to reduce the cost of hydrogen substantially. As was pointed out in an earlier section a developmental process called Solid Polymer Electrolyte (SPE) electrolysis has the potential to reduce the cost from about \$20/MBTU with KOH electrolysis to \$13/MBTU with the SPE process. If the SPE process is proven viable, then the electricity cost required for hydrogen via this route to be competitive with coal derived hydrogen, would have to be 1.6 ¢/kwh or approximately 50% of the value used in this study. This figure (1.6 ¢/kwh) represents the rough equivalent to the sum of fuel plus operating costs in generating electricity without provision for capital recovery. Electricity at this cost level is not foreseen, at this time, to be available in the 1980-2000 time frame. Therefore, improvements in coal based technology would be needed to reduce the cost of hydrogen.

1.17 Broadcut Petroleum Jet Fuel

One area that is receiving attention as a means for increasing the availability of jet fuel from petroleum is the use of a broadcut fuel - increasing the final boiling point and reducing the initial cut point. A broadcut fuel does not increase petroleum supply, it increases jet fuel supply at the expense of something else - such as diesel fuel, chemical feedstocks, or home heating oil. Thus as petroleum resources diminish, it will be necessary to establish end use priorities (by market or non-market mechanisms). The purpose of this section is to give an idea of what changes in fuel properties and yields are possible if the fuel specifications are relaxed. While the examples apply to petroleum based fuels, similar changes would apply to a coal derived liquid or a shale oil based jet fuel.

Current Jet A and two possible alternative specifications (derived from the minutes of the "Jet Aircraft Hydrocarbon Fuels Technology Workshop") are compared with representative virgin crude fractions from South Louisiana and Prudhoe Bay in Tables 6-67 - 6-69.

The volume and quality of the jet fuel is directly related to the specific crude being processed. This examination is made without regard for competing non-aviation demands for the middle of the crude barrel. The aim is to illustrate theoretical yield and processing differences if jet fuel specifications are relaxed. Demands for diesel fuel, chemical feedstocks, and heating oil affect fuel availability. Thus, even though yield increases may be significant, the additional yield may not be readily available to the aviation industry.

6.17.1 Yields and Qualities

The yields and qualities shown in Tables 6-66-6-68 represent straight run pipestill product without consideration of downstream processing. For example hydrofining or aromatics extraction, which would alter chemical properties, such as sulfur, aromatics, etc. is not considered. These processes are assumed to have little effect on the volume of the kerosene or distillate cut. One important factor which is taken into account is that a refinery pipestill will not produce a perfectly fractionated cut. A normal sidestream is lower in fractionation quality when compared with a True Boiling Point distillation and so an illustration of the impact that improved fractionation has on the yield of specification fuel is also shown in Table 6-66 which compares a typical sidestream cut with 15/5 distillation.*

6.17.2 Effect of Improved Distillation

Improving fraction is one way to improve yield of a given product. Better fractionation can be achieved, for example, by increasing the reflux ratio, adding additional tower trays or increasing the stripping steam rate. In existing towers some of these methods of increasing yield are clearly impracticable. Even if technically possible, the suggested changes all represent increased energy consumption and thus increased cost, and have not been applied in actual practice due to economic limitations. The purpose in describing the effect of improved distillation is to illustrate the changes possible if the economics would favor this change.

The reference case in this study is shown in Table 6-66. The two crudes are fractionated into boiling ranges that meet most current Jet A specifications while maximizing yield. The final boiling point specification is slightly exceeded for the normal cut of South Louisiana. In addition, the Prudhoe Bay fraction would require treating to reduce aromatics content. For South Louisiana, the yield increases 34% (23.5 vol % to 31.5 vol %) and the final boiling point specification is also met. The Prudhoe Bay yield increases by 41 % (17.1 vol % to 24.1 vol %), but still requires treating for aromatics reduction. A summary of key qualities follows.

	Current Spec.	South Louisiana			Prudhoe Bay		
		320/510 (Normal)	300/550 15/5*	Percent Increase	330/508 (Normal)	300/550 15/5*	Percent Increase
Nominal Boiling Range, °F							
Yield, LV% on Crude	-	23.5	31.5	34	17.1	24.1	41
Aromatics, vol% (max)	20	15.1	15.3		23.9**	25.1**	
Final Boiling Point °F (max) 550		553**	550		550	550	

**Does not meet specification

*This is a laboratory distillation technique which provides fractionation equivalent to a column with 15 theoretical trays and a 5:1 reflux ratio.

Although the yield credits for improving fractionation are large, individual case evaluation of the cost for improving fractionation is required. The methods for better fractionation outlined above each carry associated costs. In addition, physical and economic constraints may inhibit their implementation. Existing units may not have capacity enough for increasing the number of trays and the additional expense for steam generation or more reflux may heavily debit the yield improvement. Grass roots design does present more opportunities for tighter fractionation, but the economic factors of additional investment and operating cost may outweigh the advantage of added product volume. Generalizations concerning fractionation improvement would be misleading. Suffice it to say that there is theoretical scope for higher yields of specification product, but practical limitations may prevent these yields from being realized.

6.17.3 Broadcut Implications on Yield and Quality

The first broad specification examined is shown in Table 6-67. Comparison with current specifications shows that the aromatics content will be higher, the boiling range wider, the gravity specification has increased and the viscosity is now measured at 100°F instead of -30°F. These changes result in increased yield. The normal South Louisiana recovery has increased by 50% over the normal cut for current specifications. The yields for Prudhoe Bay have also increased - the normal cut shows a 58% increase over the reference cut. However, as the table indicates, the relaxation of the aromatics content spec. eliminates the need for further treatment because the Prudhoe Bay quality now falls below the maximum. A key quality summary follows:

Nominal Boiling Range, °F	Broad Spec.	South Louisiana			Prudhoe Bay		
		290/570	320/510	Percent Increase	290/570	330/508	Percent Increase
Yield, LV% on Crude	-	35.2	23.5	50	27.1	17.1	58
Aromatics, vol% (max)	35	15	15		25	24	
Final Boiling Point °F (max)	600	603	553		606	550	

1.1744 Additional Broadcut Specification

A further relaxation in specification will increase the theoretical yield even more, as shown in Table 6-68. Here the allowable aromatics content is 40 vol%, the final boiling point 650°F, minimum flash 90°F, maximum flash 200°F, and the maximum viscosity at 100°F is 4 CS. The South Louisiana (normal fractionation) yield is 43.1 vol% - and 83% increase over the reference cut. The Prudhoe Bay yield is 33.4 vol% (normal) an increase of 95% over the reference normal cut. Unlike the reference cut, these Prudhoe Bay fractions do not require treating to meet the aromatics content specification. The following table summarizes important qualities.

Nominal Boiling Range, °F	Broad Spec.	South Louisiana			Prudhoe Bay		
		280/620	320/510	Percent Increase	280/620	330/508	Percent Increase
Yield, LVZ on Crude	-	43.1	23.5	83	33.4	17.1	95
Aromatics, vol% (max)	40	15	15		26	24	
Final Boiling Point °F (max)	650	648	553		650	550	

In summary, relaxation of jet fuel specifications will lead to higher yields of this product. Competing demands for the middle of the crude barrel will have to be evaluated in order to determine the total impact of maximizing jet fuel yield. In addition, broader specifications may eliminate the need for some downstream processing, thereby reducing cost.

In addition, the production of broad cut fuels can impact directly on both refinery and end-use energy consumption. Anderson (Ref. 6-27) in studying highway transportation has reported that process energy savings of 1 to 3 percentage points can be attained when producing a broad cut fuel roughly equivalent to equal parts of gasoline and diesel fuel. Also, Anderson indicates increased engine efficiency for the broadcut fuel. Thus, there is scope for increasing the composite production/use fuel system in the broadcut option. However, he points out that these data are very preliminary and require further study for confirmation.

Even though yield increases may be significant, the additional yield may not be available to the aviation industry, because of competing demands for liquid fuels.

TABLE 6-66

COMPARISON OF CURRENT JET A FUEL SPECIFICATIONS WITH
VIRGIN CUTS OF SOUTH LOUISIANA AND PRUDHOE BAY CRUDES

		<u>Current Jet A Specification</u>	<u>South Louisiana</u>		<u>Prudhoe Bay</u>	
Nominal Boiling Range, °F			320/510	300/550	330/508	300/550
Fractionation			(Normal)	(15/5*)	(Normal)	(15/5*)
LV% on Crude			23.5	31.5	17.1	24.1
<u>Composition</u>						
Aromatics (vol%)	Max	20	15.1	15.3	23.9	25.1
Sulfur, Merc. (wt%)	Max	0.003	0.0008	0.0009	0.0003	0.0004
Sulfur, Total (wt%)	Max	0.3	0.045	0.052	0.137	0.162
Nitrogen, Total (wt%)	Max	-	0.000	0.001	0.000	0.000
Hydrogen (wt%)	Max	-	13.2	13.2	12.9	12.8
<u>Volatility</u>						
<u>Distillation</u>						
Temp., °F	10% Rec.	Max	400	344	334	349
	50% Rec.	Max	450	430	446	425
	Final B.P.	Max	550	553	550	550
Flash Point, °F	Min-Max	105-150	104.7	108.2	109.5	108.2
Gravity, API (60°F)	Min-Max	39-51	41.2	40.6	38.9	38.5
Gravity, Specific (60/60°F)	Min-Max	0.7753-0.8299	0.819	0.822	0.830	0.832
<u>Fluidity</u>						
Freezing Point, °F	Max	-40	-55.5	-48.0	-41.6	-35.0
Viscosity @ -30°F, CS	Max	15	7.0	15.0	6.1	11.8
@ 100°F, CS	Max	-	1.6	1.8	1.6	1.6
<u>Thermal Stability @ 300/400°F</u>						
Coker ΔP in Hg	Max	12				
Coker Tube Color Code	Max	3				
<u>Combustion</u>						
Net Heat, Btu/lb	Min	18,400	18,500	18,500	18,500	18,500

* A laboratory distillation technique which provides fractionation equivalent to a column with 15 trays and 5:1 reflux ratio.

TABLE 6-67

COMPARISON OF A POSSIBLE BROAD JET FUEL SPECIFICATION WITH
VIRGIN CUTS OF SOUTH LOUISIANA AND PRUDHOE BAY CRUDES

		<u>Possible Broad Specification</u>	<u>South Louisiana</u>	<u>Prudhoe Bay</u>
Nominal Boiling Range, °F			290/570	290/570
LV% on Crude			35.2	27.1
<u>Composition</u>				
Aromatics (Vol%)	Max	35.	15.0	24.8
Sulfur, Merc. (wt%)	Max	0.003	0.0009	0.0004
Sulfur, Total (wt%)	Max	0.3	0.056	0.195
Nitrogen, Total (wt%)	Max	0.005	0.001	0.002
Hydrogen (wt%)	Min	13.0	13.3	13.0
<u>Volatility</u>				
Distillation				
Temp., °F 10% Rec.	Max	420	329	324
50% Rec.	Max	470	453	443
Final B.P.	Max	600	603	606
Flash Point, °F	Min-Max	90-170	94.3	93.1
Gravity, API (60°F)	Min-Max	36-51	40.3	38.1
Gravity, Specific (60/60°F)	Min-Max	0.7753-0.8448	0.824	0.834
<u>Fluidity</u>				
Freezing Point, °F	Max	-20	-40.0	-25.3
Viscosity @ -30°F, CS	Max	-	8.9	7.5
@ 100°F, CS	Max	3	1.9	1.7
<u>Thermal Stability @ 250/350°F</u>				
Coker ΔP in Hg.	Max	12		
Coker Tube Color Code	Max	3		
<u>Combustion</u>				
Net Heat, Btu/lb	Min	18,300	18,500	18,450

TABLE 6-68

COMPARISON OF A POSSIBLE BROAD SPECIFICATION WITH
VIRGIN CUTS OF SOUTH LOUISIANA AND PRUDHOE BAY CRUDES

		<u>Possible Broad Specification</u>	<u>South Louisiana</u>	<u>Prudhoe Bay</u>
Nominal Boiling Range, °F			280/620	280/620
LV% on Crude			43.1	33.4
<u>Composition</u>				
Aromatics (Vol%)	Max	40	15.0	26.0
Sulfur, Merc. (wt%)	Max	0.003	0.0009	0.0003
Sulfur, Total (wt%)	Max	0.3	0.069	0.275
Nitrogen, Total (wt%)	Max	0.005	0.001	0.005
Hydrogen (wt%)	Min	12.5	13.4	13.0
<u>Volatility</u>				
Distillation				
Temp., °F 10% Rec.	Max	450	328	323
50% Rec.	Max	550	474	467
Final B.P.	Max	650	648	650
Flash Point, °F	Min-Max	90-200	94.6	93.5
Gravity, API (60°F)	Min-Max	32-51	39.3	36.9
Gravity, Specific (60/60°F)	Min-Max	0.7753-0.8654	0.829	0.840
<u>Fluidity</u>				
Freezing Point, °F	Max	0	-25.7	-8.3
Viscosity @ -30°F, CS	Max	-	11.7	10.2
@ 100°F, CS	Max	4	2.1	2.0
<u>Thermal Stability @ 250/350 °F</u>				
Coker ΔP in Hg.	Max	12		
Coker Tube Color Code	Max	3		
<u>Combustion</u>				
Net Heat, Btu/lb	Min	18,200	18,500	18,400

6.18 Processing of Shale Oil and Coal Liquids in a Petroleum Refinery

When shale oil and coal liquids are produced they could be refined in a separate facility or used as feedstocks in existing refineries. The latter case is the most likely situation. In this case, it is important for this study to know if the coal or shale oil liquids will end up in jet or diesel fuel or will the synthetics displace petroleum fractions from heavier products and thus only petroleum fractions will end up in these two particular products. It is also important to have an idea of how much coal or shale oil liquids can be run in existing refineries with existing conversion equipment. Two engineering planning studies have been made previously by Exxon Research & Engineering that addressed these questions. The conclusions from these studies are covered in the following sections.

6.18.1 Processing of Shale Oil Liquids

An engineering planning study was made of the effect of processing shale oil in a refinery processing both shale oil and petroleum to a full product slate including jet fuel (Ref. 6-28). The study which involved a number of arbitrary but well-defined assumptions, was done in the context of a grass roots refinery processing raw shale oil and petroleum in segregated operations. Shale oil processing was restricted to distillation and hydrotreating of the kerosene and gas oil fractions, whereas petroleum processing involved a full spectrum of refinery processes with a relatively high level of conversion of heavier fractions to lighter fractions to meet a high motor gasoline demand. Conversion processing options for shale oil fractions were specifically excluded due to a lack of such data available to the program. The hydrotreated shale kerosene was blended to jet fuel product and the hydrotreated shale vacuum gas oil and untreated vacuum resid were blended into fuel oil or liquid plant fuel displacing petroleum fractions which are in turn converted to lighter products. Shale oil was incrementally introduced into the refinery which was initially processing 100 kb/CD of petroleum crude while the refinery was constrained to produce the same volume of prime products.

6.18.1.1 Conclusions

The major conclusions of the study are as follows:

- Shale oil may be used to replace or supplement petroleum crude and still meet historical jet fuel demands.
- Jet fuel yield per barrel of shale oil is low. The principal mechanism for producing incremental jet fuel from shale oil is to have shale fuel oil and distillate fractions replace petroleum fractions as fuel oil flux, thereby freeing heavier petroleum fractions for use as conversion process feed.

- The volume of shale oil that may be run is limited by the availability of fuel oil outlets and the unavailability of conversion outlets for shale oil.
- A program of developing data on conversion of shale fuel oil fractions should be pursued.

6.18.1.2 Discussion

It is likely that as shale oil comes into significant commercial production, it will be processed in conventional petroleum refineries along with petroleum crudes rather than in refineries designed specifically for shale oil refining. This approach will minimize the processing required to produce salable products from shale oil as well as reduce the performance and quality risk normally associated with the introduction of new products. Shale oil production will most likely reduce foreign crude imports otherwise needed to meet increasing product demand in the U.S.

The study was done with the aid of a refinery, linear programming, computer model. Linear programming (LP) is a mathematical technique for finding the optimum configuration of a complex system. LP is widely used throughout the petroleum industry as well as other industries. As applied to this situation LP was used to define the optimum refinery processing sequence for both petroleum and shale oil consistent with product demand, crude availability, product quality, heat and material balance constraints.

The Base Case for the study was a grass roots refinery producing 100 kB/CD of liquid product (97.5 kB/CD of prime product - i.e. ex LPG) according to the base demand pattern of PAD II by processing a 100% petroleum crude slate (67/33 So. Louisiana/Arabian Light) in refining facilities typical of PAD II.* The product yield is shown below:

Motor Gasoline	58.0 kB/CD
Jet Fuel**	5.0 kB/CD
Distillate	23.5 kB/CD
Fuel Oil	<u>11.0 kB/CD</u>
Total Prime Product	97.5 kB/CD

* Selection of petroleum crude slate and PAD II refining facilities was arbitrary. While the results may not therefore be generalized, they do illustrate how shale oil liquids may be refined in existing facilities.

** "Jet Fuel" represents a 4/1 combination of Jet A/JP-4.

Increments of raw shale oil were brought into the crude slate, replacing Arabian Light crude, while the refinery was forced to meet the same prime product demand as the Base Case. Production of LPG and refinery fuel gas, both relatively low volume products, was allowed to vary. This resulted in a series of cases with an ever increasing volume of shale oil in the crude slate. Since, in this study, shale oil fractions boiling above 500°F cannot be converted to lighter products, there is a practical limit as to how much shale oil may be introduced into the crude slate. This limit was reached when virtually all of the fuel oil and plant fuel demand had been satisfied by shale oil derived fuel oil. The limit was approximately 16 kB/CD (per 100 kB/CD of product).

The study does not assess the possibility of making diesel fuel from fractions boiling in the distillate range of shale oil, which contain substantial amounts of oxygen, nitrogen, and sulfur. It should be possible to select hydrotreating conditions for making a stable product meeting current cetane number specifications. The yield may be restricted by pour point.

6.18.2 Processing Coal Liquids

Economic studies have been made at Exxon Research and Engineering on the preferred route for converting coal liquids to lighter products and to evaluate coal liquids as a refinery feedstock in comparison to Arabian Light crude. The selection of a particular crude and refinery configuration will vary from company to company. The cases covered here were of specific interest to Exxon, but the conclusions are included because they may be helpful, fully realizing that the results may not be of a general nature.

The studies indicated that up to 25% petroleum can be replaced by coal liquids in a typical refinery. Only the naphtha fraction of the coal liquids will be used in transportation fuel blends, and the 350°F+ fractions are incorporated in heating oil and low sulfur fuel oil. The study assumed that the pipestill fractions from coal liquids would be segregated from petroleum fractions either by using separate distillation facilities or by blocked operations. The study suggests that a coal liquefaction plant may sell its 400°F- product to a refinery for upgrading to gasoline and heating oil and sell 400°F+ product directly to consumers in the utility and industrial sectors.

Using a proprietary linear program model two coal liquids from the EDS coal liquefaction process were evaluated in 100 kB/D grass roots refineries running mixtures of EDS coal liquids and Arabian Light petroleum crude. The overall conclusion of the study was that the most economical way to utilize coal liquids is by blending them directly into heating oil and fuel oil products and to increase the conversion of heavy petroleum fractions to maintain gasoline and distillate production. Specific conclusions are as follows:

- Coal liquids are worth up to 2\$/Bbl more than the Arabian Light crude (@ 12.50\$/Bbl) they displace when they constitute 25% or less of total crude input.

- Upgrading the 450°F+ fraction by hydrotreating in the liquefaction plant did not increase the value of coal liquids.
- Catalytic reforming of the 350°F- naphtha provided high yields of hydrogen and high octane gasoline.
- Coal liquid fractions boiling above 350°F had a high values as 0.7% sulfur fuel oil due to their low sulfur content and high volumetric heat content.
- There are substantial disincentives for converting 350°F+ coal liquids by either catalytic cracking or hydrocracking.
- The 350°F+ coal liquids should be utilized as low sulfur fuel oil or heating oil, displacing petroleum fractions to catalytic cracking feed.

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Table 6-69

LOWER HEATING VALUES OF FUELS

Fuel Oil	6.05	MBTU/Barrel
Shale Liquids	5.3	"
Coal Liquids	5.8	"
Oil from Organic Waste	5.8	"
Ammonia	16.1	MBTU/Ton
Ethanol	23.0	"
Methanol	17.1	"
Coal/Oil Slurry	33.9	"
Acetylene	20,730	BTU/Pound
Hydrazine	7,294	"
Methylamine	13,285	"
Coal		
High Sulfur	11,975	BTU/Pound
Low Sulfur	8,050	"
SNG	870	BTU/SCF
LBG	180	"

7. TRANSPORTATION, DISTRIBUTION AND STORAGE COST OF ALTERNATE FUELS

E. N. Cart, Jr.

7.1 Introduction and Summary

In addition to considering the economics of manufacture of the various alternate fuels, it is also necessary to consider the cost of transportation, storage, and distribution associated with moving the fuels to the customer. In most cases, the raw material resources are not located near the markets, so a large transportation network is required to move the resource to the conversion site and ultimately to the customer.

There are two basic types of energy movement considered--transportation and distribution. Transportation refers to movement of energy over long distances, generally between a single source and a single destination, usually interregional. Transportation also generally refers to large scale energy transmission with high load factors. Distribution describes how energy is delivered from a large terminal to the customer. Typically, the distance will be short (intraregional), there will be many destinations, and the load factor will be low, designed for peak demands. Typically, also, there are storage facilities at distribution terminals.

A typical transportation system for petroleum from the oil well to the refinery is shown in Figure 7-1. The transportation/distribution system for petroleum products for aircraft, marine, and rail are shown in Figure 7-2. The products move from the refinery by either pipeline, tanker/barge, or rail car to a marketing storage terminal. Most of these storage facilities have a capacity of more than 2 million gallons. In the case of aircraft fuels, the products move by tank truck, rail, or pipeline to tankage at the airport. From tankage, the fuel moves either by truck or through a hydrant system to the aircraft. For marine fuels, the products move to the vessel via a barge that services the ships in a harbor or by trucks that service the vessels at the dock. The products can also move by various means to smaller bulk plants that are used to supply small scale operations, such as pleasure crafts. The railroads generally pick up their fuel from major marketing terminals and move the products by rail to their own tankage.

The method of selecting how the products move from refinery to bulk terminal to the customer's tankage depends on a number of factors. The method of transporting refined petroleum products in 1974 was fairly equally divided among pipelines, water carriers, and trucks, as shown below:

Transporting Refined Petroleum Products (wt. %) (7-23)

Water Carriers	25.8%
Pipelines	33.5
Trucks	38.5
Rail	2.2

FIGURE 7-1MAIN ELEMENTS OF TRANSPORTATION,
STORAGE AND DISTRIBUTIONConventional Petroleum

FIGURE 7-2

TYPICAL TRANSPORTATION/DISTRIBUTION SYSTEMS FOR PETROLEUM PRODUCTS

While rail accounts for only a small percentage of the movement of refined products, it is an important method of supplying fuel within the railroad industry.

In the following sections, the transportation costs for the different alternate fuels and for various modes of transmission (pipeline, rail, barge, truck) are summarized and put on a common basis. The costs are expressed on a dollars per million BTU per 1000 mile basis. The storage and distribution costs are also covered for the major fuels of interest. To arrive at the estimated cost of the fuel delivered to the customer, it is necessary to make some assumptions on representative distances. Actual transportation and distribution costs can vary from the values shown, depending on shipping distance, terrain, tariff rates, etc. The transportation distance assumed for this comparison has been arbitrarily set at 1000 miles in most cases. The coal and shale oil liquids have an additional 500 mile product pipeline cost added to move the product from a refinery to a bulk terminal. For some of the unconventional fuels, the processing plants may be smaller and located nearer to the point of use. Sufficient information is given in later sections to permit adjustments to a different basis. Table 7-1 summarizes the total delivered cost for some of the various alternate fuels. The costs are divided into four major areas--feedstock or raw material costs, manufacturing costs, upgrading costs (includes liquefaction cost for hydrogen and methane), and transportation and distribution costs. The costs have been rounded to the nearest $\$0.05/10^6$ BTU which accounts for some of the numbers being slightly different from that number shown in other sections. The detailed basis for each fuel is described in the following sections. Several interesting facts are apparent from Table 7-1 from the standpoint of the transportation and distribution costs.

- Transportation costs can be a significant cost in using coal as a fuel directly or in contributing to the total feedstock cost of a coal-based alternative fuel.
- Transportation and distribution costs represent around 7-8% of the total delivered cost of coal liquids.
- Transportation and distribution costs represent 5-22% of the total delivered cost for shale oil, methanol, and ethanol.
- Transportation and distribution costs for hydrogen, methane, ammonia and acetylene represent 10-26% of the total delivered cost.
- The transmission and distribution costs for electricity represent around 35% of the total cost for large commercial users.

This type of ranking indicates where additional research and development may be useful in reducing the overall cost of delivery of some of these fuels to the consumer.

7.2 Coal Transportation Costs

Coal can be transported by rail (unit train or conventional), slurry pipeline, or barge. For short hauls, trucks or conveyors could also

TABLE 7-1

SUMMARY OF TOTAL DELIVERED COST OF ALTERNATE FUELS\$/10⁶ BTU (1980 Cost)

<u>Fuel</u>	<u>Feedstock or Raw Material</u>	<u>Manufacturing Cost</u>	<u>Upgrading Costs</u>	<u>Fuel Transportation and Distribution</u>	<u>Total Cost</u>	<u>Transportation/ Distribution-- % of Total</u>	<u>Details in Figure</u>
Coal--Eastern	0.60-1.30	--	--	0.30(1)	0.90-1.60	19-33	
--Western	0.30-0.70	--	--	0.75(1)	1.05-1.45	52-71	
Coal/Oil Slurry	2.45	0.35	--	(2)	2.80	--	7-3
Coal Liquids	1.20-1.70	2.60-4.60	1.60-2.70	0.50-0.65	5.90-9.90	7-8	7-5
Shale Oil Liquids	2.50	1.70-1.90	0.00(7)	0.50-0.70	4.70-5.10	11-14	7-6
Methanol	1.70-2.15	5.00-9.05	--	1.10-3.20	7.80-14.40	14-22	7-8
Ethanol	9.00-13.50	7.70 ⁽⁵⁾	--	0.85-2.40	17.55-23.60	5-10	7-9
Hydrogen	1.70-1.80 ⁽⁴⁾	6.20-7.90	4.90 ⁽⁶⁾	3.80-4.80	16.10-18.90	23-25	7-11
Methane	1.90-2.70 ⁽⁴⁾	4.20-6.05	2.00 ⁽⁶⁾	1.6-1.8	9.70-12.55	13-19	7-13
Ammonia	2.20-2.30 ⁽⁴⁾	10.10-10.60	--	3.80-4.20	16.10-17.10	24-25	7-15
Acetylene	1.85 ⁽⁴⁾	12.15	--	>4.60	>18.65	~25	7-16
Hydrazine	>37	?	--	>3.25	>>40		7-17
Electricity	3.4	6.20	--	5.3	14.9	36	7-18

(1) 500 miles for Eastern coal and 1000 miles for Western coals.

(2) Included in feedstock in raw material costs.

(3) Upgraded to 13.5% hydrogen in distillate.

(4) Eastern coal based production. Plant at mine mouth.

(5) Corn resource base.

(6) Liquefaction cost.

(7) Covered in manufacturing cost.

be used. The relative economics of the various modes of transporting coal vary depending on utilization of the facilities, the distance the coal is to be moved, terrain, coal density, car and train size in the case of unit trains, and train speed. A study by Nagarvala⁽⁷⁻²⁰⁾ shows how the unit rate can vary with transportation distance.

A summary of coal transportation costs for a unit train, a water slurry pipeline, and barge movements is shown in Table 7-2. All data have been adjusted to 1980 dollars, using the same economic basis described in Table 6-4. The costs are shown as dollars per million BTU per 1000 miles. Since most of the literature reported the costs on a cents/ton-mile basis, it was necessary to assume an average heating value of Western and Eastern coals to convert this to a cents/million BTU basis. The values assumed are 24.0×10^6 BTU/short ton for high sulfur coal (assumed to be Eastern coal) and 16.1×10^6 BTU/short ton for low sulfur coal (assumed to be Western coal). As shown in Table 7-2, there is a range of coal transportation costs. The values that will be used in this study are shown at the bottom of the table.

Since coal can be a basic resource for several alternate fuels, there are several ways to move the coal from the mine to the conversion plant, with some of the methods depending on whether the conversion plant is located at the mine mouth or near the demand center. From an economic standpoint, mine mouth conversion plants are usually favored since the cost of pipeline transportation of the liquid products usually are lower than the cost of moving the coal long distances. However, the environmental and socioeconomic impacts of locating several large coal conversion plants in the arid and rural West may force the conversion plants nearer the demand center. The question of rail versus slurry pipeline is beyond the scope of this study. Rieber, et al⁽⁷⁻¹⁰⁾ have made a detailed comparison on the future of coal transportation, looking at unit trains, slurry pipeline and high pressure pneumatic pipeline. That study concluded that slurry pipelines and unit trains are competitive.⁽⁷⁻¹⁰⁾

7.3 Coal/Oil Slurry Transportation

One of the alternate fuels being considered for a non-highway transportation fuel is a colloidal blend of coal and oil. The overall production, transportation and distribution system is shown in Figure 7-3. It is assumed that the coal and oil would be delivered separately to the customer and a 25 KT/D grinding and blending facility would be used to blend the two components.

Eastern coal at \$21/ton at the mine is moved 1,000 miles by unit train to the grinding and blending plant. Other combinations of coal type and distances could apply as well. The oil cost at the point of blending is assumed at around \$20/B. A blend of 40% by weight coal and 60% by weight oil is assumed. Grinding and blending costs add \$0.35/ 10^6 BTU to the total fuel cost of \$2.80/ 10^6 BTU.

TABLE 7-2SUMMARY OF COAL TRANSPORTATION COST

1980 Dollars

\$/ 10^6 BTU per 1000 miles24.0 x 10^6 BTU/St - Eastern Coal16.1 x 10^6 BTU/St - Western Coal

Ref.	Unit Train		Slurry Pipeline		Barge
	Western	Eastern	Western	Eastern	Eastern
7-1	0.75	0.65	1.31	0.87	0.27
7-6	0.69-0.86	0.46-0.57	0.43-0.60	0.29-0.40	
7-7	0.86	0.91	0.82	0.54	0.49
7-8	0.47-0.64	0.30-0.41			
7-9	0.64	0.64	0.73		0.18
7-10	0.58	0.37			
7-11	1.23	0.79			
7-20	0.90	0.58	0.64-1.01	0.41-0.65	0.22-0.34
7-22	0.78	0.50	0.67	0.43	0.21-0.33
7-34	0.60-1.00	0.4-0.7	0.6-1.2	0.4-0.8	0.1-0.3
Used in this study	0.75	0.65	0.75	0.65	0.27

FIGURE 7-3

COAL/OIL SLURRY PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

7.4 Coal Liquids

7.4.1 Transportation Costs

It is assumed that any coal liquids would move by pipeline from the liquefaction facilities to a refining center. The cost of moving liquids by pipeline will depend on the shipping distance, volume pumped, type and number of products handled, liquid viscosity, terrain to be crossed, size of line, etc. Table 7-3 summarizes the literature data on the cost of moving crude and distillate by pipeline. The literature data have been converted to 1980 dollars using a 7% per year inflation rate. In some cases, a capital recovery factor of 15% from the literature has been retained rather than adjust to the higher recovery rate used for the liquefaction plant.

A study by Nagarvala, et al⁽⁷⁻²⁰⁾ derived the cost of inter-regional pipeline transportation costs for crude oil pipeline and product pipelined, as a function of pipeline carrying capacity (pipeline size). The cost of moving liquids in a crude pipeline as a function of pipeline capacity is shown in Figure 7-4, calculated from the equation in Reference 7-20. A 15% capital recovery factor is assumed in the cost shown in Figure 7-4. The other data are shown for comparison, and are in general agreement. It would appear the cost calculated from Reference 7-40 may be about 15-20% lower than the other data. For this study, it has been decided to use the higher cost, as shown in Figure 7-4.

One of the major questions that will need to be answered is: Can or will coal liquids be added to existing crude supply lines or will it be necessary to build separate pipelines to move the coal syncrude to a refinery for processing? If a separate line is built, the size would be much smaller, and result in a higher transportation cost, than if the existing crude distribution system with 600-800,000 B/D capacities were used.

7.4.2 Storage and Distribution Costs

It is assumed that after the coal syncrude is upgraded, the distillate and fuel oil product would be handled in the same manner as petroleum products are currently distributed. Thus, the products would move from the refinery by a product pipeline to a large terminal and from the terminal by tank truck, rail or barge or smaller pipeline to the customer's tankage. It is difficult to arrive at a good estimate of the cost of distribution of products due to the wide variation in distances, flow rates and mode of transportation involved.

For the product pipeline costs, the data reported by Nagarvala, et al., shown in Figure 7-4, will be used. An average flow rate of 100×10^3 B/D will be assumed, which is typical for a 14-inch diameter pipeline. An average distance of 500 miles will be assumed between the refinery and the bulk terminal. The actual distance can vary considerably, but this average value will be assumed for this study. With these assumptions, the pipeline cost would be around \$0.10/10⁶ BTU in terms of 1980 dollars. This is in line with the cost reported by Grigsby, et al⁽⁷⁻²¹⁾ for the cost to move products by pipeline from a refinery to a terminal.

TABLE 7-3SUMMARY OF COAL LIQUIDS PIPELINE COST

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/10⁶ BTU per 1000 Miles</u>	<u>Comments</u>
7-1	0.095	30-inch diameter line, 600,000 B/D for crude and distillate.
7-6	0.12	Assumes coal liquid of 5.8 x 10 ⁶ BTU/B and 15° API to convert from cents per ton mile to \$/10 ⁶ BTU/mile.
7-9	0.07-0.09	
7-11	0.16 0.24	14-inch diameter--100,000 B/D 10-inch diameter-- 50,000 B/D
7-19	0.09	
7-20	0.08 0.22	36-inch diameter--800,000 B/D 12-inch diameter--product pipeline

FIGURE 7-4

COST OF MOVING CRUDE BY PIPELINE
(CRUDE, COAL LIQUIDS OR SHALE OIL SYNCRUDE)

The distribution cost for petroleum products has been reported by Grigsby, et al.(7-21) The cost for distribution of petroleum products in terms of 1980 dollars is shown below. For this study, the same average cost used by Grigsby will be used, but the range is also shown.

	<u>\$/B (1980 Dollars)</u>	<u>Range-\$/B</u>
Terminal Operating Cost	0.19	0.04-0.37
Marketing Cost	0.78	0.32-1.56
Truck to Customer	0.63	0.31-1.56
Capital Recovery at 35% (Terminal and Truck)	<u>0.14</u>	<u>0.14</u>
	1.74	0.81-3.63

On a BTU basis, the average cost is \$0.31/10⁶ BTU for coal-derived distillates. This cost is lower than it would be for gasoline, since the operating cost of the service station and capital recovery would add another \$1.28/10⁶ BTU to the cost of distributing gasoline in a retail operation.

7.4.3 Total Delivered Cost to Customer

A total production, transportation and distribution system for coal liquids is shown in Figure 7-5. The costs shown are for an Illinois coal, with the liquefaction plant located at the mine with coal movement 10 miles by truck or conveyor. It is also possible that the liquefaction facilities could be located several hundred miles from the mine, in which case the coal transportation would be by unit train or slurry pipeline and could add about \$0.5/10⁶ BTU to the total cost if the distance was 500 miles. Another alternate would be for the coal syncrude to be from Western coal, with the liquefaction plant either in the mine site or located in the Midwest. If the Western coal is transported 1000 miles, the coal transportation cost could be in the \$0.7-1/10⁶ BTU range.

Estimates of liquefaction cost vary considerably, depending on the type of product produced, the process used and degree of detail information available for the cost estimates. Section 6.5 describes the various types of processes and the range of cost for a syncrude from coal. A typical liquefaction process has been used in Figure 7-5 to show the cost of producing distillates from coal. The coal liquefaction cost of \$2.55-4.60/10⁶ BTU is in the range of several of the processes under consideration for further development (H-coal, Exxon EDS, SRC-II).

The cost to move the syncrude to a refinery will not be a significant cost; around \$0.10/10⁶ BTU if a large size pipeline (500 KB/D) can be used and \$0.24/10⁶ BTU if the flow rate is only around 50 KB/D. The assumed distance in both cases is 1000 miles.

The refinery upgrading cost of \$1.60-2.70/10⁶ BTU is a rough estimate of the cost to provide distillate from coal liquids. The distillate has been upgraded to 13.5% hydrogen.

FIGURE 7-5

COAL LIQUIDS PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

The basis for the product pipeline and distribution costs are described in Section 7.4.2. As can be seen, the overall transportation and distribution costs represent only about 7% of the total costs of coal liquids delivered to the customer.

7.5 Shale Oil Liquids

7.5.1 Transportation Costs

The most economical method for moving shale oil liquids would be by pipeline. However, crude shale oils have a high viscosity and pour point, which will require some pretreatment before the product can be moved in conventional, unheated pipelines. Railroad tank cars and tank trucks with heating coils could be used to move the crude shale oil, but the cost would probably be excessive. For this study, it is assumed that the raw shale oil will be partially refined at the retort to decrease the pour point. The cost of moving liquids shown in Figure 7-4 will be used for this study. Difference in gravity and heating value of the shale oil compared to coal liquids are neglected since the difference is on the order of \$0.01/10⁶ BTU per 1000 miles.

7.5.2 Storage and Distribution Costs

It is assumed that after the shale syncrude is upgraded, the distillate and fuel oil products would be handled in the same manner as petroleum products are currently distributed. Thus the products would move from the refinery by a product pipeline to a large terminal and from the terminal by tank truck, rail or barge or smaller pipeline to the customer's tankage. It is difficult to arrive at a good estimate of the cost of distribution of products due to the wide variation in distances, flow rates and modes of transportation involved.

For the product pipeline cost, the data reported by Nagarvala, et al shown in Figure 7-4 will be used. An average flow rate of 100×10^3 B/D will be assumed, which is typical for a 14-inch diameter pipeline. An average distance of 500 miles will be assumed between the refinery and the bulk terminal. The actual distance can vary considerably, but this average value will be assumed for this study. With these assumptions, the pipeline cost would be around \$0.10/10⁶ in terms of 1980 dollars. This is in line with the cost reported by Grigsby, et al (7-21) for the cost to move products by pipeline from a refinery to a terminal.

The distribution cost for liquid products was covered in Section 7.4.2 for coal liquids. The cost for distributing shale oil derived liquids would be about the same cost—\$0.3/10⁶ BTU.

7.5.3 Total Delivered Cost to Customer

The total production, transportation and distribution costs for shale oil liquids is summarized in Figure 7-6. The resource cost is based on \$0.2/10⁶ BTU for lease cost, but could be higher. The product upgrading, which would occur at the production site, would produce a syncrude that could be pumped in a conventional crude pipeline. For purposes of this

FIGURE 7-6

SHALE OIL LIQUIDS PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

study, it is assumed that the crude would move 1000 miles to a refinery for further upgrading. The range of $\$0.1-0.25/10^6$ BTU reflects a pipeline capacity of 500 KB/D to 50 KB/D.

The refining cost for shale oil derived distillate was discussed in Section 6.3.3. In this particular example, distillate is made by substituting cat cracking for hydrocracking and running more syncrude. In this case, the added operating costs are essentially zero since the savings for substituting a less costly conversion step offsets the cost of running more feed. Also, the addition of hydrogen to remove sulfur and nitrogen was done in the product upgrading step.

The product pipeline cost is based on moving the product in a 14-inch diameter pipeline, an average distance of 500 miles to a bulk terminal. The total distribution cost is based on the study by Grigsby(7-21) for petroleum products.

The total cost of any shale oil-derived distillate is about 90% associated with mining, product upgrading and refining, and 10-15% associated with transportation and distribution.

7.6 Methanol

7.6.1 Transportation Costs

Methanol has long been a basic, tonnage petrochemical and distribution by all means has been fully developed. Due to the lower specific energy of methanol, compared to petroleum products, the transportation cost per MBTU for methanol will be approximately double that for transporting petroleum products. A summary of the costs associated with the various methods of transporting methanol are given in Table 7-4. The lowest cost way to transport large volumes of methanol would be by pipeline. The estimated relationship between pipeline costs and capacity for methanol is shown in Figure 7-7, based on the curve shown in Figure 7-4, adjusted for the net heating value difference between petroleum products and methanol.

The location and number of plants near the pipeline would determine the size and capacity of the system. For example, it would take eight (8) 2000 T/D methanol plants to feed a pipeline with a 100,000 B/D capacity. Since it seems unlikely that this many plants would be in one location, a pipeline transportation cost of $\$0.8-1.00/10^6$ BTU-1000 miles seems like a more likely range (1-2 plants).

The transportation cost by tanker is for moving methanol from the Gulf Coast to the East Coast. Another alternative would be to convert natural gas in the Middle East to methanol for use in the U. S. Since this study is concerned with domestic supplies of energy, this alternate is not being considered.

The methanol could also be transported by rail. Rates are shown for a unit train and a conventional train, based on rail rates given in

TABLE 7-4SUMMARY OF METHANOL TRANSPORTATION COST

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/106 BTU per 1000 Miles</u>	<u>Mode</u>	<u>Comments</u>
7-1	0.18	Pipeline	600,000 B/D rate, 30-inch diameter line
7-1	0.63	Alaska Pipeline	48-inch diameter line
7-2	0.93	Pipeline	210,000 B/D rate, 20% capital recovery factor
7-3	0.78	Pipeline	Same as Ref. 7-2 except 15% capital recovery factor
7-19	0.27	Pipeline	--
7-1	0.26	Tanker	35 MDWT U. S. built and flag tanker, moving 888, 300 long tons per year over a trading distance of 2000 miles
7-19	1.18	Unit Train	Details not given on train size
7-7	1.21	Unit Train	Based on 1.5¢/ton mile in 1975 dollars for 1000 miles and 25 million tons per year
7-7	2.43	Conventional Train	Based on 3¢/ton-mile in 1975 dollars
7-7	0.69	Barge	Based on \$0.85/ton-mile

FIGURE 7-7

COST OF MOVING ALCOHOLS BY PIPELINE
(BASED ON FIGURE 7-4, ADJUSTED FOR HEATING VALUE)

Reference 7-7 of 1.5 and 3¢/ton-mile in 1975 dollars for coal. The rates shown in the table have been adjusted to 1980 dollars and to reflect the difference in weight and heating value between coal and methanol. Another mode of transportation would be to move the methanol by barge. This rate is estimated based on information in Reference 7-7 for coal.

7.6.2 Storage and Distribution Cost--Methanol

The distribution system for methanol will be somewhat different than the shale or coal liquids system described in previous sections since the methanol does not require refining and can go directly from the synthesis plant to the bulk terminal. The lower energy density of methanol relative to hydrocarbon will mean that roughly twice the amount of methanol has to be distributed for the same energy output as coal or shale liquids. In addition, the initial distribution system will likely involve movement of methanol by railroad tank cars to bulk terminals. When market demand has increased substantially, pipelines can be constructed between the synthesis plant and the bulk terminals.

The cost of transporting the methanol from the synthesis plant to the bulk terminal is covered in Table 7-4 and Figure 7-7. Movement by conventional train would cost around \$2.44/10⁶ BTU. Movement by pipeline would be around \$0.4/10⁶ BTU. A pipeline capacity of 100 KB/D represents about eight large plants supplying the system. If only one or two plants are served by a pipeline, the cost could be around \$0.8/10⁶ BTU.

The storage and distribution costs have been estimated at \$0.73/10⁶ BTU, based on the cost of storing and distributing petroleum products and adjusting the difference in heating value of the methanol compared to petroleum products. The study by Johnson(7-2) gives the storage cost of methanol, on a cents/gallon basis, as being the same as for distillates.

7.6.3 Total Delivered Cost to Customer

The total production, transportation and distribution cost for methanol, produced from either coal or biomass, is summarized in Figure 7-8. The coal resource based methanol is based on an Illinois coal (\$2.10/10⁶ BTU). The gasification and methanol synthesis plant could be located 500 miles from the mine with movement of the coal by unit train (\$0.69/10⁶ BTU) or the methanol synthesis plant could be located at the mine site, in which case the coal transportation cost would be on the order of \$0.05/10⁶ BTU (coal moved 10 miles by pneumatic line or truck). Another alternate would be to use Western coal, with the gasification and synthesis plant either at the mine site or located in the Midwest. The economics in Section 6.7.1 give the cost of using Western coal to produce methanol.

One possible method of producing methanol from biomass is to use sugarcane and generate a synthesis gas using the Purox process. Collection and transporting the material to the gasification and synthesis

FIGURE 7-8

METHANOL PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

plant could cost \$7.74/10⁶ BTU. The cost of manufacture of the syngas would be \$3.20/10⁶ BTU, while the methanol synthesis cost would be \$3.84/10⁶ BTU. The total cost of methanol from a 2000 T/D plant would be \$14.79/10⁶ BTU. Other methods of producing methanol from biomass are discussed in Section 6.7.2.

The distribution of methanol for non-highway transportation purposes is shown for two different scales of marketing. The initial marketing would most likely be in a few limited areas and transportation would be by railroad tank car. It is assumed the terminal would be located 500 miles from the synthesis plant. Once a large scale marketing system is established, the methanol could move by pipeline to a terminal. The assumed distance is 1000 miles. This could reduce the total cost of the methanol by as much as \$1/10⁶ BTU. Distribution and storage costs represent about 16-22% of the total cost of the delivered methanol.

7.7 Oxygenated Compound - Ethanol

7.7.1 Transportation Costs

One of the oxygenated compounds of potential interest as a transportation fuel is ethanol. If produced in very large quantities, the fuel could be moved by pipeline. The estimated relationship between pipeline cost and capacity for ethanol is shown in Figure 7-7. The cost of moving ethanol on a BTU/mile basis is slightly less than the cost of transporting methanol, since the heating value of ethanol is intermediate between methanol and petroleum liquids. As was the case with methanol, it will require about 10 1500 T/D ethanol plants to support a 100,000 B/D pipeline. For a biomass resource base, it is unlikely that this many plants would be in a given area and near a large pipeline.

If the ethanol were moved by rail, the transportation cost would be about 75% of that shown in Table 7-4 for methanol, or about \$0.90/10⁶ BTU per 1000 miles for a unit train and \$1.82/10⁶ BTU per 1000 miles for a conventional train, based on the basic rates given by Foster Associates. (7-7)

7.7.2 Storage and Distribution Costs

The distribution system for ethanol would probably be similar to that for methanol, except that the ethanol may be produced from grain or waste products. In that case, the distances involved would probably be shorter since it is expected that the production facilities will be smaller and more dispersed than a coal-based methanol system. The cost of transporting the ethanol from the synthesis plant to the bulk terminal is covered in Table 7-4 and Figure 7-7. If the ethanol moves by conventional rail car, the cost would be around \$1.80/10⁶ per 1000 miles. The distribution cost from the terminal to the user is estimated at \$0.55/10⁶ BTU, based on the cost for petroleum products adjusted for differences in heating value.

7.7.3 Total Delivered Cost to Customer

The total production, transportation, and distribution cost for ethanol produced from a corn resource base is shown in Figure 7-9.

FIGURE 7-9
ETHANOL PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

(1) Range reflects different cost of corn \$2.75/bushel to \$3.75/bushel

In the corn-based system, corn is purchased at an assumed price of \$3.75/bushel or \$13.50/MBTU. The fermentation step raises the total to \$21.20/10⁶ BTU.

The distribution system for ethanol for non-highway transportation is shown for two different scales of marketing. The initial marketing would most likely be in a few limited areas and the movement of the fuel would be by railroad tank car. It is assumed the production plant is located 1000 miles from the terminal. If a large scale operation were established where a pipeline system could be used, the distribution cost would drop to \$0.30-0.56/10⁶ BTU. However, with a biomass resource base, it is unlikely that a large scale system would develop. The reduction in cost would be \$1.26-1.52/10⁶ BTU or about a 10% reduction in cost.

7.8 Hydrogen

7.8.1 Transportation Costs

Hydrogen can be transported as a gas, as a liquid, or it could be distributed in metal hydride form. However, due to the weight of the metal hydride beds, this particular form is impractical and too costly to be considered for large volume transmission of hydrogen. Table 7-5 summarizes the literature data on the cost of transporting hydrogen by the various modes for both a gaseous and liquid form. The data from the various sources have been adjusted to 1980 dollars and put on a consistent unit basis.

7.8.1.1 Gas Pipeline

It is generally agreed that the most economical and convenient way to move large amounts of hydrogen in the future will be by gas pipeline.(7-15) There is some commercial experience on pipelining hydrogen. Air Products has an 8-inch line, 12 miles long, operating at a pressure of 200 psi in the Houston area.(7-14) A 130-mile pipeline (diameter of 6 to 12 inches) has been distributing hydrogen in Germany for nearly 30 years, at a pressure of about 150 psi.(7-15) Another hydrogen pipeline is 150 miles long and is located in Johannesburg.(7-14)

TABLE 7-5

SUMMARY OF H₂ TRANSPORTATION COSTS

Ref.	Cost - 1980 Dollars \$/10 ⁶ BTU per 1000 Miles	Mode	Comments
7-1	0.71	Gas Pipeline	36-inch diameter--2 billion SCF/day input
7-2	1.06	Gas Pipeline	1.55 billion SCF/day, 36-inch diameter pipeline, 15% capital recovery factor
7-20	1.49	Gas Pipeline	36-inch diameter pipeline, 0.87 x 10 ⁹ SCF/day
7-14	0.92	Gas Pipeline	36-inch diameter, 3.2 x 10 ⁹ SCF/D. Hydrogen fuel at \$7.6/10 ⁶ BTU
7-24	1.12	Gas Pipeline	36-inch diameter pipeline, 100 x 10 ¹² BTU/yr. Adjusted for fuel cost to \$7.6/10 ⁶ BTU
7-25	2.91	Gas Pipeline	12 x 10 ¹² BTU/yr. Assumes electric motor for compression at 2¢/kwhr.
7-26	0.69	Gas Pipeline	Assumes gas is at 440 psia at inlet
7-2	46.7	Liquid Pipeline	3-inch diameter pipeline, 550 x 10 ⁶ BTU/hr
7-13	40.15	Liquid Pipeline	Based on 1000 miles. For 50 miles, cost would be only \$15.95/10 ⁶ BTU per 1000 miles
7-13	2.91	Railroad	9165 kg load (34 x 10 ³ gals)
7-15	8.40	Railroad	Rate for 100 miles based on a 500 mile trip and freight rate of 1¢ per ton miles
7-25	5.82	Railroad	Rate for 50 to 200 mile range. Specific basis in reference
7-2	1.28	Barge	1800 x 10 ⁶ BTU/hr, 1.1 x 10 ⁶ gal barge
7-15	1.33	Barge	

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/10⁶ BTU per 1000 Miles</u>	<u>Mode</u>	<u>Comments</u>
7-2	6.34	Truck	62 x 10 ⁶ BTU/hr, 13 x 10 ³ gal trailer
7-13	6.44	Truck	11,442 gal trailer
7-15	7.00	Truck	--
7-25	6.46-8.72	Truck	13,000 gal trailer. Range depends on cost, inflation (base year not given)

There have been several studies on converting the existing natural gas system to carry hydrogen.(7-14,15) A study by Gregory(7-14) showed that an unmodified natural gas line would be severely reduced in capacity, to 26% of its original value, if hydrogen were to be substituted without modification, as shown in Table 7-6 below.

TABLE 7-6

RELATIVE CAPACITY OF TRANSMISSION LINE
ON HYDROGEN AND NATURAL GAS AT 750 PSIA

<u>Gas</u>	<u>Compressor Capacity</u>	<u>Compressor Horsepower</u>	<u>Energy Delivery Rate</u>
Natural	1.0	1.0	1.0
Hydrogen	1.0	0.1	0.26
	2.1	1.0	0.56
	3.8	5.5	1.0

Source: Ref. 7-14.

This assumes that the compressor efficiency would be unchanged, which is valid only for reciprocating compressors. As shown above, modifications in both the compressor and the engines must be made to recover the original capacity of the line. Turbocompressors would be replaced with custom-designed equipment intended for hydrogen service.

Several in-depth studies have also been made on the cost of a dedicated gaseous hydrogen pipeline.(7-14,24,25,26) The Institute of Gas Technology (IGT) has made a very complete study on the optimum overall transmission cost for a 1000-mile gaseous hydrogen pipeline.(7-24,7-14) The study by IGT was based on radial turbocompressors designed for hydrogen service, with gas turbine drives, using hydrogen for fuel. Pipeline sizes from 24 to 48 inches were investigated. Operating pressure levels of 750 to 2000 psi were evaluated. The study by IGT considered H₂ costs \$2,3 and 4/10⁶ BTU, and used a capital recovery factor of 13%. The results presented by IGT were extrapolated to a hydrogen fuel cost of \$10/10⁶ BTU and the investment data adjusted to 1980 dollars and a 15% capital recovery factor. The original study by IGT optimized the capacity of the system with fuel costs, so an extrapolation to a \$10/10⁶ BTU fuel cost represents a large deviation from the original study. Thus, the cost of transmitting hydrogen as a function of capacity, shown in Figure 7-10, is at best an estimate of the cost to transmit hydrogen under these conditions. The other data on gaseous pipeline costs from Table 7-5 are plotted in Figure 7-10 for comparison. There is general agreement, with two studies showing higher cost. Increasing operating pressure to 2000 psig would reduce the cost, but this is quite an extension from the 150-200 psia operating pressure of current hydrogen pipeline systems.

FIGURE 7-10

H₂ GAS TRANSMISSION COST

The cost of transmitting natural gas is shown in Figure 7-10 for comparison. The cost of transmitting hydrogen is estimated to cost 2-3 times more than today's natural cost transmission costs. (7-24) For this study the data from Reference 7-24 will be used.

It is interesting to consider the number of hydrogen plants required to support a large pipeline. About eight plants would be required to supply 100×10^{12} BTU/year hydrogen compared to about a single 250×10^6 SCF/D SNG plant. A single large hydrogen plant (100×10^6 SCF/D) would supply around 12×10^{12} BTU, which according to Reference 7-25, would involve a transportation cost of \$2.91/ 10^6 BTU per 1000 miles.

In the economics of transporting gaseous hydrogen, it is assumed that the hydrogen gas is at the initial pipeline pressure. Thus, it is necessary to insure that the initial cost of compressing the gas to pipeline pressure is included. The gaseous hydrogen produced from coal in Reference 2-45 is at a pressure of 450 psig. Therefore, a cost for compressing this from 450 to pipeline pressure of 750 psia must be included in the total cost analysis. A study by IGT (7-25) contains some information on the cost to compress hydrogen. Adjusting to 1980 dollars and to an electricity cost of 3¢/kwhr, it is estimated that the compression cost would be around \$0.5/ 10^6 BTU.

7.8.1.2 Liquid Hydrogen

Over one billion gallons of liquid hydrogen has been produced and distributed in support of the space program. (7-2) This liquid hydrogen has been moved by tank truck and rail. Transport of liquid hydrogen is more difficult and therefore more costly than transport of petroleum fuels because of the necessity of cryogenic facilities.

It is technically possible to distribute liquid hydrogen through an extremely well insulated cryogenic pipeline. However, as shown in Table 7-5, the costs are very high, in the range of \$40-47/ 10^6 BTU per 1000 miles. Such pipelines would be economical for only very short distances and for very high hydrogen flow rates. For example, in aircraft application, it may be necessary to move liquid hydrogen underground a mile or so from the liquefaction plant to the aircraft fueling station.

The cost to transport liquid hydrogen by railroad, barge and by truck are shown in Table 7-5. The rail cost reported in Reference 7-13 appears low and the rate given in Reference 7-15 will be used in this study for rail movement of liquid hydrogen. The cost of barge shipment is comparable to the cost of a gaseous hydrogen pipeline. The cost of truck transport is in the same range as rail--the \$7-8/ 10^6 BTU per 1000 mile range. Reference 7-25 gives additional details on the basis for the cost of both rail and truck transportation and how they vary with trip distance.

7.8.1.3 Literature Studies on Systems Optimization

Several studies have dealt with the most economical method to transmit hydrogen. Johnson (7-27) investigated the supply of liquid hydrogen

for air transportation. He concluded that gas pipelining was cheaper than barging and that the liquefier should be located at the airport. Sindt(7-13) looked at seven different systems for supplying liquid hydrogen with the hydrogen being produced from water in an electrolyzer. He concluded that the most practical means of supplying liquid hydrogen to users within about 50-75 miles of the power plant is probably by truck. If the use is at a single installation, gas pipeline is probably the best choice. If the transmission distance is long, around 1000 miles, he concluded railroad delivery is attractive. However, the rail rates used in his study appear to be very low. If the use is by a single consumer, the gas pipeline was the most efficient and practical since the boil-off gas from and liquid transfer could be reliquefied. Dickson, et al.(7-15) concluded that the most economical and convenient way to distribute large quantities of hydrogen would be by gas pipeline.

7.8.2 Liquefaction Costs

For hydrogen to be used as a transportation fuel, it will be necessary to convert the gaseous hydrogen to a liquid form. The major steps in liquefaction of hydrogen are purification, refrigeration, and conversion/liquefaction. Table 7-7 summarizes the various cost estimates from the literature, after adjusting to a consistent basis. The estimates are for a 250 ton/day size plant. The largest liquid hydrogen plant which has been built and operated had a capacity of 60 tons/day, but this was not strictly a single train plant.(7-28) Accepting a considerable amount of paralleling of equipment, it should be possible to build a 250-TPD plant with a single cold box. Thus, a 2500 TPD liquefaction complex would consist of ten 250 TPD modules.(7-28)

The various cost estimates are fairly consistent, except the costs based on data in Reference 7-25. For this study, the cost given by Union Carbide(7-28) will be used since this is the most recent, detailed study on the economics of hydrogen liquefaction and sufficient information is provided to allow adjustments to be made.

The power requirements for producing 97% para hydrogen as a saturated liquid, starting with gaseous hydrogen at 200 psig was reported at 5.67 kwh/pound.(7-28) This value was adjusted to reflect a feed hydrogen pressure of 700 psig, using a correlation presented in the Union Carbide report. The electrical requirements at 700 psig, including that required for the ortho-para conversion, would be 4.95 kwh/pound. The 1974 investments were adjusted to a 1980 dollar basis using a chemical equipment index of 1.18 to adjust to 1975 cost and an inflation factor of 7% per year from 1975 to 1980. Operating cost and maintenance was also adjusted to 1980 costs using the same factors. A 20% capital recovery factor was assumed, and an electricity cost of 3¢/kwh was used. This gives a cost of liquefaction of \$4.40/10⁶ BTU. The effect of different assumptions on capital recovery rates is illustrated below:

<u>Capital Recovery</u>	<u>Cost of Liquefaction--\$/10⁶ BTU</u>
20% CRF	4.40
12% DCF	4.80
Utility financing	4.10

TABLE 7-7SUMMARY OF HYDROGEN LIQUEFACTION COST

<u>Ref.</u>	<u>Cost - 1980 \$</u> <u>\$/106 BTU</u>	<u>Comments</u>
7-15	4.17	Based on a 1973 study by Linde; adjusted to a 20% capital recovery factor and an electricity cost of 3¢/kwh. 250-ton/day plant
	3.94	Based on a 1968 study by Air Products; adjusted to the same basis as used above
7-28	4.40	Based on a 1975 study by Union Carbide
7-12	3.86	
7-25	8.62	Cost for both 250 and 100 T/D size plants
7-19	6.37	100 T/D size plant
	3.63	Large size plant, using electricity from nuclear power plant

7.8.3 Distribution Costs for Hydrogen at Major Airport Facilities

Studies have been made by Lockheed(7-16) and by Boeing Airplane Company(7-17) on the cost of distributing liquid hydrogen to a hydrogen-fueled aircraft. In the Lockheed study, the San Francisco International Airport was used as a basis for the analysis and a complete facility was conceptually designed. The facility includes the liquefaction plant, LH₂ storage, and LH₂ fuel handling system. Also, the requirements for ground support and maintenance for the LH₂-fueled aircraft were analyzed. Based on the reported investment cost, an estimate of the liquefaction cost, storage cost, and distribution cost can be obtained. The investment for a 250 T/D liquefaction plant (ex interest during construction, start-up cost and working capital) was $\$76.7 \times 10^6$ (1980 dollars) in the Lockheed study, compared to $\$81.3 \times 10^6$ (1980 dollars) for the same size plant reported by Union Carbide in Reference 7-28. The storage cost of around $\$5.60/\text{gal}$ is considerably higher than reported in other references.(7-2,3) The storage cost and distribution cost on a $\$/10^6$ BTU basis is 0.27 and 0.07, respectively. However, in comparing this to the Boeing study, it will be shown that these values appear low.

Boeing evaluated the cost of installing a liquid-hydrogen (LH₂) supply system at the Chicago O'Hare International Airport.(7-17) The study looked at the cost of installing a hydrogen liquefaction and storage system, as well as the fuel distribution system. The study assumed a dual fueling system (LH₂ or JP fuel) but also considered only a LH₂ system. Table 7-8 shows the comparison between the two studies and attempts to put them on a common basis. All costs have been adjusted to a 1980 dollar basis. As can be seen, there is a large difference between the two studies on basis and on economics. The liquefaction investment was provided by Air Products and is approximately $\$100 \times 10^6$ for a 250 T/D size plane. This is a rough estimate since sufficient data are not reported to make an exact comparison. Part of the difference could be due to differences in construction costs in Chicago, compared to San Francisco. Also, Boeing has included storage (265,000 ft³) for gaseous hydrogen in an underground accumulator that will increase the cost. In addition, Dickson(7-15) has reported that the investment for liquefaction plants quoted by Linde (Union Carbide) are usually lower than that quoted by Air Products, but the final cost of liquefaction tends to converge because Air Products assumes a slightly lower electricity consumption rate than Linde.(7-15)

The storage cost, reported by Boeing on a dollar per gallon basis, is also greater than the Lockheed study. The major difference, however, is in the distribution cost, with Boeing reporting a distribution cost over three times greater than Lockheed. For this study, the values reported by Boeing will be used.

7.8.4 Total Delivered Cost to Customer

The total production, transportation, and distribution costs for liquid hydrogen produced from coal as the resource base and with hydrogen produced from electricity, with either coal or uranium as the base resource, is shown in Figure 7-11.

TABLE 7-8

COMPARISON OF TWO STUDIES ON COST TO
DISTRIBUTE LIQUID HYDROGEN AT MAJOR AIRPORTS

Ref.	<u>7-17</u>		<u>7-16</u>
	CH ₂		CH ₂
Hydrogen Delivery State	Dual	Separate	Separate
Fueling Concept			
LH ₂ Capacity - tons/day	800	800	1000
Annual Average Fuel Required - tons/day	600	600	636
Storage Capacity - tons	1600	1600	1480
<u>Capital Required - \$10⁶ (1980 \$)</u>			
Liquefaction & Pumping - \$10 ⁶ /T/D capacity(1)	0.53	0.53	0.40
Storage System(1) - \$10 ⁶ /T/D(2)	0.077	0.077	0.044
- \$/gal	8.54	8.54	5.6
- \$/10 ⁶ BTU handled(3) (Avg)	0.50	0.50	0.27
Distribution System			
- Hydrogen System Only - \$10 ⁶ /T/D(2)	0.24	0.21	0.07
- Airport and Ground - \$10 ⁶ /T/D	<u>0.08</u>	<u>0.046</u>	<u>--</u>
- Total - \$10 ⁶ /T/D(2)	0.32	0.27	0.07
- \$/10 ⁶ BTU(3)	2.02	1.65	0.46

(1) Includes interest during construction, start-up cost and working capital.
Based on LH₂ capacity shown.

(2) Based on annual average fuel required.

(3) Based on LHV for hydrogen; 20% capital recovery*factor and 4% for operating and maintenance cost.

FIGURE 7-11

HYDROGEN PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

(1) Based on coal resource base.

As discussed in Section 6.8.1, the cost to produce hydrogen from coal via the gasification route is \$6.2-7.9/10⁶ BTU using K-T coal gasification technology. This cost is based on using Eastern coal, with a coal transportation cost of \$0.04-0.48/10⁶ BTU, depending on the distance of the plant from the coal mine. Other options are possible, such as mine mouth location of the hydrogen production facilities or the use of Western coal (mine mouth or midwest location).

Hydrogen can also be produced by electrolysis of water, as described in Section 6.8.2. The electricity can be generated from coal or nuclear energy or any of the other advanced technologies being considered. The projected cost is higher, at around \$13/10⁶ BTU. These costs include compressing the product to 450 psig. The cost to increase the pressure to the assumed pipeline pressure of 750 psia is estimated to be \$0.5/10⁶ BTU.

It is assumed that the hydrogen will be transported as a gas in a 1000 mile long pipeline. If the capacity of the line is about 100 x 10¹² BTU/year (about eight plants of 880 x 10⁶ SCF/D capacity each), the transportation cost would be around \$1.15/10⁶ BTU. If the line was supplied by a single large plant (100 x 10⁶ SCF/D), the transportation cost would increase to around \$2.20/10⁶ BTU. For the airport requirements described in Table 7-8, two 100 x 10⁶ SCF/D size plants would be required, which would mean a pipeline cost of around \$1.70/10⁶ BTU.

It is assumed that to be usable as a transportation fuel, it will be necessary to liquefy the hydrogen for storage on board a vehicle of some type. This will add \$4.40/10⁶ BTU to the cost of the hydrogen. Storage and distribution cost for an aircraft type application would add around \$2.15/10⁶ BTU, bringing the total delivered cost to about \$18-19/10⁶ BTU for hydrogen from coal. Hydrogen from electrolysis of water would be even more expensive.

In the case of liquid hydrogen, non-production costs are around half of the total cost of the delivered product to the customer. This is considerably greater than for coal or shale-derived liquids.

7.9 Methane

7.9.1 Transportation Costs

Methane would be transported to a liquefaction plant via pipeline. Methane could also be imported as LNG by tanker, but the aim of this study is to concentrate on domestic supplies. The cost of transmitting gases by pipeline will depend on the distance, volume moved, pressure of the pipeline system, terrain to be crossed, acceptable rate of return, etc. Gas pipelines are highly capital intensive, with about 90% of the costs fixed and 10% operating and maintenance cost, partially constant and partially variable depending on throughput. (7-22) The cost of pipeline transmission is very sensitive to the load factor. Table 7-9 summarizes the literature data on gas transmission cost for a gas with a heating value of 1000 BTU/SCF. The literature data were adjusted to a 1980 dollar basis.

TABLE 7-9SUMMARY OF METHANE TRANSMISSION COST

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/10⁶ BTU per 1000 Miles</u>	<u>Comments</u>
7-1	0.44	36-inch diameter line, with 870 million SCF/day input and 816 million SCF/day output, operating 360 days/year
7-2	1.29	36-inch diameter line with 500 million SCF/day throughput and 20% capital recovery factor
7-3	0.95	Same as 7-2 except capital recovery factor is 15%
7-9	0.56 0.37	For 500 million SCF/day. For 1 billion SCF/D
7-22	0.37	30-inch diameter line at 800 psig and 95% capacity
7-19	0.37	

A study by Nagarvala, et al. (7-20) derived the cost of an inter-regional pipeline transmission cost for gas pipelines--as a function of pipeline capacity. Figure 7-12 shows how the cost of transmitting methane by pipeline varies with throughput. A 15% capital recovery factor is assumed in this figure. The other literature data points are in general agreement with the curve calculated from Reference 7-20, except for Reference 7-3.

7.9.2 Liquefaction Costs

To use methane as a transportation fuel for any mode where the fuel must be carried on board the vehicle, the methane will need to be liquified. Table 7-10 summarizes the cost of liquefying methane, based on literature data, and adjusted to a common basis.

TABLE 7-10

METHANE LIQUEFACTION COST

<u>Ref.</u>	<u>Cost--1980 Dollars</u>	
	<u>\$/10⁶ BTU</u>	<u>Comments</u>
7-29	2.03	250 x 10 ⁶ SCF/D plant
7-12	1.83	--
7-19	3.02	10 x 10 ⁶ SCF/D plant

The basic cost of liquefaction used in this study is based on the article by DiNapoli. (7-29) The direct capital cost items include the liquefaction and utilities section, but exclude any storage facilities. Based on the data from DiNapoli, (7-29) the indirect costs were taken at 41% of the direct cost and a 15% contingency was used. Owners' costs of 35% of the total erected costs were also included. Other bases used in arriving at the \$1.91/10⁶ BTU were:

- 20% capital recovery factor (basis for this study).
- Operation and maintenance costs at 6% of initial investment per Ref. 7-29.
- Fuel requirement of 13% of the feed volume and a feed cost of \$5.15/10⁶ BTU. (7-29)
- 320 days per year operation and an 86% overall production efficiency. (7-29)

7.9.3 Storage and Distribution Costs

If methane is used as a transportation fuel, it would need to be liquefied and move as a liquid. If used as an aircraft fuel, it is assumed that the methane would be moved to the airport as a gas and then

FIGURE 7-12

COST OF TRANSPORTING METHANE BY PIPELINE

liquefied at the airport. In this case, the added cost of LNG storage and loading facilities would add about \$0.15/10⁶ BTU to the liquefaction cost, based on data in Reference 7-29. As a first approximation, the distribution costs within the airport will be assumed at 50% of the cost of the storage and distribution costs for liquid hydrogen or \$1.10/10⁶ BTU. Information in Reference 7-33 shows this for the study Rand made for the Air Force, comparing liquid hydrogen and liquid methane.

If liquid methane is moved by tank truck to the customer, the distribution costs would be as follows:

	<u>\$/10⁶ BTU (1980 \$)</u>
LNG Storage and Loading Cost	0.15
Marketing Cost	0.13
Tank Truck to Customer Over 250 Mile Radius	0.84
	<hr/>
	1.12

The tank truck delivery cost is based on Reference 7-19, adjusted to a 1980 dollar cost basis.

7.9.4 Total Delivered Cost to Customer

The total production, transportation, and distribution cost for liquid methane produced from coal as the resource base and from sewage algae is shown in Figure 7-13.

As discussed in Section 6.11.1, the cost to produce methane from coal via gasification is \$6.20-8.80/10⁶. This cost is based on using Eastern coal at \$21/ton, ex. any coal transportation cost of \$0.08-0.88/10⁶ BTU, depending on the distance of the gasification plant from the mine. The \$0.08/10⁶ BTU represents a SNG plant near the mine (10 miles), while the higher number represents moving coal by unit train 500 miles. Western coal could also be used with slightly different economics.

Methane can also be produced from biomass. Production costs from anerobic fermentation or an advanced pyrolysis process is shown on the right-hand side of Figure 7-13. The \$4.60/10⁶ feedstock costs include a transportation cost. The total cost of methane from this route is more expensive than from the coal resource base.

It is assumed that the SNG will move 1000 miles by pipeline at a cost of \$0.4-0.6/10⁶ BTU, depending on the throughput of the transportation system. Liquefaction will add \$2/10⁶ BTU to the cost of the fuel. The distribution cost for liquid methane for an aircraft type application is estimated to be an additional \$1.10/10⁶ BTU, bringing the total delivered

FIGURE 7-13

**METHANE PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM**

(1) Based on a coal resource.

cost to the customer to the \$10-12.50/10⁶ BTU range. Distribution, liquefaction and storage costs represent around a third of the total cost, with the production of the SNG from coal representing around two-thirds of the total cost.

7.10 Ammonia

7.10.1 Transportation Costs

Production of ammonia for fertilizer has reached a scale of distribution in which large interstate pipelines are now operating in addition to the extensive barge, rail, and truck systems that have been built to achieve economical distribution.(7-4) A summary of the costs associated with several methods of transporting liquid ammonia is given in Table 7-11. The most economical way to move large volumes of ammonia would be by pipeline. The estimated relationship between pipeline cost and capacity for ammonia is shown in Figure 7-14, based on the curve shown in Figure 7-4, adjusted for the net heating value difference between petroleum distillate and ammonia. As would be the case for methanol, the location and number of plants near the pipeline would determine the size and capacity of the line. For example, it would take seven (7) 2000 T/D ammonia plants to feed a pipeline with a 100,000 B/D capacity.

The next most economical mode of transportation for ammonia would appear to be by barge, if navigable waterways are available. The barge rate for ammonia is based on Reference 7-7, based on \$0.85/ton mile for coal. Since a different type of barge would be required, the rate for ammonia would probably be greater than the \$1.23/10⁶ BTU per 1000 miles shown.

The ammonia could also be transported by rail. Rates for a unit train and a conventional train are shown in Table 7-11, based on rail rates for coal, adjusted to 1980 dollars and to reflect the difference in weight and heating value between coal and ammonia.

7.10.2 Storage and Distribution Costs

The cost of storing ammonia will depend on whether the ammonia is stored with full refrigeration, partial or if stored under full pressure. Reference 7-2 reports an ammonia storage cost that is 2.85 times more expensive than the basic cost for distillates and fuel oil. It is assumed that this cost is for full refrigeration, but the cost of refrigeration would have to be added to this value. This cost would depend on evaporation loss and geographical location. Storage under full pressure conditions could cost up to 6.3 times more than full refrigeration costs. The estimated storage and distribution cost is as shown on page 7-43.

If the storage was under full pressure conditions, the total cost would increase to around \$5/10⁶ BTU.

TABLE 7-11SUMMARY OF AMMONIA TRANSPORTATION COST

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/10⁶ BTU per 1000 Miles</u>	<u>Mode</u>	<u>Comments</u>
7-2	1.21	Pipeline	36-inch diameter line, about 390,000 B/D; 20% capital recovery factor; 100% utilization
7-3	0.93	Pipeline	Same as Ref. 7-2 except used a 15% capital recovery factor
7-7	2.17	Unit Train	Based on 1.5¢/ton-mile in 1975 dollars for 1000 miles
7-7	4.35	Conventional Train	Based on 3¢/ton-mile
7-7	1.23	Barge	Based on \$0.85/ton-mile.

FIGURE 7-14

COST OF MOVING LIQUID AMMONIA BY PIPELINE
(BASED ON FIGURE 7-4, ADJUSTED FOR HEATING VALUE)

\$/10⁶ BTU (1980 Dollars)

Terminal Operating Cost	0.29
Marketing Cost (assumed same as for petroleum on a dollar/barrel basis)	0.60
Movement to Customer by Conventional Train (500 miles)	2.18
Capital Recovery on Storage	<u>0.30</u>
	3.37

7.10.3 Total Delivered Cost to Customer

The total production, transportation and distribution cost for ammonia produced from coal or biomass is shown in Figure 7-15.

As discussed in Section 6.9.1, the cost to produce ammonia from coal gasification is around \$12-13/10⁶ BTU. This cost is based on using Eastern coal at \$21/ton, with a coal transportation cost of \$0.07-0.76/10⁶ BTU, depending on the distance of the ammonia synthesis plant from the mine. The \$0.07/10⁶ BTU represents a location near the mine (10 miles), while the higher cost represents moving coal by unit train 500 miles.

Ammonia could also be produced by sugarcane via the Purox gasification route, with the cost being higher, around \$18/ton.

It is assumed the ammonia would be moved by pipeline 1000 miles at a cost of \$0.4-0.8/10⁶ BTU, the range representing a pipeline capacity of 600 KB/D to 80 KB/D. Terminal storage and distribution to the customer would add about \$3.40 to the cost, bringing the total cost to around \$16-17/10⁶ BTU for a coal-based system and \$22/10⁶ BTU for a biomass-(sugarcane) based system.

7.11 More Exotic Fuels

Literature information on the transportation and storage cost of the more exotic fuels, acetylene, hydrazine, and methylamine was not available. A rough approximation has been made for each of the fuels for the preliminary screening.

7.11.1 Acetylene7.11.1.1 Transportation Costs

The cost of shipping acetylene adds considerably to its costs because it cannot be transported in liquid form or as a free gas under high pressure. The normal means of transportation is in special cylinders,

FIGURE 7-15

**AMMONIA PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM**

(1) Based on coal resource.

dissolved in acetone at about 250 psi pressure. However, this is a very inefficient means of transportation since the dissolved acetylene in the acetone represents less than 10% of the total shipping weight. Considering that the empty cylinder must be returned, the net efficiency of shipping is less than 5% of the gross weight.(7-30) Assuming a rail freight rate of 4.2¢/ton-mile (1980 dollars), the freight cost would be greater than \$20/10⁶ BTU per 1000 miles. The actual rate is likely to be more than this, since the base freight rate used was for coal. The rate for acetylene cylinders is set by the ICC and depends on many factors. As a rough approximation, the above rate will be used.

According to Kirk-Othmer, the cheapest form of transporting acetylene by common carrier is by shipping the calcium carbide in metal drums and then generating the acetylene onsite from the reaction between calcium carbide and water. One reference(7-30) states that calcium carbide gives off acetylene equal to about 31% of its weight. Assuming a rail freight rate of 4.2¢/ton-mile in 1980 dollars, the freight rate for the calcium carbide and container would be around \$3.60/10⁶ BTU of acetylene per 1000 miles. This is probably the lowest the transportation cost will be, since the actual freight rate for calcium carbide in drums is probably higher than the assumed rate.

7.11.1.2 Storage and Distribution Costs

Literature data were not available on the storage or distribution costs for calcium carbide. For the preliminary screening, some rough approximations will be made to get an order-of-magnitude estimate for storage cost. It is assumed that the transportation will be by rail freight from the point of manufacture to a warehouse storage terminal at the rate shown above. The calcium carbide would be stored in metal drums, holding 100 or 220 pounds per can. The cost of the terminal for the solids could run up to \$1/10⁶ BTU of acetylene, depending on turnover rate of the inventory, investment cost of the terminal, terminal space utilization, etc.

7.11.1.3 Total Delivered Cost to the User

The production, transportation and distribution cost for acetylene as produced from calcium carbide and water is shown in Figure 7-16. The calcium carbide is produced from Eastern coal at a total cost of around \$14/10⁶ BTU. It is assumed that the calcium carbide is shipped by rail to a warehouse located 1000 miles away from the production facilities. Warehouse handling costs are estimated to be at least \$1/10⁶ BTU and probably greater. The total delivered cost to the user will thus be in excess of \$19/10⁶ BTU.

7.11.2 Hydrazine

Hydrazine is dangerous to transport in the undiluted state and is normally transported as a hydrate, N₂H₂·H₂O, or fuming liquid that can be dissolved in water for additional safety in handling.(7-31) Assuming a rail freight cost of 4.2¢/ton-mile (1980 dollars) the freight cost would

FIGURE 7-16

ACETYLENE PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

be a minimum of \$3.25/10⁶ BTU per 1000 miles, and probably much higher than this. In addition, storage and distribution costs would be added to this. If hydrazine is selected as a fuel for further study, it will be necessary to contact companies handling the material to obtain a cost of distribution and shipping.

7.11.3 Methylamine

Methylamine is normally sold as an aqueous solution containing 25-40% amine by weight or as an anhydrous liquid. The aqueous solution can be shipped in iron drums or tank cars and the anhydrous amine in steel cylinders or ammonia-type tank cars. Assuming a freight rate of 4.2¢/ton-mile (1980 dollars), the transportation cost for methylamine would be \$1.63/10⁶ BTU per 1000 miles, assuming anhydrous material, which probably represents a minimum value. Storage and distribution costs would be additive to the above value.

The distribution, production and transportation costs are summarized in Figure 7-17. These estimates are very rough, due to the lack of detailed information on the cost of production of hydrazine. It would appear that the major cost of producing hydrazine is associated with manufacturing, not the transportation or distribution.

7.12 Electricity

7.12.1 Transmission

Electricity is transmitted through power lines operating at various voltages typically ranging from 115 to 766 KV. The highest voltage lines are designed to handle the largest power loads and the longest transmission distances. Transmission costs refer to moving of electric power from the generating station to a major load center. It will also be necessary to consider the cost of distributing the electricity to the consumer. Table 7-12 summarizes the literature data on electric transmission costs. All data have been adjusted to a 1980 dollar basis. Transmission costs vary considerably depending on capacity, distance, and terrain. Even lines with the same nominal voltage may have widely different costs.(7-6) The following illustrates how transmission costs may vary with capacity.

<u>Capacity - KV</u>	Cost--1980 Dollars	
	\$ / 10 ⁶ BTU per 1000 miles--	
	<u>Overhead Lines</u>	
	<u>Ref. 7-6</u>	<u>Ref. 7-20</u>
138	12.31	5.79
230	6.15	4.32
345	3.69	3.44
500	1.65	2.71
765	1.65	1.88

The data in Reference 7-20 is reported for optimum line loading and are therefore expected to be lower than actual cost since few systems operate optimally at all times.

FIGURE 7-17

HYDRAZINE PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

TABLE 7-12SUMMARY OF ELECTRICAL TRANSMISSION COST

<u>Ref.</u>	<u>Cost - 1980 Dollars</u> <u>\$/10⁶ BTU per 1000 Miles</u>	<u>Comments</u>
7-1	4.59	500 KV AC transmission line, 1000 MW/day input, 85% load factor
7-2	4.70	4000 MVA superconducting line; 20% capital recovery factor
7-2	1.86-2.79	Above ground 750 KV, 2500 MVA line
7-6	1.65	For 765 KV line. Cost increase to \$12.31/10 ⁶ BTU per 1000 miles for a 138 KV capacity
7-20	1.88	For 765 KV line
7-32	\$3.69/10 ⁶ BTU	For large consumers based on escalation of 1972 average cost. \$3.03/10 ⁶ for transmission and \$0.66/10 ⁶ BTU for distribution. Transmission distance not specified

7.12.2 Distribution Cost

The distribution cost reported in Reference 7-27 of \$3,69/10⁶ BTU represents an escalation of the 1972 U. S. average cost of transmission and distribution for large light and power users.

7.12.3 Total Delivered Cost

Figure 7-18 summarizes the total delivered cost of electrical energy to a large industrial user, based on generating electricity from coal at \$21/ton. The transmission cost is for 1000 miles, and the transmission and distribution cost represents about a third of the total delivered cost.

FIGURE 7-18ELECTRICITY PRODUCTION,
TRANSMISSION AND DISTRIBUTION

REFERENCES ON COST OF TRANSMISSION
AND DISTRIBUTION OF ALTERNATE ENERGY SOURCES

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16. Abstracts <p>A planning study has been made for DOE on alternate fuels for non-highway transportation (aircraft, rail, marine and pipeline). The purpose of the study was to provide DOE with a recommendation of what alternate fuels may be of interest to non-highway transportation users from now through 2025 and to recommend R&D needed to allow non-petroleum derived fuels to be used in non-highway transportation.</p> <p>In the near term (present 1985), there is unlikely to be any major change in the fuels used in any of the four modes of transportation except that the average quality of the marine fuel is likely to get worse. In the mid-term period (1985-2000), there will be a transition to non-petroleum fuels, based primarily on shale oil derived liquids assuming a shale oil industry is started during this time.</p> <p>(over)</p>																						
17. Key Words and Document Analysis. 17a. Descriptors <table border="0"> <tr> <td>Alternate Fuels</td> <td>Shale Oil Liquids</td> </tr> <tr> <td>Marine</td> <td>Methanol</td> </tr> <tr> <td>Aircraft</td> <td>Hydrogen</td> </tr> <tr> <td>Pipeline</td> <td>Ammonia</td> </tr> <tr> <td>Railroad</td> <td>Ethanol</td> </tr> <tr> <td>Economics</td> <td>Methane</td> </tr> <tr> <td>Distribution Cost</td> <td>Transportation Cost</td> </tr> <tr> <td>Fuel Manufacture</td> <td>Storage Cost</td> </tr> <tr> <td>Coal Liquids</td> <td></td> </tr> </table>					Alternate Fuels	Shale Oil Liquids	Marine	Methanol	Aircraft	Hydrogen	Pipeline	Ammonia	Railroad	Ethanol	Economics	Methane	Distribution Cost	Transportation Cost	Fuel Manufacture	Storage Cost	Coal Liquids	
Alternate Fuels	Shale Oil Liquids																					
Marine	Methanol																					
Aircraft	Hydrogen																					
Pipeline	Ammonia																					
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16. Abstracts (cont.)

The future outlook for possible prime movers and potential fuel sources for the long term (2000+) is as follows. In the marine area, steam engines burning coal or diesel engines with unrefined shale oil or coal slurries are the prime candidates. With the aircraft gas turbine, either synthetic liquids from shale or coal would appear to be the most desirable fuels. Railroads will probably remain with the diesel/electric prime mover using shale oil as a source of distillate. Pipelines will probably use electric motors as the major type of prime mover.

This Appendix covers the economics of producing, transporting and distributing the various fuels.

8. ENVIRONMENTAL IMPACT IN PRODUCTION

E. M. Magee

One of the factors considered in the preliminary screening of the various alternate fuels was the environmental impact during production. Much has been written concerning the effluents to the environment on converting coal or shale to liquids, SNG, etc. (References 8-1 through 8-7). Tabulations have been made, often to three significant figures, of emissions of SO_2 , NO_x , etc. to the atmosphere; phenols, suspended solids, etc. to water; and solids to land. Quantities of effluents from processes of different developers have been compared even though commercial plants have never been built. Previous studies have pointed out (Reference 8-2, page 3) that the pollutants from a process are a function of a number of variables and thus no hard number can be assigned to any process. Four of the major factors determining qualities of effluents are plant design, location, raw material and the methods used to provide utilities.

Perhaps the plant design has the most effect on the effluents. For example, the SO_2 effluent can be changed dramatically when generating steam by firing clean fuel gas rather than raw coal. Effluents in water can be reduced to zero by ponding. Even without ponding, pollutants in effluent water can be changed by changing the degree of treatment. Water effluent is also greatly affected by the type of cooling (air vs. cooling water).

The location of the plant and the source/quality of utility supplies has a great influence on either the effluents or the treatment required for the same effluent. For example, the total dissolved solids in the raw water supply has a direct effect on the quantity of pollutants in cooling tower blow down. Ambient temperature and annual rainfall affect the quality of emissions. In addition, local environment regulations also can have a major bearing on the amount of emissions.

The raw material has a large effect on pollutants in effluents (or, again, on the treatment required). For example, the sulfur and ash content of coal will affect effluents. Again, any adverse effects from raw materials can usually be obviated by proper design.

Publication of a table of emissions from two processes producing similar products can be misleading. One normally does not take the time to examine the bases for the numbers in a table and will usually assume that one process is inherently "dirtier" than another. They fail to realize that the quantities of emissions are, in large part, due to the original assumptions made in the design and that the "dirty" process can usually be made as clean or cleaner than another by changing the assumptions. One example, picked at random, will emphasize this point. In Reference 8-7 (page 24) various "environmental burdens" for different energy "modules" are listed. For solvent refining of coal the SO_2 emissions are given as $0.003 \text{ lb}/10^6 \text{ BTU}$ whereas, for refining of domestic crude, the SO_2 level was listed as $0.135 \text{ lb}/10^6 \text{ BTU}$ or 45 times as much as solvent refining of coal. Since coal contains more sulfur per MBTU than crude and since the thermal efficiency of a refinery is higher than solvent refining of coal, it is obvious that a different level of sulfur removal was assumed for the coal case. Similar reasoning can be applied to the water emissions for these two cases.

The conclusion from this is that a fuel process should not be chosen on the basis of the effluents resulting from an arbitrary design. The only logical way to compare two processes making essentially the same products would be to prepare specifications for all effluents, choose a specific location and raw material and prepare designs for both with the same assumptions. The cost of products from the two might then be used as a basis for comparison. Unfortunately, most processes are in such rudimentary state of development that even this lengthy and costly procedure might not give the correct answer.

Despite the above qualification, Table 8-1 is given as an order of magnitude guide to the emissions from the production of various fuels. Table 8-2 gives a breakdown of the air pollutants. Values given in the tables are, for the most part, calculated using values given in the references. The quantity of effluents are based on BTU of fuel output. Each category of emissions is discussed below.

8.1 Air Impacts

Pollutants emitted to the air include NO_x , SO_x , particulates, hydrocarbons, CO and others (aldehydes, etc.). Table 8-1 gives total values while Table 8-2 attempts to identify quantities of each pollutant. The values are assumed to be those after controls are applied.

8.1.1 Coal

Air pollutants are essentially nil for underground mining and 7×10^3 lbs/MBTU for surface mining (Reference 8-6). The value is per million BTU of coal produced.

8.1.2 Coal Liquids

The range represents data from various sources and for various processes and various coal feeds (References 8-1, 8-2, 8-4, 8-6). A value of 0.3 can be derived for the national average from Reference 8-6. Since this is roughly in the middle of the range, the breakdown in Table 8-2 uses values from Reference 8-6.

8.1.3 Raw Shale

Upper and lower limits are for open pit and underground mining respectively. Values given in Table 8-2 are for open pit mining.

8.1.4 Shale Syncrude

The low value shown corresponds to the Tosco II operation from Reference 8-6 while the higher value is from Reference 8-1. Values in Table 8-2 are from Reference 8-6. The emissions from raw shale should be added to the shale syncrude to obtain the total emissions in producing a million BTU of shale liquid.

8.1.5 Methanol from Coal

The value shown is calculated from information in Reference 8-1.

TABLE 8-1

ENVIRONMENTAL IMPACT IN PRODUCTION #

<u>Fuel</u>	<u>Air*</u> lbs/10 ⁶ BTU	<u>Water</u> lbs/10 ⁶ BTU	<u>Solids</u> lbs/10 ⁶ BTU
Coal**	0-9x10 ⁻³ (8-6)	0-0.55 ⁽⁸⁻⁷⁾	1.0-200 ⁽⁸⁻⁶⁾
Coal Liquids	0.04-0.4 ⁽⁸⁻¹⁾⁽⁸⁻²⁾⁽⁸⁻⁴⁾⁽⁸⁻⁶⁾	0.12 ⁽⁸⁻²⁾⁽⁸⁻⁵⁾⁽⁸⁻⁶⁾	13 ⁽⁸⁻⁶⁾ -14 ⁽⁸⁻¹⁾
Shale Liquids			
Raw Shale	1.5x10 ⁻³ -3.6x10 ⁻³ ⁽⁸⁻⁶⁾	0 ⁽⁸⁻⁵⁾⁽⁸⁻⁶⁾	0.06-160 ⁽⁸⁻⁵⁾⁽⁸⁻⁶⁾
Syncrude	0.2 ⁽⁸⁻⁶⁾ -0.4 ⁽⁸⁻¹⁾	0-5x10 ⁻⁴ ⁽⁸⁻¹⁾⁽⁸⁻⁷⁾	320 ⁽⁸⁻⁶⁾ -520 ⁽⁸⁻¹⁾
Methanol from Coal**	0.14	0-0.25	13-23
Hydrogen from Coal***	0.12	0-0.2	11-19
Ammonia from Coal•	0.17	0-0.28	15-26
Methane from Coal	0.34 ⁽⁸⁻⁴⁾ -0.6 ⁽⁸⁻⁶⁾	0-0.16 ⁽⁸⁻⁶⁾	13 ⁽⁸⁻²⁾⁽⁸⁻⁶⁾ -19 ⁽⁸⁻²⁾
Electricity from Coal	1.9 ⁽⁸⁻⁸⁾⁽⁸⁻⁹⁾	0****	22-67 ⁽⁸⁻⁸⁾

* See Table 8-2.

** Does not include coal lost in cleaning or left in mine.

*** Prorated from Methanol.

Values are pounds of emissions/10⁶ BTU of fuel output. For coal and shale derived fuels, the emissions from mining should be added to the fuel production emissions and corrected for the process thermal efficiency.• Prorated from H₂.

•• Prorated from Coal Liquids.

**** Water assumed to be ponded.

TABLE 8-2

DETAILS OF AIR POLLUTANTSLBS. OF EMISSIONS/ 10^6 BTU OF FUEL OUTPUT

<u>Fuel</u>	<u>SO_x</u>	<u>NO_x</u>	<u>Particulates</u>	<u>Hydrocarbons</u>	<u>CO</u>	<u>Other</u>
Coal (8-6)	3.6×10^{-4}	5×10^{-3}	1.7×10^{-4}	5×10^{-5}	3×10^{-3}	8×10^{-5}
Coal Liquids (8-6)	0.04	0.23	9×10^{-3}	9×10^{-4}	7×10^{-3}	8×10^{-4}
Raw Shale (8-6)	9×10^{-5}	1×10^{-3}	4×10^{-5}	1×10^{-4}	7×10^{-4}	1×10^{-5}
Shale Syncrude (8-6)	0.11	0.04	5×10^{-4}	0.04	4×10^{-5}	3×10^{-4}
Methanol From Coal (8-1)	0.05	0.08	7×10^{-3}	1.3×10^{-3}	-	-
Hydrogen From Coal	0.04	0.07	6×10^{-3}	1×10^{-3}	-	-
Ammonia From Coal	0.06	0.1	8×10^{-3}	1.4×10^{-3}	-	-
Methane (8-6) From Coal	0.09	0.4	0.05	6×10^{-3}	0.02	1×10^{-3}
Electricity (8-8) (8-9) From Coal	1.2	0.7	0.01	0.01	0.04	2×10^{-4}

8.1.6 Hydrogen from Coal

Values prorated from methanol using the ratio of the heating value of methanol to the heating value of the hydrogen that could be produced from the CO and H₂ used to make methanol (0.834).

8.1.7 Ammonia from Coal

The value for ammonia is obtained by multiplying the value for hydrogen from coal by 1.4, the ratio of the thermal efficiency of H₂ to that of NH₃.

8.1.8 Methane from Coal

The higher value is the lowest value given in Reference 8-6 for the national average for several processes. The lower limit is from Reference 8-4. The process with the maximum value from Reference 8-6 is used in Table 8-2.

8.1.9 Electricity from Coal

Values are from References 8-8 and 8-9 and assume limestone scrubbing for particulate and SO_x removal.

8.2 Emissions in Water

8.2.1 Coal

The maximum value for pollutants to water was taken from Reference 8-7. The solids consist essentially of silt (suspended and dissolved). Emission to natural water sources could be reduced to zero by ponding.

8.2.2 Coal Liquefaction

The maximum value for coal liquefaction is reported in References 8-5 and 8-6 for the national average; the minimum is from Reference 8-7. The largest component of pollutants in effluent water is total dissolved solids (TDS) and this comes mainly from cooling tower blow down. For a 91,000 B/D H-Coal liquefaction plant, the cooling tower blow down is ca 10⁶ lbs/day (Reference 8-2). If this water contains 2000 ppm dissolved solids, then the output is 0.04 lbs/10⁶ BTU, which is the same order of magnitude as the number from Reference 8-5 and 8-6. The numbers quoted for TDS in the case of solid solvent refined coal (1.1 lb/MBTU) in References 8-5 and 8-6 is believed to be too high and is not used in Table 8-1. The numbers reported in Reference 8-6 for the CSF and SRC (synthetic crude) are very close so are not listed separately.

8.2.3 Raw Shale

References 8-5 and 8-6 show no pollutants to water. Any water containing dissolved solids is to be used for dust control and reclamation. It is difficult to see, however, how the disturbance of the shale will not result in run-off or seepage that could contaminate ground water.

8.2.4 Shale Syncrude

Reference 8-6 assumes the contaminated water from the plant will be used to moisturize spent shale and thus no water effluents are present. The upper figure of 5×10^{-4} lbs/MBTU is the TDS in the contaminated water used on the spent shale (Reference 8-1).

8.2.5 Methanol from Coal

The values given for methanol from coal are prorated from values for coal liquids based on the energy efficiency of conversion.

8.2.6 Hydrogen from Coal

The values shown in Table 8-1 for hydrogen from coal are derived by multiplying the methanol numbers by the ratio of the heating value of methanol to the heating value of the hydrogen that could be obtained from the CO and H₂ used to produce methanol.

8.2.7 Ammonia from Coal

The residuals for ammonia are prorated from hydrogen by a factor of the ratio of their thermal efficiencies (1.4).

8.2.8 Methane from Coal

The upper value in Table 8-1 is taken as the highest value from Reference 8-4 and 8-6. The lower value of zero assumes, of course, that contaminated waste waters are impounded.

8.2.9 Electricity from Coal

Contaminated water is assumed to contain products from flue gas desulfurization and to be ponded.

8.3 Solids

The quantity of solids from coal and shale operations depends on the inorganic content of the raw materials.

8.3.1 Coal

The upper figure given is the largest sum of applicable operations given in Reference 8-6 (auger mining and beneficiation) for controlled conditions on a national basis. The lower number is also calculated from Reference 8-6 and assumes strip mining with minimum beneficiation. Both upper and lower limits are dominated by mining.

8.3.2 Coal Liquefaction

The lower number in this listing is the national average from Reference 8-6. The high limit is the largest number calculated from information from Reference 8-7. In coal liquefaction, the largest source of solids is the ash and this would be essentially the same for all processes. (Some factor could be included for thermal efficiency, but this is very sensitive to design assumptions.)

8.3.3 Shale

The lower and upper limits in Table 8-1 are from Reference 8-6 and represent, respectively, underground versus open pit mining. The numbers are per 10^6 BTU produced.

8.3.4 Shale Syncrude

The lower limit is from Reference 8-6 and the higher number is from Reference 8-7. The spent shale rock is the major solid effluent.

8.3.5 Methanol from Coal

Values prorated from coal liquids using thermal efficiencies.

8.3.6 Hydrogen from Coal

Values prorated from methanol using the ratio of the heating value of methanol to the heating value of the hydrogen that could be obtained from the CO and H₂ used to make methanol.

8.3.7 Ammonia from Coal

Limits for ammonia are calculated by multiplying hydrogen from coal numbers by 1.4, the ratio of the thermal efficiency of H₂ to that of NH₃.

8.3.8 Methane from Coal

The lower value of the solids from high BTU coal gasification is taken from References 8-2 and 8-6 for Northwest coals. The high limit is from Reference 8-2 for the CO₂ Acceptor Process converting lignite. The high number results from disposal of spent acceptor.

8.3.9 Electricity from Coal

The lower limit is for a power plant without FGDS while the upper limit assumes FGDS with once-through limestone scrubbing. If the scrubber effluent is assumed to be ponded, then the solids output would be nil.

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9. IN-USE EMISSIONS WITH ALTERNATIVE FUELS

B. Kraus
W. Herbst

An evaluation of alternative fuels for non-highway transportation must take into consideration the potential environmental effects from the use of these fuels in the powerplants for which they were intended. While the emission impact of each fuel/powerplant combination, not ruled out by non-emission considerations, needs to be considered, it is of interest to look at the contribution of non-highway transportation to the total emission burden. This gives a measure of the global impact which, even if small, would still require that the effects on local geographic regions be considered.

9.1 Non-Highway Transportation Contribution to U. S. Emissions

The pollutants of prime interest, for which ambient air quality and/or emissions standards have been legislated are particulates, sulfur oxides (SO_x), nitrogen oxides (NO_x), hydrocarbons (HC), and carbon monoxide (CO). A non-regulated pollutant class of considerable current interest is the polycyclic organic compounds of which benzo- α -pyrene (BaP), a known carcinogen, is most commonly studied.

In order to ensure the best control strategy for meeting ambient air quality regulations legislated by Congress, the U. S. Environmental Protection Agency maintains a data bank of emission factors from various sectors of activity such as industrial, transportation, etc. This data bank, the National Emissions Data System (NEDS) gives estimates of the emissions contribution of the non-highway transportation sector. Table 9-1 contains an estimate of the emissions in the U. S. for 1973 of particulates, SO_x , NO_x , HC, CO, and BaP in millions of tons per year for railroads, aircraft, and vessels. Emissions from pipeline transportation are not specifically identified in the NEDS. Emissions from the industrial sector derived from the use of natural gas have been taken as an estimate for the pipeline mode. BaP emissions in Table 9-1 have been derived from a 1972 National Science Foundation study of polycyclic organic matter in conjunction with the fuel usage factors in the four non-highway transportation modes.

From Table 9-1, it appears that the contribution to total U. S. emissions ranges from as little as 0.1% for BaP to as much as 6% for NO_x . In terms of the individual pollutants, over half of the particulates would appear to come from aircraft, while the railroads are the major emitters of sulfur oxides and nitrogen oxides. Hydrocarbon emissions are more evenly divided among three of the four modes, pipeline transportation being generally a minor emitter of all the pollutants. Marine transport is the chief contributor to both CO and BaP.

A comparison of the results of Table 9-1 with those from other references, as is shown for particulates in Table 9-2, makes it clear that there is substantial uncertainty in the emissions of these sources. In

TABLE 9-1

U. S. EMISSIONS, MILLIONS TONS/YR.1973

<u>Transportation</u>	<u>Particulates(c)</u>	<u>SO_x(c)</u>	<u>NO_x(c)</u>	<u>HC(c)</u>	<u>CO(c)</u>	<u>BaP(d)</u>
Grand Total(a)	15.9	32.7	21.7	23.8	97.0	900 x 10 ⁻⁶ (e)
Railroads	0.057	0.130	0.846	0.215	0.297	0.32 x 10 ⁻⁶
Aircraft	0.162	0.038	0.155	0.486	0.836	0.24 x 10 ⁻⁶
Marine Vessels	0.025	0.102	0.194	0.367	1.084	0.50 x 10 ⁻⁶
Pipelines(b)	0.002	0.010	0.185	0.046	0.028	0.10 x 10 ⁻⁶
Sub-Total	0.246	0.280	1.380	1.114	2.245	1.16 x 10 ⁻⁶
% of Grand Total	1.55	0.856	6.36	4.68	2.31	0.12

(a) Petroleum, coal, chem. processes, waste disposal, etc.

(b) Natural gas, industrial.

(c) Derived from May 1976 report of the National Emissions Data System.

(d) Benzo(a)pyrene-estimated this study.

- Emission factors from: "Particulate Polycyclic Organic Matter"
National Academy of Science--1972
Committee on Biological Effects of Atmospheric
Pollutants
- Diesel trucks--62 µg/gal (page 16)--use for railroad, pipeline and marine
diesels.
- Aircraft--100 µg/10⁶ BTU (page 23)
- Oil-fired boilers--100-900 µg/10⁶ BTU (page 23)--use 100 for aircraft, 500
for marine residual
- Gas premixed burners--100 µg/10⁶ BTU (page 23)--use for pipeline, natural
gas
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Transportation Energy Conservation Data Book, 1977.

(e) From "Preferred Standards Path Report for Polycyclic Organic Matter,"
October 1974, EPA page viii (includes coal refuse fires, residential
furnaces, coke production, vehicle disposal, etc).

TABLE 9-2COMPARISON OF PARTICULATE EMISSION ESTIMATES

U. S. Million Tons/Year--1973

<u>Transportation</u>	<u>Ref. A</u>	<u>Ref. B</u>	<u>Ref. C</u>	<u>Ref. D</u>
Grand Total	15.9(e)	122(f)		
Railroads	0.057	0.22		0.055
Aircraft	0.162	0.03	0.03	
Fessels	0.025	0.15		
Pipelines	0.002	--		

Ref. A National Emissions Data System (NEDS), May 1976.

Ref. B APCA 25(7) 699 (1975)--Primary and Secondary Particulates as Pollutants by Fennelly, P. F.

Ref. C The Effects of Smoke Suppressant and Corrosion Inhibiting Fuel Additives on the Particulate and Gaseous Emissions from a Utility Gas Turbine by Herish, S., et al., ASMA 78-GT64.

Ref. D Unpublished data, based on heavy duty diesel truck engines; emission factor 3.4 gms particulates per kilogram of fuel.

(e) Petroleum, coal, chemical processes, waste disposal, etc.

(f) Includes natural dusts, ocean salt spray, etc.

fact, emissions for a particular mode can vary by a factor of five when comparing different sources of data. Even the relative contribution of the several modes varies to a great extent. While the NEDS makes the aviation mode by far the major source of particulates, railroads are the major contributor and aircraft the least in another reference. Nevertheless, despite this variation, the literature is consistent in showing non-highway transportation to be a relatively minor contributor to the total U. S. emission burden. If this were the only emission consideration of importance, the choice of alternate fuels would not likely be constrained by the emissions impact. In actuality, particular modes of non-highway transportation can impact to a far greater extent in localized areas than what would be imagined from a nationwide viewpoint. The airplane can be the overriding source of particulates in areas contiguous to airports. Changes in aviation fuels which would significantly increase such emission would therefore need to be considered also from that point of view. Similar arguments apply to the railroad and marine transportation and probably to a lesser extent to pipeline pump stations.

9.2 Emissions of Various Engine/Fuel Systems

In recent years, numerous investigators have begun to study the performance of various prime movers with non-conventional fuels. It is difficult to define in a quantitative fashion the effects on emissions from switching a particular transportation sector to alternative fuels and prime movers. Certain engine/fuel combinations have been studied from an emissions viewpoint. A good example of this is the combination of alcohols or alcohol-gasoline blends with the spark ignition engine.

9.2.1 Alcohol Fuels

The spark ignition engine plays only a minor role in aviation and pipeline transportation in the non-highway transportation, but it is the major consumer of fuels of any prime mover. Alcohols have been one of the alternative fuels suggested for this type of engine, either in relatively pure form or as an alcohol gasoline blend. A 1976 API study on the use of alcohol as fuels, (9-3) based on then existing literature, concluded that the somewhat leaner combustion possible with alcohols would lead to somewhat lower emissions of carbon monoxide, hydrocarbons, and nitrogen oxides. The emissions of aldehydes, very reactive species in photochemical oxidant formation, were however found to be higher than with gasoline. Reduction in the three primary gaseous pollutants, CO, HC, NO_x are claimed by several authors, (9-4,9-5,9-6) while others report only a lowering of NO_x. (9-7,9-8,9-9,9-10) Increased aldehyde emissions as well as unburnt methanol have been reported by Landman (9-6) and Lo Russo and Tabaczynski. (9-9) Reduced polynuclear aromatic hydrocarbon emissions both with pure methanol and methanol-gasoline blends were found in at least one study. (9-4) It is obvious that differences in emissions will occur when alcohols replace hydrocarbons as fuels in spark ignition engines.

Alcohols have also been studied in stratified charge spark ignition engines. (9-12,9-13) In these, hydrocarbons were found to increase. In this reference, (9-12) CO also increased with alcohols, while all three studies claimed a reduction in nitrogen oxides.

With the spark ignition engine, the use of methanol or ethanol, is likely to lead to reduced nitrogen oxide emissions. The effect of such alcohols on the emissions of CO and HC is dependent on the carburetion or richness setting, or on the effectiveness of post engine control devices. The latter, however, are not likely for application in non-highway transportation. Particulates from these engines are not a major problem with gasoline or alcohols. The absence of literature data on particulates serves to reinforce this point. Despite the probable increase of aldehyde emissions, it is not likely that emissions considerations would have a major impact on any decisions to use alcohols as fuels.

Another powerplant in which alcohols have been recommended as alternative fuels is the gas turbine. Because of their low heat content per unit weight, alcohols would only come into consideration in stationary or surface transportation use. Much as with the spark ignition engine, nitrogen oxides would appear to be lower than with conventional turbine fuels.(9-14,9-15,9-16) Carbon monoxide and hydrocarbons were said to increase, although such emissions from the gas turbine tend to be relatively low. Smoke, an important pollutant of the gas turbine, is apparently lower with alcohols.(9-15) Emissions would not be a major factor to consider on using alcohols in gas turbines. From the behavior of alcohols in homogeneous and heterogeneous combustion systems, it is not unreasonable to generalize that their use will on the whole probably be beneficial in terms of emissions. This would be true in stationary boilers, in the Stirling engine, the diesel(9-17,9-18) and the free piston engine. The potential carcinogenicity of emissions from heterogeneous combustion systems should be considered. This problem has been recognized with the diesel engine.(9-19) It is linked specifically to organic extracts of diesel particulates, which have shown very high activity in the Ames mutagenicity test. Since the effect of fuels on the activity of such organic extracts has not been defined, it is clear that large scale substitution of alternative fuels in combustion systems producing appreciable levels of particulates must first consider any impact in this area. Further work is needed.

9.2.2 Hydrogen

Hydrogen has been considered as a potential alternative fuel in both highway and non-highway transportation. In the spark ignition engine, hydrogen enrichment allows significantly leaner operation which directionally leads to reduced nitrogen oxide emissions. This is reported by several investigators.(9-20,9-21) Increased hydrocarbon emissions were however reported in the same studies. An all hydrogen-fueled spark ignition engine would likely give the benefit of reduced NO_x while also eliminating fuel-derived hydrocarbons.(9-22,9-23)

In the gas turbine engine, whether it be aviation or industrial, hydrogen enrichment would reduce CO, HC and smoke. Straight hydrogen operation would eliminate these constituents altogether.(9-14,9-24,9-25) The effect on nitrogen oxides is not clear, though it is not likely to be higher.

From an emissions viewpoint, hydrogen would likely lead to beneficial effects in use with any prime mover with which it is compatible, even without the consideration of the absence of CO₂ emissions.

9.2.3 Other Gaseous Fuels

With gaseous fuels other than hydrogen, emissions effects do not reveal clear benefits or debits. (9-14, 9-26, 9-27, 9-18) The exception to this may be ammonia. Past studies (9-28, 9-29, 9-30) are not consistent in the effect on nitrogen oxide formation. The potential problem of ammonia emissions cannot, however, be dismissed.

9.2.4 Coal and Shale Oil Liquid Fuels

The postulation of emissions effects derived from the use of "conventional" fuels which are derived from non-conventional sources such as coal or shale is very dependent on the assumptions made in terms of how conventional these fuels would be. It is, of course, possible to "refine" such fuels to be fully equivalent to those derived from petroleum. Hence, the emissions would be the same as from petroleum fuels. However, it may not be desirable to refine shale liquids and coal liquids to such an equivalent state because of cost. The emissions will depend on this degree of equivalency.

Two major factors are likely to appear with shale and coal liquid derived fuels which will impact on in-use emissions. One is the presence of relatively high fuel nitrogen levels in distillate and residual fuels which will translate directly into higher nitrogen oxide emissions. (9-31, 9-32, 9-33) This would be true for gas turbines, diesels, and stationary boilers. In at least some of these applications, certain combustion process modifications such as water injection and exhaust gas recirculation may at least partially offset the effect of the higher fuel nitrogen.

A second factor pertaining particularly to coal-derived fuels is the high aromatic content. This would in present day gas turbines lead to increased smoke emissions. (9-34, 9-35) The problem of carcinogenicity of particulates has already been discussed and is pertinent with these fuels. Directionally, the effect may well be similar in other prime movers. The need to establish the best compromise between refining of such fuels and the adaptation of the prime mover to handle them in an environmentally acceptable fashion is apparent.

9.2.5 Coal and Coal/Slurries

Use of coal or coal in combination with liquid fuels is from the viewpoint of fuel availability, an attractive option. In the non-highway transportation sector, coal has been used in rail and marine transport as boiler fuel. In powdered and slurried form, it has even recently been considered for diesel engines. (9-36, 9-37) Use of coal in direct use in any prime mover would unquestionably lead to a deterioration of the emissions picture, particularly as it concerns particulates. For the immediate future, the means to handle the in-use emissions problems associated with the direct use of coal are not available.

9.3 Summary of Emissions Effects of Fuels and Prime Movers

A qualitative summary of the emissions of various fuel/prime mover combinations compared to present fuels is shown in Table 9-3. The scale used is as follows:

- +2 -- Better in emissions of at least two pollutants
- +1 -- Better in emissions of one pollutant
- 0 -- Comparable to current fuel
- 1 -- Poorer than conventional fuels
- 2 -- Much poorer than conventional fuels

Since actual data on most of these is not available, estimates were made based on fuel properties and their effects on emissions in certain types of combustion systems, i.e., heterogeneous and homogeneous. It is safe to assume certain trends that are likely to occur with the use of particular fuels. The direct combustion of coal either straight or in liquid fuel slurries will lead to increased particulate emissions in any of the powerplants not normally fired with coal. Liquids produced from coal or shale will directionally increase nitrogen oxide emissions because of higher fuel nitrogen and probably more particulates due to increased aromaticity. On the whole, alcohols will probably improve the in-use emissions picture because of their beneficial effect on NO_x . Hydrogen will clearly improve emissions in-use in any prime mover because of reduced CO , CO_2 , HC , particulates and probably NO_x . The use of methane would also decrease in-use emissions in many prime movers.

TABLE 9-3

EMISSIONS EFFECTS OF FUELS AND PRIME MOVERS

Fuel	Otto Cycle		Diesel		Gas Turbine		Stirling	Free Piston	Steam
	Normal Spark Ignition	Stratified Charge	Marine Service (Low Speed)	Railroad (Medium Speed)	Stationary	Aircraft			
Petroleum									
- Present Specification	0	0	0	0	0	0	0	0	0
- Broadcut	-2	0	0	0	0	0	0	0	0
Coal	-2	-2	-2	-2	-2	-2	-2	-2	-2
Coal/Methanol Slurry	-2	-2	-2	-2	-2	-2	-2	-2	-2
Coal/Oil Slurry	-2	-2	-2	-2	-2	-2	-2	-2	-2
Coal Liquids									
- Gasoline	0	0	+1	+1	+1	+1	+1	+1	+1
- Diesel/Jet Fuel	-1	-1	0	0	+1	-1	-1	0	0
- Fuel Oil	-2	-2	-1	-1	-1	-2	-2	-1	-1
Shale Oil Liquids									
- Raw	-2	-2	-1	-1	-1	-2	-1	-1	-1
- Syncrude	-1	-1	0	0	0	-1	0	0	0
Methanol	+1	+1	+1	+1	+1	+1	+1	+1	+1
Hydrogen	+2	+2	+2	+2	+2	+2	+2	+2	+2
Ammonia	-1	-1	-1	-1	-1	-1	-1	-1	-1
Oxygenated Compound									
- Ethanol	0	0	+1	+1	+1	0	0	+1	0
- Higher Alcohols	0	0	+1	+1	+1	0	0	+1	0
Methane	+1	+1	+1	+1	+2	+1	+1	+2	+2
Hydrazine	0	0	0	0	0	0	0	0	0
Methylamine	0	0	0	0	0	0	0	0	0
Acetylene	0	0	+1	+1	+1	0	+1	+1	+1
Oil from Organic Waste	-1	-1	0	0	0	-1	0	0	0

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10. ENERGY EFFICIENCY IN PRODUCING AND TRANSPORTING ALTERNATE FUELS

E. N. Cart, Jr.

10.1 Introduction and Summary

One of the factors to consider in ranking the various alternate fuels is which fuels make the most efficient use of our national resources. To determine which fuels require the least amount of a given resource, it is necessary to estimate the thermal efficiency of the process used to produce the fuel from the resource (including the energy associated with liquefying a gaseous fuel, if necessary), and the energy required to transport the resource and the final fuel to the consumer. These factors are then combined in a systems approach to indicate the amount of a given resource that is needed to produce a certain amount of final product. The three major areas covered in this section are: (1) the thermal efficiency of the processes used to manufacture the fuels; (2) the energy required to transport the resources and fuels; and (3) the combination of items (1) and (2) in a systems analysis to indicate the amount of basic resources required.

The thermal efficiencies of the various processes used to manufacture alternate fuels are summarized in Table 10-1 for the non-renewable based fuels and in Table 10-2 for the biomass based fuels. Two efficiencies are shown in Table 10-1; an efficiency which accounts for only the liquid transportation fuel (ϵ_1), and the overall thermal efficiency (ϵ_2). Both efficiencies are defined in Section 10.2.1. The ϵ_2 efficiency is the one normally reported in the literature, but the ϵ_1 efficiency is also useful in indicating which fuels or processes may be best suited to producing liquid transportation fuels.

The biomass based fuels are shown in a separate table, since it is difficult to compare a renewable resource base with a non-renewable resource base. With a renewable base, it is also worthwhile to look at the output/input ratio--an indication of how much energy is obtained per the energy required to produce the fuel. For example, with ethanol from sugarcane, the energy output is about breakeven with the energy required to produce the ethanol. Of the three fuels considered, it appears that ammonia produced from sugarcane would be the most efficient use of biomass fuels.

In an attempt to put the biomass derived fuels on a thermal efficiency basis for comparison to the coal and shale based fuels, the heating value of the biomass was assumed at 7800 BTU/LB which then allows the thermal efficiency of the process to be calculated.

The ϵ_2 thermal efficiencies are illustrated in Figure 10-0 for three different resource bases--shale, coal and biomass. As noted, there is a range of thermal efficiencies reported in the literature for each fuel. There are several reasons for the range--type of coal used (in a

TABLE 10-1

SUMMARY OF PROCESSING THERMAL EFFICIENCIES -
NON-RENEWABLE BASED FUELS

<u>Fuel</u>	ϵ_1 -% (Liquid Fuel Only)	ϵ_2 -% (Total Thermal Efficiency)
Coal/Oil Slurry	97-98.5	97-98.5
Shale Oil - Upgraded	65	64-72
<u>Coal Based Fuels</u>		
- Liquids via		
+ Pyrolysis	15-28	57-70
+ Liquefaction	41-63	63-75
+ Indirect	30	50-60
- Coal Liquid Upgrading	70-92	70-92
- Methanol	39-56	52-56
- Ammonia		47-51
- Acetylene	27-29	46-48 (30-34 more likely)
- Hydrogen (g)		50-64
- Hydrogen - Liquefaction Step Only		44-58
- Methane (g)	48-68	55-78
- Methane - Liquefaction Step Only		83-91
<u>Other Energy Carriers</u>		
- Hydrogen - Electrolysis		30-33
- Electricity - Coal (conventional)		35-37
(new technology)		55-68
- Nuclear		32

(g) = gas

TABLE 10-2

SUMMARY OF PROCESSING THERMAL
EFFICIENCIES - BIOMASS BASED FUELS

<u>Fuel</u>	<u>Product Energy/ Process Energy Input (1)</u>	<u>ε₂ Thermal Efficiency</u>
Ethanol		
- Sugar cane	1.1	27
- Corn	0.42	25-36
Methanol		
- Sugar cane (pyrolysis)	2.1	28-43
Ammonia		
- Sugar cane (pyrolysis)	4	46

(1) See Section 10.2.12 for definition.

FIGURE 10-0

THERMAL EFFICIENCIES OF VARIOUS PROCESSES
USED TO MANUFACTURE ALTERNATIVE FUELS

coal based process), degree of heat integration, whether coal or by-products are used to generate electricity, etc. Also, for processes under development, the thermal efficiency tends to be overstated, since all aspects of the problem have not been fully defined and an in-depth engineering design is unavailable.

Also included in Figure 10-0, as a separate item, is the efficiency for upgrading of coal liquids, liquefaction of hydrogen, and liquefaction of methane. Of course, these efficiencies must be considered in conjunction with the basic process efficiency to arrive at an "overall" efficiency, which will be discussed later.

Several comments on Figure 10-0:

- In the coal liquids area, the liquefaction route was selected as representative. The pyrolysis and indirect methods have lower ϵ_1 efficiencies, and overall thermal efficiencies in the same range as the liquefaction route.
- The rather broad range associated with coal liquids upgrading reflects the range from (a) trying to upgrade coal liquids directly to current distillate specification, to (b) mixing coal syncrude into an existing refinery and allowing the plant to optimize the processing and feedstocks used for each product.
- Note the higher efficiency associated with methane liquefaction (82-91%) compared to hydrogen liquefaction (44-58%).

By combining the process thermal efficiencies with the energy requirement to transport the fuel, it is possible to calculate the amount of basic resource needed to supply a given amount of transportation fuel energy. Figure 10-1 shows the coal and shale based resource required to produce a million BTU's of final fuel. As expected, direct burning of coal is the most efficient way to use coal, if it can be accommodated in a prime mover. The next most efficient fuel, from a resource utilization standpoint, is coal/oil slurry. Coal distillate and liquid methane are the next most efficient, requiring about 1.88×10^6 BTU of coal to produce a million BTU of liquid transportation fuel. Methanol and ammonia require 2 and 2.15×10^6 BTU of coal to produce million BTU of liquid transportation fuel, respectively. Electricity, liquid hydrogen and acetylene require the largest amount of coal, of the alternate fuels considered.

To produce a million BTU of distillate from shale oil required 1.63×10^6 BTU of basic resource. Data on the biomass fuels are not included in this comparison due to the difference mentioned earlier between a renewable and a non-renewable resource.

FIGURE 10-1

BASIC RESOURCE REQUIREMENTS FOR SEVERAL ALTERNATE FUELS

10.2 Thermal Efficiency of Manufacturing Process for Alternate Fuels

In this section, the thermal efficiency for the manufacture of the various fuels is discussed. Also included is the energy for liquefaction of the gaseous methane and hydrogen. One of the first areas to consider is the definition and basis for calculating the thermal efficiencies.

10.2.1 Basis for Thermal Efficiency

There are several ways to define thermal efficiency, all of which are valid. For example, one efficiency would indicate the amount of initial resource that can be converted into energy in the form of the alternate fuel of interest. Thus:

$$\epsilon_1 = \frac{\text{BTU output of primary fuel}}{\text{BTU input of total resource}}$$

Figure 10-2 illustrates a process to produce methanol from coal. The efficiency in this case would be:

$$\epsilon_1 = \frac{272 \times 10^9}{692 \times 10^9} = 39.3\%$$

In this particular example, there are significant quantities of combustible products produced along with the primary fuel. These products could be used as fuels themselves, so that the total efficiency would be:

$$\epsilon_2 = \frac{\text{BTU output of total combustible product}}{\text{BTU input of total resource}}$$

For the example in Figure 10-2, the efficiency would be:

$$\epsilon_2 = \frac{272 + 110}{692} = 55.2\%$$

It should be noted that sulfur and ammonia have been excluded, even though ammonia is one of the alternate fuels being considered. In this particular case, the prime purpose is to produce methanol as a fuel--not ammonia.

In place of considering the by-products as a potential fuel, they could be used in some cases internally as fuel and back out part of the coal. In that case:

$$\epsilon_3 = \frac{\text{BTU output of primary fuel (methanol)}}{\text{BTU input of total resource} - \text{BTU content of combustible by-products}}$$

For the example in Figure 10-2:

$$\epsilon_3 = \frac{272}{692 - 110} = 46.7\%$$

FIGURE 10-2

EXAMPLE OF ENERGY EFFICIENCY CALCULATION

$$\epsilon_1 = \frac{\text{BTU Output of Primary Fuel}}{\text{BTU Input of Total Resource}} = \frac{272}{692} = 0.393 \text{ or } 39.3\%$$

$$\epsilon_2 = \frac{\text{BTU Output of Total Combustible Product}}{\text{BTU Input of Total Resource}} = \frac{382}{692} = 0.552 \text{ or } 55.2\%$$

The problem with this approach is that most times, the by-products have a higher current value in non-fuel applications but incremental demand in these applications may be quite different than in fuel applications.

There are two additional accounting rules which are important to consider.

1. Thermal efficiencies will be based on the gross heating values of the fuels. Either gross or net heating values could be used but a consistent set of units must be used. When considering the amount of energy required for each prime mover, it will be necessary to consider the net heating value since the costs of the fuels are expressed on a net heating value basis, while the efficiencies of the prime movers are also on a net basis. This final conversion will be made at the fuel/prime mover interface.
2. When electrical energy is required in a conversion process, the efficiency of the boiler-generator will be assumed to have an efficiency of 38%. Thus, the amount of coal needed to produce the electricity will be included. This will insure that processes that generate their electricity internally are on the same basis where external power is purchased.

In some cases ϵ_1 , ϵ_2 and ϵ_3 will be equal. For this study, ϵ_1 and ϵ_2 will be considered, assuming that sufficient data is available in the literature to allow this calculation to be made.

10.2.2 Coal/Oil Slurry

The energy requirements associated with preparation of a coal/oil slurry are mainly due to the coal grinding energy requirements. Garcia⁽¹⁰⁻¹³⁾ reports that this requirement can range from 25 to 250 kwh/ton to reduce the coal to a 4 micron powder. Other energy requirements would be associated with coal handling, pumping of the fuel oil and mixing of the coal and oil. Considering all of these factors, the overall thermal efficiency is 99-99.4% depending on the energy requirements for grinders. If the energy requirements to produce the electricity are included at a 38% thermal efficiency, the overall thermal efficiency drops to 97.4-98.5%. For purposes of this study, a value of 97% will be used.

10.2.3 Coal Liquefaction

The thermal efficiency of the various coal liquefaction processes will depend on several factors, such as type of coal used, degree of heat integration, nature of utilities, whether coal or by-product gas is used to generate electricity and steam, the method used to generate hydrogen, etc. The thermal efficiency, ϵ_1 and ϵ_2 , for the basic three types of processes described in Section 6 are summarized in Table 10-3.

Since ϵ_1 is a measure of the efficiency of a process to make the transportation fuel of prime interest, namely liquids in this case, the highest efficiency (41-63%) is for the direct liquefaction route, with

TABLE 10-3SUMMARY OF THERMAL EFFICIENCIES
FOR COAL LIQUEFACTION PROCESSES

	<u>ϵ_1</u>	<u>ϵ_2</u>	<u>Source</u>
<u>Pyrolysis</u>	15-28	57-70	10-2,10-3,10-4, 10-5
<u>Liquefaction</u>	41-63	63-73	10-2,10-6,10-7, 10-8,10-9,10-10
<u>Indirect</u>	30	69-73 ⁽¹⁾	10-2,10-11

-
- (1) These values appear to be too high, since the basic coal gasification process would have a 55-65 efficiency and the Fischer-Tropsch synthesis efficiency would probably be about 90%. Thus the range would be more like 0.5-0.6.

pyrolysis and indirect liquefaction (Fischer-Tropsch) having efficiencies in the 15-30% range. This would indicate that if the aim is to produce primarily liquid fuels from coal, that one of the liquefaction processes would be preferred. However, it is necessary to consider the other products that are produced, such as SNG and electricity, since these can be used to displace liquid fuels that may be used in other sectors, such as the industrial and electrical sectors. In this case, the thermal efficiency is in the 57-75% range for all three types of processes. Part of the difference in the range of thermal efficiency is due to the differences in hydrogen content of the liquid products.

For the purpose of this study, a thermal efficiency of 63% will be used for coal liquefaction, representative of the H-coal process shown in Figure 10-3. O'Hara(10-2) reported a thermal efficiency of 65%; and the study by Colorado Energy Research Institute(10-8) reported an efficiency of 67%, if put on the same basis as used in this study. This illustrates the range of efficiencies that are quoted for the same process in the literature.

10.2.4 Coal Liquids Upgrading

The thermal efficiency to upgrade coal liquids to specification products will depend on the properties of the coal syncrude (degree of hydrogen deficiency), how the hydrogen is produced, whether gasoline, diesel or jet fuel is the final product and the hydrogen content of the final product.

Tsaros(10-14) investigated producing specification jet fuel from coal using the CSF coal liquefaction processes. In one case, shown in Figure 10-4, the jet fuel was produced by hydrocracking the heavy oil from the CSF process. The hydrogen was generated by reforming of the high BTU product gas. In this particular process arrangement, the upgrading thermal efficiency was 70%.

If instead of producing the jet fuel from coal liquid, the refinery output was increased and the aromatic material produced from coal was added to the gasoline pool and some of the petroleum components diverted from catalytic reformer feedstock, the efficiency of the upgrading step would be increased to 87%. The upper limit would be to add the coal liquids to an existing refinery and allow the refiner to optimize his overall system. In this case, the thermal efficiency would be the same as an existing refinery, or 88-92,(10-8) depending on location of refinery, product slate, complexity of processing and type of crude processed.

10.2.5 Shale Oil Retorting and Upgrading

The thermal efficiency of producing fuels from underground mining of shale oil from three different processes ranged from 64-70%,(10-8,10-1) a narrow range considering the wide variation in the degree of refinement

FIGURE 10-3

H-COAL LIQUEFACTION PROCESS ENERGY BALANCE

10-12

FIGURE 10-4

MANUFACTURE OF JET FUEL FROM COAL-DERIVED HEAVY FUEL OIL

10-13

of the product from essentially no refining to almost complete refining. (10-8) For purposes of this study, the Tosco II process has been selected as typical of a mining-retort-upgrading process. The energy balance for the Tosco-II process is shown in Figure 10-5. The ϵ_1 efficiency (resource-to-syncrude) would be 65%, while the overall thermal efficiency, ϵ_2 , would be 72%. The overall efficiency neglects the latent and sensible heat in the spent shale. The product from the Tosco II process needs to be only fractionated to obtain diesel and kerosene products, while the gasoline would need to be reformed.

10.2.6 Methanol (Coal Derived)

The thermal efficiency of producing methanol from coal from several different references are summarized in Table 10-4.

TABLE 10-4

THERMAL EFFICIENCY OF METHANOL FROM COAL

<u>Reference</u>	<u>ϵ_1-%</u>	<u>ϵ_2-%</u>
10-15		
- Koppers-Totzek	52	52
- "New" Process	56	56
10-1	39	55
10-16	52	52

The data from Reference 10-1 is shown in Figure 10-6, which shows that from this particular process, tar, oil, and naphtha are produced which accounts for the difference between ϵ_1 and ϵ_2 . For this study, the 52% thermal efficiency from Reference 10-15, using the Koppers-Totzek process as a developed process, will be used. As noted, development of a more efficient coal gasification process could increase the efficiency to 56%.

10.2.7 Ammonia (Coal Derived)

The thermal efficiency of producing ammonia from coal is 47% using the Koppers-Totzek gasification process and 51% if a "new," more efficient coal gasification is developed. (10-15) For this study, the 47% efficiency will be used.

10.2.8 Acetylene (Coal Based)

The thermal efficiency of producing acetylene from calcium carbide, which is produced from coal, is 27-29% for ϵ_1 and 46-48% for ϵ_2 . The range reflects the uncertainty of the amount of acetylene generated from calcium

FIGURE 10-5

TOSCO II OIL SHALE RETORTING AND UPGRADING ENERGY BALANCE

10-15

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carbide. These efficiencies also reflect the energy required to produce the electricity. The detail energy flows are shown in Figure 10-7. As shown in Figure 10-7, the energy balance reflects the energy used in calcining the limestone to CaO , based on a value of 2250 BTU per pound of CaO . (10-18) Since the by-product is a medium BTU gas, it is unlikely that this energy could be utilized, except within the process. In that case, the efficiency would be 34% if all the by-product gas was used and 30% if only the 500 BTU/ft³ gas was used to calcine the limestone. The ϵ_1 value is probably more representative of the overall efficiency for this particular case and will be used for this study.

10.2.9 Hydrogen

10.2.9.1 Coal

The thermal efficiency of producing hydrogen from coal will depend on the coal gasification process that is used, the degree of process integration to recover waste heat and generate electricity, etc. A comparison of the thermal efficiencies reported in the literature is shown in Table 10-5. As can be seen, most of the literature results show a thermal efficiency of about 50-60% for the commercially proven processes, with the possibility of increasing this to 64-66% with an improved gasification process. Where external electrical energy is required, the efficiencies reflect the resources necessary to generate the electricity, assuming a 38% efficiency for the generation step. For the purpose of this study, the value quoted in Reference 10-15 of 60% will be used.

10.2.9.2 Electrolysis

Another way to produce hydrogen is by electrolysis, as described in Section 6. The thermal efficiency for the solid polymer electrolyte electrolytic cell is 30%, based on data from Reference 10-15. The low efficiency is due to the large electrical energy requirements for the process with the assumed 38% thermal efficiency for electricity generation. England, et al (10-26) give a similar efficiency of 33% for nuclear/electrolysis. They also estimate around 33% process efficiency for nuclear/thermochemical and solar/thermal/electrolysis.

10.2.9.3 Liquefaction

To use hydrogen as a transportation fuel most likely will require storage of the material within the vehicle as a liquid. To liquefy hydrogen for a transportation fuel requires a considerable energy penalty, particularly if one includes the resource requirements to generate electricity. For storage as a liquid, hydrogen must be cooled to -423°F. The thermal efficiency for liquefying hydrogen from several literature references are summarized in Table 10-6. As noted in the literature, the thermal efficiency of the basic liquefaction process ranges from 71 to 77%. Including the efficiency of electricity generation reduces the overall thermal efficiency to the 48-58% range. Part of this variation is due to differences in the estimate of actual electrical energy required compared to the theoretical work, hydrogen losses in liquefaction, degree of integration

FIGURE 10-7

ENERGY FLOWS IN PRODUCING ACETYLENE
FROM CALCIUM CARBIDE GENERATED FROM COAL

10-18

$$\epsilon_1 = \frac{13.2}{4.72 + 22.8 + 21.1} = 0.27$$

$$\epsilon_2 = \frac{13.2 + 6.5 + 2.8}{4.72 + 22.8 + 21.1} = 0.46$$

Source: Based on Data in Ref. 10-17.

TABLE 10-5COMPARISON OF THERMAL EFFICIENCIES FOR
PRODUCING GASEOUS HYDROGEN FROM COAL

<u>Reference</u>	<u>Process</u>	<u>Thermal Efficiency</u> ϵ_2
10-15	K-T	60
	"New"	64
10-19	*	59
10-20	K-T	50
10-21	*	56
10-22	*	59
10-23	*	55
10-7	*	59
10-3	*	58
10-24	K-T	57
	U-GAS	66
	Steam-Iron	59(1)
10-25	*	58

* Not identified.

(1) Using byproduct gas to generate electricity at 38% efficiency. ϵ_1 for this process is 45%.

TABLE 10-6THERMAL EFFICIENCY FOR LIQUEFYING HYDROGEN

<u>Reference</u>	<u>Thermal Efficiency of Basic Liquefaction Process</u>	<u>Thermal Efficiency Including Electrical Generation Efficiency</u>
10-20	71	53(ϵ_2), 50(ϵ_1)
10-22	77	
10-23	76	55
10-7	—	48
10-3	—	44(ϵ_2)
10-25	77	58

assumed with the gasification complex, and whether refrigerant losses are included. For example, Boggs(10-26) gives the following comparison between the theoretical and actual energy required to liquefy a pound of hydrogen.

	<u>kwh/Pound</u>
Theoretical work	1.77
Actual	4.89
Practical	5.67

The practical electrical requirements include the electrical requirements for production auxiliaries such as cooling towers and thawing heaters, and the lighting, heating and air conditioning of the plant. Hallett(10-27) reports an electrical energy requirement of 4.46 kwh/pound of H₂ liquefied. For this study, the practical electrical energy requirements of 5.67 kwh/pound will be used, in conjunction with the other information from Hallett,(10-27) to arrive at an efficiency of 53%. The details are shown in Figure 10-8. The 53% is also in line with the value reported by Union Carbide.(10-28)

10.2.10 SNG

10.2.10.1 Coal

The thermal efficiency of producing SNG from coal will be dependent on the process used, the type of coal used, the reactivity of the coal, whether product gas or coal is used as the boiler fuel, and several other factors. The thermal efficiencies of some of the different gasification processes are summarized in Table 10-7. For the commercially proved processes, the ϵ_1 efficiency is around 55-65%, while with the advanced processes, the ϵ_1 efficiency could increase. The ϵ_2 efficiency is higher, around 65-70% for the older processes and could be higher for the newer processes. Typical energy flow rates for the Lurgi process are shown in Figure 10-9. For this study, the older type processes such as the Lurgi process, will be used to show the thermal efficiency.

10.2.10.2 Liquefaction

If SNG is used as a transportation fuel, the material most likely will need to be liquefied, except for pipeline use. The energy requirements to liquefy methane are not as severe as to liquefy hydrogen primarily because methane requires a liquefaction temperature of -259°F, compared to -423°F for hydrogen. The thermal efficiency of liquefying SNG reported in the literature ranges from 83 to 91%, as shown in Table 10-8. For the purpose of this study, a value of 86% will be used (Reference 10-37) to be consistent with the cost of liquefaction given in Section 7.

FIGURE 10-8

THERMAL EFFICIENCY OF HYDROGEN LIQUEFACTION

Btu/Pound of Hydrogen Produced

$$\epsilon_2 = 60.99/63.43 + 1.1 + 50.9 = 0.53$$

If exclude electrical generation efficiency:

$$\epsilon_2 = 60.99/63.43 + 1.1 + 19.35 = 0.73$$

Source: Based on Data in Ref. 10-27 and 10-26.

TABLE 10-7SUMMARY OF THERMAL EFFICIENCIES
OF COAL GASIFICATION PROCESSES (1)

<u>Process</u>	<u>ϵ_1</u>	<u>ϵ_2</u>	<u>Reference</u>
Lurgi	53 ⁽²⁾	66	10-29
	55 ⁽³⁾	66	10-29
	59	71 (single feed)	10-30
	54	--	10-31
	--	66	10-8
	54	67	10-20
Synthane	59	63	10-32
BIGAS	65	65	10-33
HYGAS	60	65	10-34
U-GAS	68	68	10-35
Conoco CO ₂	66	67	10-30
PERC-Dry Feed	48	55	10-30

-
- (1) Most of these efficiencies are for a sub-bituminous type coal. With a bituminous coal, the efficiency would be lower, with ϵ_2 in the 50-60% range.
- (2) Based on burning fuel gas to generate electrical power.
- (3) Based on a coal-fired boiler to generate electrical power.

FIGURE 10-9

THERMAL EFFICIENCIES FOR LURGI AND IGT STEAM-O₂ SNG PROCESSLurgi

$$\epsilon_1 = \frac{10.1}{15.3 + 3.1} = 0.55$$

$$\epsilon_2 = \frac{10.1 + 1.6 + 0.3 + 0.1}{18.4} = 0.66$$

Source: Ref. 10-29

TABLE 10-8SUMMARY OF SNG LIQUEFACTION THERMAL EFFICIENCIES

<u>Reference</u>	<u>Thermal Efficiency</u>
10-28	90
10-7	83
10-3	83
10-24	91
10-37	86-90, ex storage losses
	83-87, including storage losses

10.2.11 Electric Power Generation

The thermal efficiencies of several different types of power plants are summarized in Table 10-9. A large, conventional, coal-fired unit will have a thermal efficiency of around 37%. This represents the net plant electrical output divided by the coal higher heating value, i.e., "coal pile to bus bar." The efficiency of the H-coal fuel does not include the efficiency lost in preparing fuel for the power plant. If this loss is included, the efficiency based on coal mined, drops to around 38%.

Some of the more advanced technologies, such as a potassium topping cycle, with pressurized fluid bed combustion, and MHD are projected to have thermal efficiencies at the 50% level.

Nuclear and solar-steam electric efficiencies are shown in the bottom of this table for comparison. These efficiencies are around 33%.

For this study, a thermal efficiency of 38% will be used. This is a little higher than the value quoted for new, conventional coal-fired power plants, but lower than some of the more advanced technologies which may be developed after 1990. The 38% is in line with the value given by Frabetti(10-39) for a coal or oil-fired power plant, and higher than the 32% given by the Colorado Energy Research report,(10-8) which is typical of older type units.

10.2.12 Biomass-Derived Fuels

The energy analysis of biomass materials is somewhat different from that for a non-renewable resource such as coal or shale oil, discussed in previous sections. With biomass materials, one value reported in the literature is the ratio of energy in the product to the energy consumed in the process, including the energy used in the agricultural production. It is important to consider the quality level of the various inputs and outputs as well. In this type of analysis, the ratio is generally greater than one, implying that the useful energy output exceeds the process energy input. Of course, this type of analysis does not include the energy that has come from the sun and been converted to plant material through photosynthesis. To put the thermal efficiencies on a similar basis with the coal and shale oil values, a heating value of the biomass material will be assumed

TABLE 10-9

THERMAL EFFICIENCIES OF ELECTRIC
POWER GENERATION FACILITIES

	<u>Power Plant Thermal Efficiency-%</u>
Conventional Coal Fired	0.37
AFB	0.37
PFB	0.40
Potassium Topping - Conventional	0.45
- PFB	0.49
Combined Cycle - LHVG	0.396
- H-Coal	0.51 [*]
MHD	0.50
LWR Nuclear	0.32
Solar Steam - Electric - Base Load NW	0.33

^{*}Does not include efficiency lost in preparing the fuel. If this is included, efficiency drops to 38%.

Source: 10-38 and 10-19

to allow a calculation of the thermal efficiency quoted in previous sections. The following sections discuss the production of ethanol from sugarcane and corn, and the production of methanol and ammonia from sugarcane via pyrolysis.

10.2.12.1 Ethanol from Sugarcane

Lipinsky, et al. have made an energy analysis for producing ethanol from sugarcane.(10-40) The analysis takes into account the energy used in producing the sugarcane (tractor fuel, fertilizers and pesticides). The energy analysis reported by Lipinsky is shown in Figure 10-10, with the energy values shown as million of BTU's per ton of sugarcane (dry weight basis). It is also important to consider the quality of energy involved, with the ethanol being considered high, and bagasse as a lower quality source of energy.

As shown in Figure 10-10, the bagasse that is left after the juice is extracted is used as fuel for the power plant to generate the electricity and steam required. Assuming an 80% efficiency means that the waste product can provide 5.2×10^6 BTU/ton of sugarcane of the 8 million BTU of energy required for crushing, evaporation, distillation and stillage drying. Therefore, an additional 2.8 million BTU of energy must be provided to complete the energy balance. If the same boiler efficiency of 80% applies, then 3.5 million BTU's of coal or oil would be needed. Therefore the 5.6 million BTU's of ethanol require 5.3 million BTU (1.8 million BTU agricultural production plus 3.5 million BTU's of coal or diesel oil) of input. Thus, the energy content of the ethanol produced from sugarcane is slightly more than the energy consumed in the production process.

To compare the process efficiency with coal and shale oil, it is necessary to make an assumption on the heating value of the sugarcane. For a biomass heating value of 7800 BTU/pound (dry), the ϵ_1 efficiency would be about 27%. This calculation ignores the metabolizable energy in the stillage, since it is a different type of energy. However, this is a very low level of energy output and would not affect the overall thermal efficiency. It is also unclear whether energy to dry the bagasse before feeding it to the power plant has been included in the literature reference. To take the bagasse from 38% moisture to a dry basis would require about 0.3 million BTU per ton of sugarcane and reduce the thermal efficiency to 26%; therefore, it is not a critical uncertainty in this case.

10.2.12.2 Ethanol from Corn

There are varying opinions on the net energy balance of ethanol production from corn. Scheller has made a net energy balance which assumes that the stalks, cobs, and husks can be used to generate the process steam and electricity(10-41). With this assumption, he obtains a positive energy balance. However, two other references (10-44,10-45) conclude that the energy balance is negative, mainly based on the assumption that fossil energy will be required to provide the steam and electricity since there is no commercial process that

FIGURE 10-10

ENERGY ANALYSIS OF ETHANOL PRODUCTION FROM SUGARCANE

Units: Million Btu/ton Sugarcane (Dry Weight Basis)

$$\text{Product Energy/Process Energy Input} = \frac{5.6}{1.8 + 3.5} = \frac{5.6}{5.3} = 1.06$$

$$\epsilon_1 = \frac{5.6}{1.8 + 15.6^{(1)} + 3.5} = 0.27$$

(1) Based on assumed 7800 Btu/pound (dry) heating value for biomass.

FIGURE 10-11

ENERGY ANALYSIS OF ETHANOL PRODUCTION FROM CORN

$$\text{Product Energy/Process Energy} = 198,911/119,289 + 349,950 = 0.42$$

$$E_1 = 196,109/119,289 + 349,950 + 341,750 \text{ (Energy in Corn)} = .24$$

If consider only energy in corn that produces the alcohol - which is 59% of the total.

$$E_1 = 196,109/70,380 + 349,950 + 201,632 = .32$$

If include cattle feed

$$E_2 = \frac{196,109 + 2,802 + 116,860}{119,289 + 349,950 + 341,750 + 58,900} = .36$$

Source: Adapted from Ref. 10-40.

utilizes stover as its energy source(10-45). Also, removal of the crop residues would require energy for collection and handling and also excessive removal could lead to soil degradation and additional fertilizer energy requirements(10-44). A comparison of the ratio of product energy (ethanol only) to the process energy input (assuming fossil fuel for steam and electricity) is shown below.

<u>Reference</u>	<u>Product Energy/Process Energy</u>
10-41	0.42
10-44	0.4
10-45	0.44 - 0.49

In general, there is fairly good agreement, once the results are put on a common basis.

The energy analysis by Scheller(10-41) is shown in Figure 10-11, with the energy values shown as BTU/bushel of corn. The balance is shown with fossil fuels providing the energy for steam and electricity, whereas in the reference it was assumed that corn stalks would provide the energy. The use of fossil fuels were assumed for the reasons given above. Agricultural production and transportation of the corn requires 119,289 BTU/bushel of corn. The energy required in the fermentation plant to produce the ethanol is 279,960 BTU/bushel of corn. Assuming an 80% efficiency for the utility section means that 349,950 BTU/bushel of fossil energy would be required. The products are ethanol (196,109 BTU/bushel of corn), fusel oil and aldehydes (2802 BTU/bushel of corn) and grain-by-products.

The ratio of product energy to process energy is 0.42 based on ethanol as the main product. Using the heating value for corn (341,750 BTU/bushel) reported in the article, the thermal efficiency is 24%, excluding the digestible energy content in the by-product grains. However, in the fermentation process only the starch fraction of the corn is converted to alcohol. The rest of the grain remains as a high protein feed, distillers grain. On this basis, only 59% of the energy is used to produce a bushel of corn (70,380 BTU) and 59% of the energy content of the corn (201,632 BTU) should be charged to alcohol production(10-45). On this basis, the thermal efficiency increased to 32%. If the energy consumption associated with the production of distillers' by-product grains is included, and the digestible energy content of the by-product grains is included, the thermal efficiency increases to 36%.

10.2.12.3 Methanol

The Lipinsky study(10-40) presents information on the manufacture of methanol via gasification of the bagasse (Purox process) to produce a synthesis gas and then converting the CO and H₂ to methanol via conventional technology. An energy balance has been developed based on information in the Lipinsky report and is shown in Figure 10-12. Several assumptions were made to arrive at the estimate shown. It was assumed that the heating value of the bagasse was 7800 BTU/pound (dry) and that the

agricultural requirements that could be attributed to the bagasse were proportional to the weight fraction of bagasse to the sugarcane production. It was also assumed that electricity was generated from coal with a 38% efficient power plant. The data from the Lipinsky report did not show any steam consumption so it was assumed that the steam from the turbine generators was used in the Purox process and methanol synthesis.

As shown in Figure 10-12, the production of methanol from gasification of a biomass material has a thermal efficiency of around 29% and a net energy ratio (output/input) of 2.1. Thus, the production of methanol via gasification appears to be more efficient than the production of ethanol via fermentation.

Reed(10-42) reported a thermal efficiency of producing methanol from waste of about 34% and 37% when producing methanol from dry wood. These are somewhat lower efficiencies than reported by Stanford Research Institute(10-19) of 43% for a conceptual advanced gasification system.

10.2.12.4 Ammonia

The Lipinsky study(10-40) also allows one to make an estimate on the energy requirements to produce ammonia from biomass. Figure 10-13 shows the energy analysis that has been developed using information from the Lipinsky report. It is assumed that the by-product gas will be used to provide most of the energy requirements, which greatly reduces the external energy requirements. On this basis, the output/input ratio is 4, and the thermal efficiency 46%, about the same as for producing ammonia from coal.

Thus, of the three fuels considered as being produced from biomass (ethanol, methanol and ammonia), ammonia has the highest thermal efficiency and thus the greatest utilization of resources.

10.3 Energy Requirements for Transportation of Fuels

In moving the fuel to the conversion plant and to the consumer, a certain amount of energy is required. Table 10-10 summarizes the primary efficiency, and the fuel and electricity (ancillary energy) that would be needed to move the various fuels. The energy used for construction and maintenance is not included, but generally represents only about 10% of the ancillary energy shown. Also, any losses during distribution and storage are not included since these are generally essentially zero. In some cases, data were available from several different references, and the range is shown, as well as the value that will be used in this study.

In the case of pipelines for liquids, the energy required to move the product is very dependent on line size, viscosity of the product, heating value of the product, and flow rate. This accounts for part of the difference between the various references.

For a natural gas pipeline, the general practice is to use some of the gas as fuel, thus the energy consumption can be expressed as a primary energy efficiency. It is assumed that hydrogen would also be used as fuel if moved by pipeline.

The transmission and distribution of electricity have an average efficiency of around 0.91, based on national statistics.(10-7,10-8)

FIGURE 10-12

ENERGY ANALYSIS OF METHANOL PRODUCTION FROM BIOMASS VIA GASIFICATION

$$\text{Product Energy/Process Energy} = \frac{2.8}{0.67 + 0.12 + 0.46 + 0.1} = 2.07$$

$$\epsilon_1 = \frac{2.8}{8.51 + 0.67 + 0.46 + 0.12 + 0.1} = 0.28$$

Source: Adapted from Ref. 10-40

FIGURE 10-13

ENERGY ANALYSIS OF AMMONIA PRODUCTION FROM BIOMASS VIA GASIFICATION

$$\text{Product Energy/Process Energy} = \frac{4.41}{0.46 + 0.54 + 0.1} = 4.0$$

$$\epsilon_1 = \frac{4.41}{0.54 + 0.46 + 8.51 + 0.1} = 0.46$$

TABLE 10-10

SUMMARY OF TRANSPORTATION ENERGY
REQUIREMENTS FOR ALTERNATIVE FUELS

<u>Fuel</u>	<u>Primary Eff.</u>	<u>Fuel/Electricity Required to Move the Product BTU/10⁶ BTU Output</u>	<u>Reference</u>
<u>Coal</u>			
- Unit train	1.0	20 L(1) (Eastern Coal)*	10-7
		31 L (Western Coal)*	10-7
- Slurry pipeline	1.0	48 L (Western Coal)	10-7
- Barge	1.0	13 L (Eastern Coal)	10-7
- Train	1.0	30 L (Eastern Coal)	10-43
		45 L (Western Coal)	10-43
- Train	1.0	20 L	10-8
Crude Pipeline	1.0	48 L*	10-7
		16XL (36"φ-High Flow Rate)	10-43
		46XL (18"φ-High Flow Rate)	10-43
Petroleum Pipeline (also coal or shale liquids)	1.0	15 L*	10-7
		4 L	10-8
		4 L (25"φ-High Flow)	10-43
		23 L (12"φ-High Flow)	
Methanol Pipeline	1	30 L*	10-7
Methane	$1-3.6 \times 10^{-5}L^*$	-	10-7
Hydrogen (gas)	$1-5.2 \times 10^{-5}L^*$	-	10-7
Electricity transmission and distribution	0.91*	-	10-7
	0.92	-	10-8

* Value used in this study.

L = transport distance in miles.

(1) 20 times the transport distance in miles.

10.4 Total Resource Requirements for Various Alternate Fuels

Having established the thermal efficiencies for manufacture of the various alternate fuels and the energy required to transport the resources and finished products, it is now possible to estimate the total resources that would be required to provide the same amount of energy for each of the fuels that could be produced from coal or shale oil.

Figure 10-14 shows the total resources required to produce distillate from shale oil. Two types of energy are represented--the amount of shale resource required and the ancillary (fuels and electricity) energy used to transport the fuels. The ancillary energy may likely come from a different resource base, such as crude oil, but is included in the total for completeness. In most cases, it represents less than 2-3% of the total energy required.

As shown in Figure 10-14, it takes 1.59×10^6 BTU of shale to provide 1×10^6 BTU of energy in the form of distillate in the customers' tanks. In addition, 0.04×10^6 BTU of fuels and electricity would be required to move the syncrude to a refinery, the products to terminal storage, and then to the customer tankage. The distances assumed are shown in the figure. These are rough approximations of average distances, and could vary considerably in an actual situation. The thermal efficiency assumed at each processing step is also shown in Figure 10-14.

Similar charts for the coal-based alternate fuels are shown in Figures 10-15 through 10-23. Table 10-11 summarizes the information from these figures. As shown in Table 10-11, the most efficient way to use coal would be to burn it directly, but this has some practical limitations. A coal/oil slurry is the next most efficient way, but it does require the use of a petroleum product. Longer range, the petroleum could be replaced with a coal or shale oil derived liquid. Coal distillate and liquid methane require the same total resources, around 1.9×10^6 BTU of coal to provide million BTU of energy to the customer. Liquid hydrogen and acetylene require the most resource to provide a million BTU of fuel.

FIGURE 10-14

SHALE OIL LIQUIDS PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

FIGURE 10-15COAL--TOTAL ENERGY UTILIZATION

Total Energy Required - 10⁶ BTU/10⁶ BTU Fuel

Coal --1.0

Ancillary--0.016 - 0.036

Total --1.016 - 1.036 x 10⁶ Btu/10⁶ Btu of Final Fuel

(1) Does not include any energy used in coal cleaning or loss of coal fines.

FIGURE 10-16

COAL/OIL SLURRY PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

FIGURE 10-17

COAL LIQUIDS PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

FIGURE 10-18

**METHANOL PRODUCTION (COAL),
TRANSPORTATION AND DISTRIBUTION SYSTEM**

Total Resources -
10⁶ BTU/10⁶ BTU Fuel

Coal	--1.92
Ancillary	--0.07
	<u>1.99</u>

FIGURE 10-19

**HYDROGEN PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM**

**Total Resources -
 10^6 BTU/ 10^6 BTU Fuel**

Coal --3.37

Ancillary--0.16

3.53

FIGURE 10-20

METHANE PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

Total Resources -
 10^6 BTU/ 10^6 BTU Fuel

Coal --1.85

Ancillary--0.03

1.88

FIGURE 10-21

AMMONIA PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM

Total Resources -
 10^6 BTU/ 10^6 BTU Fuel

Coal --2.1
 Ancillary--0.05

2.15

FIGURE 10-22

**ACETYLENE PRODUCTION,
TRANSPORTATION AND DISTRIBUTION SYSTEM**

- (1) Based on the ϵ_1 efficiency. The efficiency would be around 30-34% if the by-product gases were used in the process.

FIGURE 10-23ELECTRICITY PRODUCTION,
TRANSMISSION AND DISTRIBUTION*

Total Resources -
10⁶ BTU/10⁶ BTU Fuel

Coal --2.89

Ancillary--0.03

2.92

TABLE 10-11SUMMARY OF TOTAL RESOURCES REQUIREMENTS

	<u>BTU of Resource/BTU of Final Product</u>		
	<u>Direct Require- ment</u>	<u>Ancillary Fuel/Electricity</u>	<u>Total</u>
<u>Coal</u>			
For Direct Burning	1.0	.016-.036	1.02-1.04
Coal/Oil Slurry	0.31-Coal 0.82-Oil	0.01	1.14
Coal Distillate	1.82	.06	1.88
Methanol	1.92	.07	1.99
Hydrogen (liquid)	3.37	.16	3.53
Methane (liquid)	1.85	.03	1.88
Ammonia	2.1	.05	2.15
Acetylene	3.45	.10	3.55
Electricity	2.89	.03	2.92
<u>Shale</u>			
Shale Distillate	1.59	.04	1.63

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It is useful to note that if the same calculation were done on the gross heating value of the same diesel fuel, a lower efficiency would be obtained, thus:

	<u>Net Heat, Btu</u>	<u>Gross Heat, Btu</u>
1 lb of fuel	18,500	19,740
0.35 lb of fuel	6475	6909
One HPH	-----2544-----	
Work/heat input, %	39.3	36.8

Of course, these two figures have exactly the same meaning, they both reflect the fact that 0.35 lbs. of fuel was burned to produce the horsepower hour of work.

The efficiency on net BTU is greater than that on gross BTU by a factor 1.066. This factor is not the same for all fuels, it depends on the hydrogen content of the fuel.

From the point of view of final economics, it makes no difference which way the efficiency is expressed provided the price of the fuel is expressed in the same units.

Thus if the diesel fuel under consideration had a price of 6¢/lb. it could be quoted as:

\$3.24/million BTU net, or

\$3.04/million BTU gross

The cost of producing a horsepower would calculate to exactly the same result as long as the appropriate heat content for price were employed with the appropriate efficiency.

Thus, One HPH = 2544 BTU.

Cost of one HPH:

$$= \$3.24^{(1)} \times \frac{2544}{10^6} \times \frac{100}{39.3^{(1)}} = 2.1\text{¢}$$

$$\text{or} = \$3.04^{(2)} \times \frac{2544}{10^6} \times \frac{100}{37.0^{(2)}} = 2.1\text{¢}$$

$$\text{or} = 6\text{¢/lb} \times 0.35 \text{ lbs/HPH} = 2.1\text{¢}$$

(1) Expressions based on net heat content.

(2) Expressions based on gross heat content.

In the literature, efficiency is expressed in various ways. Thus, a boiler/steam turbine combination is often described as 35% efficient on gross heat input to the boiler.

Alternatively it may be expressed as having a heat rate of 7270 gross BTU per HPH or 9750 gross BTU per kWh.

In this section, the efficiency figure would be translated to 37%, efficiency for example, on net BTU if the fuel which had provided the data were a petroleum type. It could then be taken that the system would remain close to 37% efficiency on the net BTU content of any other fuel, because boiler efficiency varies very little from fuel to fuel when it is compared on a net BTU basis.

Data for diesel engines is frequently given in terms of fuel mass required to produce unit work, as explained in the examples above.

Data for gas turbines and for spark ignited engines is usually given in the literature directly in terms of net heat content, as it is for all prime movers in this section.

Therefore in drawing cost comparisons between various prime movers and candidate fuels the price of the fuel in terms of a million net BTU has been used in this report.

11.3 Thermal Efficiency of Various Prime Movers

In addressing the question, "what are the alternate fuels/energy sources for non-highway transportation?" it is perhaps useful to first list the possible prime movers in order of their currently accepted thermal efficiencies on conventional fuels. Next a series of alternate fuels for each prime mover is considered and separated into three groups:

1. those which are compatible with the prime mover as it exists;
2. those which seem capable of being made to work, after some modification;
3. those which appear to have such severe incompatibility that they cannot be considered for such service.

The list of prime movers in order of efficiency is approximately as follows:

<u>Engine</u>	<u>Thermal Efficiency, % of Net Heat Content of Fuel</u>
1. Fuel cell/D.C. electric motor	50 - 60
2. Diesel engine	35 - 40*
3. Stirling engine	30 - 40
4. Free piston engine	25 - 30
5. Boiler/steam turbine	25 - 35*
6. Spark ignited or pilot ignited Otto engine	22 - 34*
7. Gas turbine	25 - 32*

(Could go to 35 with inlet temperature 3000°F)

This tabulation of ranges has been made for plant size in the 5-50,000 HP range which is the range of most interest for non-highway transportation.

The four prime movers marked with asterisks(*) are those for which a large amount of practical experience is available, and their efficiencies are really not in doubt for any fuel which is compatible, or which can be made to be compatible by reasonable engine modification.

In Table 11-1, combinations of various fuels and prime movers have been listed to show the probable efficiency that would result. Where blanks exist in this table, it is felt from a review of the literature, that there is very little hope of effecting a match. For example, although pulverized coal has been demonstrated to run in gas turbine engines(11-3,11-4) and coal/oil slurry to run in diesel engines(11-5,11-6) the experimental work has shown major problems. However, in the case of slow speed diesel engines, these problems may be tolerated and deserve further consideration.

11.3.1 Diesel Engines

Clearly the diesel engine is favored among the time proven engines. In addition to having a high thermal efficiency at full load, it maintains its efficiency down through the part load and almost into the idle regime. (See Table 11-2). It is for these reasons that the diesel has come to dominate railroad and international marine propulsion. Furthermore, the proven performance of diesel engines accounts for the large amount of work which is in progress to make them work on all sorts of alternate fuels; tar sand distillates in Canada, coal derived distillates, alcohols, hydrogen, vegetable oils and even ammonia.

TABLE 11-1

EFFICIENCIES OF PRIME MOVERS WITH VARIOUS FUELS

Prime Movers Fuels	Boiler Steam Turbine	Stirling Engine	Closed Cycle Gas Turbine	Spark or Pilot Ignited Otto	Diesel	Diesel Fumigated	Gas Turbine Open Cycle	Fuel Cell/ Electric	Electric Motor	Free Piston
Coal/methanol slurry	25-35	30-40	25-30	--	--	--	--	--	--	--
Coal/oil slurry	25-35	30-40	25-30	--	--	--	--	--	--	--
Coal	25-35	30-40	25-30	--	--	--	--	--	--	--
SRC I	25-35	30-40	25-30							
Coal liquids	25-35	30-40	25-30	22-35	35-40	--	25-32	--	--	25-30
Shale liquids	25-35	30-40	25-30	22-34	35-40	--	25-32	--	--	25-30
Methanol	27-37	32-42	27-32	22-34	--	35-40	26.5-34	50-60	--	25-30
Hydrogen	25-35	30-40	25-30	25-40	35-40	--	25-36	50-60	--	--
Carbon monoxide	25-35	30-40	25-30	22-34	--	--	25-30	--	--	--
Ammonia	25-35	30-40	25-30	22-34	--	35-40	25-32	--	--	--
Ethanol	26-35	31-41	26-31	22-34	--	35-40	26-33	--	--	25-30
Methane	25-35	30-40	25-30	22-34	--	35-40	25-32	--	--	--
Hydrazine	25-35	30-40	25-30	--	--	--	25-32	50-60	--	--
Methylamine	25-35	30-40	25-30	--	--	--	25-32	--	--	--
Acetylene	25-35	30-40	25-30	--	--	--	25-32	--	--	--
Vegetable oil	25-35	30-40	25-30	--	35-40	--	25-32	--	--	25-30
Electricity	27-38 ⁽⁴⁾	33-44 ⁽⁴⁾	27-33 ⁽⁴⁾	--	--	--	--	--	95	--

- Notes (1) Methanol and ethanol have been credited with higher efficiencies than other fuels in those situations where waste heat can be used regeneratively to overcome their high latent heat of vaporization.
- (2) Although coal derived liquid fuels are shown in general as having application to both Otto and Diesel cycle engines, the Otto required good octane properties whatever size the engine may be and the Diesel, good cetane at least in the smaller engines.
- (3) The free piston engine is thought to be much less sensitive to the chemical nature of the fuel, than the engines in Note (2).
- (4) Although electricity has been included as a possible boiler fuel in this table, it would of course be better used with an electric motor.

TABLE 11-2

EXAMPLE OF A TYPICAL DAILY
EMD SD-40 DIESEL LOCOMOTIVE UNIT OPERATION

(1)	(2)	(3)	(4)	(5)	(6)	(7)
<u>Throttle Position</u>	<u>Delivered Horsepower</u>	<u>Operation (Hours)</u>	<u>Work Delivered (hp-h)</u>	<u>Fuel Rate (Gals/h)</u>	<u>Consumption (Gallons)</u>	<u>HPHs Obtained per Gallon</u>
8	3100	3.6	11160	168	605	18.4
7	2550	1.0	2550	146	146	17.5
6	2000	1.0	2000	108	108	18.5
5	1450	1.0	1450	79	79	18.4
4	950	1.0	950	57	57	16.7
3	500	1.0	500	41	41	12.2
2	200	1.0	200	25	25	8.0
1	58	1.2	70	7.5	9	7.8
idle	*	12.0	500	5.5	66	7.6
Dyn. Brake	*	1.2	240	25	30	--
Total	--	24.0	19620	--	1166	--

* From reference 11-7 with right-hand column added to show efficiency i.e. Column (4) divided by Column (6) efficiency is almost constant from full power to one third load.

A desire to make the diesel engine omniverous, and more particularly to make it compatible with coal derived liquids has been expressed by several of the marine diesel manufacturers.

The first property which indicates likely compatibility or incompatibility of a candidate fuel with the diesel engine is its combustion performance, indicated in part by its cetane rating. Distillate fuels from petroleum and even blends of petroleum residua are proven in service, and paraffinic fuels from shale sources and distillate fuel from coal by Fischer Tropsch synthesis will be compatible with the diesel engine.

11.3.2 Free Piston Engines

The free piston engine is a form of hybrid between the diesel and the gas turbine, which gives promise of thermal efficiency below the diesel itself, but a likelihood of greater flexibility toward the range of fuel candidates. It is not nearly so dependent upon good ignition quality of the fuel and it has been stated(11-8) that it can burn anything from gasoline to bunker fuel oil. Ash, and the metallic impurities which are expected to be found in such candidates as coal and shale derived liquids are tolerated by this prime mover, whereas they would not be tolerable without considerable modification in an open cycle gas turbine. Therefore, on grounds of thermal efficiency and an omniverous capability, the free piston engine may deserve further consideration. Its failure to compete on a large scale with straight diesel engines(11-9) has been largely due to its excessive maintenance requirements, a drawback which might be alleviated by further development, and which might be balanced by its ability to burn fuels which are not compatible with the diesel engine or the gas turbine.

11.3.3 Gas Turbine

To date, the gas turbine has lagged behind other prime movers in thermal efficiency, although it is clearly understood that its efficiency can be improved to the extent that turbine inlet temperatures can be raised, and the limit here is dependent upon the blade materials withstanding oxidation corrosion, erosion from particles in the gas stream, and possible corrosion from ash constituents in the fuel.

Gas turbines have provided invaluable service in many situations where thermal efficiency had to be made secondary to other considerations.

Thus:

1. For aircraft, because of the light weight per unit of power available.
2. For pipeline pumping, because of their low cost per horsepower, their reliability and sometimes because they need no cooling water.
3. For peak power generation, where low investment per kW is much more influential on the peak electricity price, than is the cost of fuel.

In the case of pipeline pumping, the efficiency of the gas turbine is frequently raised to 35% by regenerative heating of combustion air by the heat in exhaust gas, and studies have been made of the application of combined steam and gas turbine cycles which reach 40% efficiency. While the weight and complexity of either of these systems makes their use less attractive for the vehicles, aircraft, railroads and ships, they are practically for pipelines, and become more and more economically viable if fuel costs escalate more rapidly than capital costs.

Nonetheless, the gas turbine is more limited than the diesel, the free piston, or a boiler/steam turbine combination in its ability to accept poor grade fuels. With fuel washing (to remove sodium) and with inhibition of vanadium by magnesium additives(11-10), a gas turbine can be run on bunker fuel oil with 10% reduction in power output and a small reduction in thermal efficiency of about 3% relative to operation on conventional, low ash distillate fuel.

The gas turbine is thus an engine which is capable of higher efficiencies with cleaner fuels. A wealth of experience exists with methane (natural gas), and with methane the upper limit of 32% quoted in the table can be obtained on large machines (about 100,000 HP) with inlet temperatures around 2000°F (1100°C). Indications are that liquid hydrogen and the alcohols (particularly methanol) could give higher efficiencies. For example an increase of 2% in thermal efficiency and 6% of power was obtained with methanol(11-11).

In the case of aircraft, the gas turbine is the only prime mover under consideration by any of the workers in the field; even when nuclear energy is considered as the source of heat for the engine. The concept of efficiency for aircraft goes beyond that of comparing shaft horsepower obtained with net heat of combustion supplied.

Among these possibilities, the effect of fuel type on efficiency is a combination of engine efficiency (related to turbine inlet temperature), relative mass of fuel which has to be carried for the mission, and the effects on drag and lift which are associated with the shape, size and disposition of fuel storage tanks. The type of mission, whether it be long or short, whether subsonic or supersonic affects the ranking of candidate fuels under discussion, i.e. which one accomplishes the mission with least expenditure of heating value (net BTU) in fuel. Two references indicate the following comparisons.

<u>Reference</u>	<u>Relative Consumption of Net Heat of Combustion For Same Missions</u>		
	<u>Jet Fuel</u>	<u>Liquid Methane</u>	<u>Liquid Hydrogen</u>
(11-12, p. 82, subsonic)	1.15	1.22	1.01
(11-13, subsonic)	1.12	--	1.00
(11-13, supersonic)	1.38	--	1.00

It should be noted that engine efficiency itself as given in the reference(11-12) was essentially the same for all three fuels 11,650 to 11,850 net BTU per hour per pound of thrust, with turbine inlet temperatures at 2500°F (1370°C).

Thus, the efficiency associated with the hydrogen fuel was not associated with the thermodynamic cycle, but was due to a reduction in necessary thrust with the lighter, more energy intensive fuel.

These comparisons relate to the actual net heat content of the fuels at point of receipt at the aircraft.

11.3.4 Spark or Pilot Ignited Engines

Apart from small aircraft and boats, spark ignited engines have had very little application in non-highway transport systems, the exception being certain pipeline applications where natural gas has been used in engines with high compression ratio. Figures given in a comparative study between electric motors and gas engines(11-14) indicate an efficiency of 34% for the latter which is about the limit that can be expected, and requires that the fuel have a high octane number. Candidate alternate fuels would therefore include hydrogen and the alcohols. The size range of these engines is generally less than 1000 HP. A marginal improvement above 34% efficiency can be anticipated if hydrogen or methanol comes into service in spark ignited engines. However, to derive the special thermal efficiency which is available from hydrogen at very lean mixtures would entail using a large engine and derating it to about 60% of its rated power. For a stationary application like pipeline pumping, this would not necessarily be an uneconomical approach; it would be necessary that the extra capital expense of the derated engine be recovered by the fuel savings obtained by burning hydrogen in the lean mixture region. The pooled results of many workers suggests that an efficiency of 40% for hydrogen could be obtained(11-15)

Thus, in an economic comparison of methane and hydrogen in spark ignited or pilot ignited Otto engines, the principal considerations would be these.

	<u>CH₄</u>	<u>H₂</u>
Size of engine to produce 1000 HP	1000 HP	1670 HP
Thermal efficiency at 1000 HP output	34% (rich mixture)	40% (lean mixture)
Thermal efficiency at 1670 HP output	--	34% (rich) but problems of backfire and knock would have to be controlled

To explain this further, it will be noted that the larger engine 1670 HP will cost more in capital and possibly in maintenance. As compensation, it will produce 1000 HP of work on less net BTU of hydrogen. At the reduced output, the hydrogen will be 40% efficient, using a lean mixture. Hydrogen has this advantage over methane because it ignites well at lean mixtures whereas methane does not. Methane has to be run at a fairly rich mixture, which gives all the power the engine was built to produce, but only at 34% efficiency. If hydrogen were run at a rich mixture, it too would give full power but its efficiency would drop to 34% and, more importantly, there would be problems of backfire and knock to be overcome, problems which do not arise if the hydrogen is used lean in the oversized engine.

11.3.5 Externally Fired Engines

The efficiency of engines like steam turbines, Stirling engines and closed cycle gas turbines, for which the fuel is burned externally, is a function of three things:

1. The efficiency of the combustion equipment, (boiler in the case of a steam turbine, heat exchanger in the case of the Stirling engine or the closed cycle gas turbine).
2. The temperature range through which the working fluid (steam, hydrogen, helium, etc.) operates. Thus a steam turbine which can accept steam at 1000°F and which voids it to a condenser at 80°F, can extract more work from the steam than one which accepts steam at 650°F and voids it to a condenser at 140°F.

For the two cases quoted the amount of work available from the working fluid would be in the ratio 1.4:1.0, purely a function of the enthalpy differences between the two high and the two low temperature levels.

3. The efficiency of the turbine or engine which accepts the working fluid at high temperature and rejects it at low temperature. For a large steam turbine the figure would be close to 80%. Taking the following component efficiencies as examples, the overall efficiency can be obtained.

	<u>Efficiency</u>
1. Boiler	90% on net heat of fuel
2. Steam cycle efficiency	58% available work in steam
3. Steam turbine efficiency	80% conversion of available work to actual work

Total product of (1) (2) and (3)

$$= 0.9 \times 0.58 \times 0.8 = 0.42, \text{ i.e. } 42\%.$$

While this figure can be approached in the best large power generating steam plants, it is difficult to obtain on the smaller scale because smaller turbines are less than 80% efficient and the steam cycles which have been available in practice aboard ships and in smaller stationary applications have not presented as much available work to the engine as is shown in this figure of 58% above. In addition, as discussed earlier, boiler efficiencies can vary between fuels based on differences between HHV and LHV. Also, the efficiency is a function of boiler size.

Accordingly, efficiencies in the range 25-30% have been more common for such smaller steam plant, which accounts for Specht(11-9) placing the efficiency of a free piston installation 27%, as "comparable to that of a modern steam turbine installation in the same power range." The date of the reference is 1962 and the power rating under discussion was 5000 horsepower.

However, the routes whereby such a steam plant could be improved are completely understood and depend essentially on increasing the steam conditions toward higher temperature and pressure, using lower pressure condensers and improved turbines.

The fuel for all externally fired cycles affects only the first component efficiency, namely that of the boiler which has been given as 90% in the discussion above. It should be noted again, that the figure is based on the net heating value of the fuel. It is common to find in the literature ranges of boiler efficiency from as low as 65% for a low BTU wet fuel like urban waste, bark or bagasse, up to 87% for a low hydrogen fuel like coal. This is largely because of the convention which has prevailed in U.S.A. of rating boilers on gross heat of combustion. Once the rating and the economic comparisons are made on net heat of combustion, most of these differences disappear and it can be said with reasonable accuracy that any fuel among the candidates discussed in this report can be burned in equipment (be it a boiler or other type of heat exchanger) with reasonable expectation of recovering 90% of the net heat of combustion into a working fluid.

From this point of view, the steam cycles, Stirling engine and closed cycle gas turbine may be considered as omniverous, and only slightly affected as far as efficiency goes, by the quality of fuel used.

Such engines offer the possibility of using coal, coal-oil slurry, coal-water slurry and solid wastes directly. Other engines, the diesel and gas turbine for example perform poorly, if at all, on solid fuels and require in general that the solid fuel be converted first into a liquid or gas.

Thus, engines which are externally fired and which convert solid fuel to work in one step, may be more efficient overall than engines which require intermediate conversion of the solid fuel. As an example, three possible routes for the production of work from coal are given below.

<u>Primary Fuel Coal</u>	<u>Secondary Fuel (Recovery Efficiency)</u>	<u>Engine (Efficiency)</u>	<u>Total Combined Efficiency</u>
100%	Coal (100%)	Steam turbine (30%)	30%
100%	Synthetic diesel (55%) fuel	Diesel engine (40%)	22%
100%	Synthetic methane (g) (66%)	Gas turbine (30%)	20%

The three engines presented in this example are all well tried and well developed. Their thermodynamic limitations are known, as are the routes which might be taken toward their improvement.

The Stirling engine is untried in any of today's applications for non-highway transportation. The closed cycle gas turbine (CCGT) has been employed to date mostly in district heating operations where electric power and waste heat are used concurrently. The appeal of both the Stirling and the CCGT is that they may be capable of higher thermal efficiency than the steam cycle, in the size ranges required for non-highway transportation.

Indications are that the following range of efficiencies might be expected.

Steam Turbine	25-35
Stirling	30-40
Closed Cycle GT	25-30

11.3.6 Fuel Cell/Electric Motor

The last class of engine to be considered is the combination fuel cell and electric motor, which lends itself particularly to a direct current electric drive. There is no doubt that a high thermal efficiency is available from fuel cells. Furthermore, that efficiency is maintained at all loads, and may even be better at part load than at full load. These are factors which could fit in well with railroad requirements, where in a typical day the engine runs at and above 80% of full power for five hours, and averages 40% of full power for another five hours (see Table 11-2).

The diesel engine/electric generator/DC motor has been proven very effective in railroad service, so in several ways its replacement by a fuel cell/DC motor would be a natural switch. However, in the case of fuel cells, fuel candidates are limited at least for the near and medium term to hydrogen, to fuels like hydrazine which can serve as a ready source of hydrogen, and to methanol.

Reference⁽¹¹⁻¹⁷⁾ indicates that fuel cells are much heavier than internal combustion engines producing equal power.

	<u>kg/kW</u>
Low temperature H ₂ /air	20
H ₂ /air solid electrolyte	10 - 15
Low temperature methanol	30 - 45
Internal Combustion Engine	3 - 4

11.4 Fuel/Engine Incompatibilities - Diesel Engine

Obviously there are fuels, which because they do not have the desirable properties are incompatible with the diesel engine. There are at least three levels of incompatibility.

1. The fuel may not ignite. An example of this is hydrogen, which would require a compression ratio of 80:1 to induce self ignition, whereas the limit of practical design does not exceed 20:1 or perhaps 24:1(11-17).
2. The fuel may ignite, but after such a delay that the conversion of heat to work cannot be optimized, and engine damage may result. Examples would be fuels of poor "cetane quality" such as gasoline, alcohols and highly aromatic liquid fuels.
3. The fuel may ignite, but take so long to burn that its heat content is either not totally released (unburned fuel in the exhaust gas) or, if released, released too late to be converted to work in an efficient manner(11-6).

An example is pulverized coal, which has been used to replace part of the conventional diesel fuel oil, but at a rate of replacement of about 4 pounds of coal per pound of oil replaced, which is indicative of an efficiency about 15% on coal compared with 40% on oil.

There are many cases in the literature in which a modification to the engine can result in a fuel becoming acceptable. Thus hydrogen and ammonia, which do not self-ignite in the diesel cycle can be fired at the right moment if a glow plug or similar source of ignition is provided. Having done that, a thermal efficiency is obtained which is very close to that obtained in an unmodified engine with its conventional fuel.

In the case of the alcohols several approaches have been explored.

1. The first is to modify the engine so that the alcohol is inducted with the air, is compressed in vapor form together with the air and ignited at the appropriate time by the injection of a reduced amount of regular diesel fuel oil.

This process is often referred to as fumigation⁽¹¹⁻¹⁸⁾ and has been employed with propane.

2. Another is to modify the fuel, in this case alcohol, by the inclusion of a large dose of "ignition improver." Specifically in the case of ethanol, a dose rate of about nine percent by volume of amyl nitrate or hexyl nitrate has been recommended to the government of Brazil as a means of using ethanol more efficiently within the Brazilian transportation sector⁽¹¹⁻²⁾.
3. A third is to provide separate injection of liquid methanol after injection of the pilot fuel, which is conventional diesel fuel oil⁽¹¹⁻¹⁸⁾.

The point to note is that having made one of these modifications, the fuel becomes usable, and the thermal efficiency which results is again close to that of the conventional engine running on its more conventional fuel.

It was said at the beginning of this section that the efficiency of a prime mover is much more a function of its design and operating conditions than of the particular fuel which is used. This does not imply that all engines can use all available fuels, indeed many are forbidden on grounds of incompatibility. But, to a reasonable approximation it appears that if a successful modification can be made to overcome the property wherein the incompatibility lies, the resulting thermal efficiency will be neither greatly enhanced, nor greatly diminished.

11.5 Fuel Properties that Enhance Efficiency

Certain fuels have properties which permit modifications to conventional engines which do enhance thermal efficiency. These are properties which the conventional fuel does not have. Thus, the range of flammability of hydrogen in air mixtures is so much wider than that of gasoline, that it can be run in an unthrottled spark ignited engine with a very lean mixture. Relative to gasoline, such operation brings three improvements in efficiency:⁽¹¹⁻¹⁹⁾

- The "pumping loss" associated with throttled engines is avoided. Pumping loss is the work that has to be done in abstracting mixture from a partial vacuum at the intake manifold and delivering its combustion products to the exhaust at atmospheric pressure.
- The rapid combustion of hydrogen permits the heat to be released predominantly close to the top dead center position of the piston, which brings maximum conversion of heat to work.
- The chemical nature of the combustion gases from a lean hydrogen mixture has specific heat properties which further improve the thermodynamic cycle.

Liquid hydrogen can also act as an efficient heat sink, that is a source of refrigeration. This property has been used to cool engine parts which are vulnerable at high temperature, and which if not cooled would impose a lower thermal efficiency ceiling on the engine. In the specific case of a gas turbine, the thermal efficiency is limited by the turbine inlet temperature, which is itself governed to avoid destruction of the first row nozzle and buckets. These elements, when cooled by internal passage of air can withstand higher inlet temperatures, and thus provide better thermal efficiency.

Liquid hydrogen has been used to supercool the air which in turn cools these blade elements, such that an efficiency was obtained which was significantly above that which was available with fuels that did not have this refrigerating capability(11-20).

To a lesser extent, the alcohols, methanol and ethanol, exhibit some of these special properties of hydrogen, i.e. ability to operate at leaner limits than gasoline in spark ignited engines and ability to absorb heat by virtue of their relatively high latent heats of vaporization.

The literature contains numerous references to the advantageous ways in which these properties can be utilized either to obtain more power from a specific engine, or a greater thermal efficiency.

The thermal efficiency of any engine which uses liquid methanol as fuel can be increased if waste engine heat is available to convert the methanol to the gaseous state(11-21).

<u>Methanol</u>	
(a) Net heat of combustion (liquid fuel/water vapor)	8570 Btu/lb
(b) Latent heat of vaporization	506 Btu/lb
(c) Net heat of combustion (vaporized fuel/water vapor)	9076 Btu/lb
(d) Increase in energy (c) ÷ (a)	1.06

A corresponding table for ethanol and for jet fuel follows.

	<u>Btu/lb</u>	
	<u>Ethanol</u>	<u>Jet Fuel</u>
(a) Net heat of combustion (liquid fuel/water vapor)	11 500	18 500
(b) Latent heat of vaporization	396	150
(c) Net heat of combustion (vaporized fuel/water vapor)	11 896	18 650
(d) Increase in energy (c) ÷ (a)	1.03	1.01

It will be noted that six percent more heating power is available from a unit of methanol once the latent heat of vaporization has been supplied, and since this can practically always be supplied freely from waste engine heat, methanol can be credited with a proportional advantage relative to conventional fuels like diesel fuel oil or jet fuel which do not have a comparable latent heat, and which cannot be vaporized so cleanly. On similar grounds, ethanol has a three percent potential and jet fuel about one percent.

Going one step further, it has been suggested that a further six percent improvement in the use of methanol as fuel would accrue if waste heat were employed to split the fuel into H_2 and CO over a catalyst at low pressure. Ethanol and methanol leave very little residue upon evaporation, and produce no coking, therefore, they are expected to perform well in engines which utilize waste heat to gain the latent heat bonus. However, the technique is not completely proven for long-term operation, so some development work may be needed relative to the design and maintenance of the heat exchange equipment wherein the evaporation occurs. Jet fuel and other petroleum products would be expected to foul evaporative heat exchangers, and the very small benefit of latent heat recovery with those fuels would not be practical nor worthwhile.

It should be noted that while the special properties of H_2 and the alcohols permit design changes which improve the efficiency of certain engines, these improvements have to be bought with certain tradeoffs. Hydrogen, while operating most efficiently at very lean conditions in a spark ignited engine, produces only half the power for which the engine is rated on gasoline.

In the case of alcohol use with diesel engines(11-18), the design, and more particularly the control of the dual fuel handling system, becomes extremely complicated, especially if it is desired to approach a fifty percent replacement of the conventional fuel by the alcohol over the total operating range of the engine.

Because of this apparent complexity, several workers recommend that a better approach toward the use of methanol would be the use of a spark ignited Otto cycle engine, with high compression ratio.

11.6 Combined Cycles

Various combinations of cycles can be used with several of the prime movers to obtain an overall efficiency higher than that of the engine itself when operated in the conventional way(11-22). Essentially, these combinations seek to convert waste heat from the conventional engine into a further supply of work at no increase in fuel rate. The subsidiary engines most often considered are steam turbines and organic Rankine engines. In these cases the working fluid for the subsidiary engine is heated in a waste heat boiler by exhaust gas, or in some cases by the heat in high temperature cooling water.

Ackerman (11-23) provides data on efficiencies that can be expected of gas turbines fired on hydrogen, with and without a combined steam cycle. The steam can be made available at about 900°F from heat in the GT exhaust.

<u>Inlet Temperature, °F</u>	<u>Thermal Efficiency, %</u>	
	<u>Gas Turbine</u>	<u>Combined Cycle (steam turbine added)</u>
2000	30	--
2300	34	42
3000	35.5	46

Organic Rankine cycle engines (ORC) may find application where waste heat is available at temperatures lower than those of the gas turbine exhaust. Diesel engines and closed cycle gas turbines may lend themselves to combination with ORC with an expectation of recovering about 13% of the waste heat as work.

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12. FUEL LOGISTICS

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This section will discuss three different aspects of the logistics of alternative energy sources:

- (1) compatibility of alternative energy resources with present fuels and with the current fuel distribution system
- (2) international and military considerations
- (3) resource availability

Item number two is considered in more detail in Section 16. Each, however, has the potential for imposing important practical constraints on the development of fuels that differ radically from those already in use. The principal purpose of the present discussion is to indicate the essential characteristics of the compatibility, international, and military considerations and the types of constraint that may be inferred from these characteristics. This information will serve as background for the detailed discussion of items three on resource availability.

12.1 Compatibility with Present Fuels and the Current Distribution System

For the purposes of this discussion an incompatible (alternative) fuel is considered to be one that cannot be used effectively in the existing equipment of a particular non-highway transportation mode. The latter is a system of use that comprises fuels, the distribution of the fuels, and the eventual use of the fuels in NH equipment. Incompatibility of a new (alternative) fuel with any of the elements of the system of use would require the new fuel to be considered incompatible. This does not mean that the new fuel should be eliminated from further consideration in this study. Rather, it implies that introduction of the new fuel would be more difficult and costly than the introduction of a compatible (alternative) fuel. It is also probable that these difficulties and costs would be institutional as well as technological.

A second point concerns the relationship between highway (HT) and non-highway (NHT) transportation systems. For example, each of the NHT modes may be considered as a subsystem, but the aggregate of NHT modes is not a system. From a fuel standpoint, there may be a greater similarity between individual HT and NHT subsystems than there is among the different NHT modes. Air and marine modes use significantly different fuels. On the other hand, railroad diesel fuels are quite similar to the automotive diesel fuels used by trucks; hence the availability of, and demand for, the one type of fuel may act as a constraint on the other type of fuel. In fact, the two types of fuel are similar and it is primarily their end-use that differs.

A third point is that current fuels*, for both HT and NHT systems, are part of the overall system of utilizing petroleum. For example, the consumption of middle distillate as heating oil far exceeds consumption as diesel fuel. Similarly, the demand for "land trade" industrial fuel far exceeds the demand for marine bunker fuel. The significance of the fungibility of petroleum fuels across transportation and non-transportation end-uses makes it unrealistic to consider fuels for NHT systems in isolation. This is because a change anywhere in the total system of utilization of petroleum (and other energy sources) may have an impact on other parts of the system. This is a problem of immense difficulty and complexity, and its resolution is beyond the scope of this study. However, the interrelationships are illustrated in the cross-impact analysis segment of Section 18.

12.2 International and Military Considerations

International considerations may be divided into (a) fuels and (b) equipment. Clearly, both air and marine operations may involve international fueling. Hence, any new fuel, especially an "incompatible" fuel, should be available wherever it is needed, including foreign locations that are part of the international system.

Equipment considerations and constraints are more complex than those that apply to new fuels. The U.S. is a major exporter of equipment for NHT systems: aircraft, locomotives, construction equipment, farm vehicles, etc. Hence, U.S. manufacturers of such equipment must be mindful of the difficulties, costs, and risks they would experience if they were to develop incompatibly different equipment for the U.S. and their export markets, especially if the different equipment were to create an associated demand for incompatibly different fuels.

For some years, the Department of Defense has been interested in the development and testing of "synthetic" fuels from coal, oil shale, and tar sands. The focus of DOD's work has been on the production of fuels that meet the specifications of current petroleum fuels**. Fuel compatibility and availability are of obvious importance, and require consideration in relation to NATO and other overseas defense responsibilities.

12.3 Resource Availability

It is of paramount importance to consider that the fuel demand of non-highway transportation systems is only one of a multitude of demands placed on U.S. resources, hence neither the magnitude of the resource base of a given resource, nor the physical availability of fuels or usable energy derived from the resource, guarantees availability of the fuels or energy to NHT systems.

*with minor exceptions.

**A limited amount of effort has also been applied to coal-in-oil slurries (COS) for marine applications.

The conceptual problem is illustrated in Figure 12-1. In the center of the diagram, there is a "box" with dashed lines that enclose the words "future 'pool' of fuels and energy supplies derived from all resources." The concepts are that at any time in the future:

- this "pool" is the total available supply of all fuels and forms of energy derived from all resources.
- the "pool" must be divided among all of the various demands for fuels and energy, i.e. there will be competing demands for what is in the "pool".
- if the sum of the various demands exceeds the supplies available in the "pool", then end-uses will be constrained (i.e. a supply shortage will exist, temporarily at least).
- there is no reason, a priori, why one end-use will have priority over another; instead the establishment of priorities will involve complex interactions between sociopolitical and economic factors. Specifically, fuels for NHT systems cannot be considered, a priori, to have a higher priority than other end-use demands.

The conceptual problem is explained further by reference to a given resource, e.g. oil shale, which is identified as Resource "X" in Figure 12-1. The resource base of "X" has been estimated to be very large (in the case of oil shale). The current utilization of "X" is minimal, hence HT and NHT utilization of fuels derived from "X" is minimal. However, because of the size of the resource base, the future production or availability of fuels derived from "X" is potentially high. At this point, the potential contribution of "X" to the nation's "pool" of fuel and energy supplies should be allocated (conceptually) to the "pool" rather than be pre-empted, a priori, for use by NHT systems. Put differently, fuels and energy for NHT systems are not coupled directly with Resource "X", rather they are coupled indirectly through a supply "pool" which must satisfy the totality of competing end-uses.

The premise that underlies the development of "alternative fuels" is an anticipation that the future supply "pool" may be inadequate to meet future demands in an unconstrained way. The anticipation of constraints is also an anticipation that mechanisms will evolve (or will have to be devised) to deal with end-use priorities, presumably in terms of some "sharing" of the supplies that are available. The mechanisms may be both technological and non-technological. An example of the former is that technical paths will be devised for maximizing the effectiveness of utilization of the supply "pool" in relation to the various end-use demands placed on it.* Non-technological mechanisms are potentially quite diverse since, theoretically, they include institutional constraints, differential taxation, rationing, etc. The non-technical mechanisms are considered in more detail in Section 17; for present purposes, however, the point is to recognize the

*For example, it may be more economical to upgrade some conventional fuels to more sophisticated end-uses and to substitute an alternative fuel in the end-use from which the conventional fuel is displaced.

FIGURE 12-1

COMPETITIVE ASPECT OF RESOURCE AVAILABILITY

probability of their existence and importance and, hence, the difficulty or impossibility of establishing direct, quantitative linkages between potential resources and future supplies of individual fuels or energy forms that, technologically, could be used in NHT systems.

A further point may be made about the effective utilization of the supply "pool". Substitution of one fuel or energy form for another appears much easier in stationary applications (e.g. industrial boiler fuel, central generation of electricity) than in transportation uses. Primarily, this is because of the greater severity of constraints (e.g. weight, size, emission controls) that apply to mobile equipment. The same principle is applicable within the various NHT modes. For example, constraints of weight and volume are more severe for aircraft than they are for ships. Additionally, however, there are logistical constraints that apply to certain resources. For example, wood and wood by-products are already used extensively to generate both steam and electricity by the pulp and paper industry. Indeed, this industry is moving rapidly toward self-sufficiency in satisfying its own energy demands. Hence, the biomass utilized captively by the pulp and paper industry is not available for conversion into fuels for NHT systems. In general, it is believed that substitution of resources across a variety of end-uses, particularly in stationary applications, will have a profound impact on the components of the supply "pool" that, in practice, become available to NHT systems. For example, the displacement of oil from electricity generation has the potential for making oil available for transportation uses.

Conceptual objections may be raised to the substitution hypothesis. For example, petroleum is a finite resource, and this fact will not be altered even if no oil is used to generate electricity. On the other hand, such displacement may have important impacts on (a) the timetable of reliance on renewable resources, and (b) the evolutionary paths towards such reliance.

12.3.1 Primary Energy Resources

The principal primary energy resources, except for petroleum (crude oil and natural gas) are listed in the first column of Table 12.1. The next column provides a qualitative characterization of the size of the resource base of each of the primary resources. These characterizations require explanation:

- very large implies that the resource base, per se, is not expected to be a limiting factor within the next 100 years.
- large implies that considerable further development of the resource appears possible, but that limitations to development are expected within about 50 years. In the case of nuclear energy, the reference is to reserves of fissile materials in the U.S., and does not take account of (a) imports of uranium, etc., (b) the possibility that nuclear fusion technology will become the commercial basis of electricity generation within the next 50 years, or (c) that breeder technology will be utilized commercially in the U.S. to greatly extend the naturally occurring resources of fissile materials.*

*The practical improbability of the combination of these three assumptions is recognized. However, the assumptions are believed to be proper in the context of the above comparison of the U.S. resource base.

- medium has two different implications: (a) in the case of geothermal steam that, while considerable development is possible, the ultimate potential is much smaller than for resources categorized as large or very large, and (b) in the case of hydroelectricity, while current utilization of the resource is significant, it is approaching maturity and, hence, does not represent a significant incremental resource by comparison with those categorized as large or very large.
- "other" implies that there are resources such as wind or tidal power that, currently, are not well defined in extent. Moreover, it appears that, if developed, such resources will be utilized on a local basis and, hence, are unlikely to make significant, direct contributions to the supply of transportation fuels. While electrical production of hydrogen is a possible exception to this generalization, the possibility is too indefinite to warrant a resource base rating of more than "medium".

Availability, as characterized in the third and fourth columns of Table 12-1, also requires explanation:

- high implies that the resource currently supplies, or has the future potential for supplying, at least 15% of U.S. primary energy demand.
- medium implies that the resource currently supplies, or has the future potential for supplying, about 5% of U.S. primary energy demand*
- small implies that current supply or future potential is or will be at about a 1% level
- negligible refers only to current level of energy supplied; it does not imply that the resource has no importance or that attempts to develop it further are misdirected

The column for "competing uses" implies that major competition for each of the resources exists now or is expected in the future. For reasons discussed earlier, the extent of this competition cannot be precisely quantified. However, "major" implies the belief that from 15% to 100% of the available resource may be utilized for end-uses other than NHT systems.

The final columns of Table 12-1 list representative alternative fuel products or intermediates derivable from the primary energy resources. The term "intermediate" refers to a stage of processing, e.g. a syncrude derived from shale oil is convertible into a variety of fuel and other products as is a petroleum crude oil. The distinction between products and intermediates is fuzzy because most of the products (e.g. methane, methanol, ethanol) are convertible into other products as well as being utilizable directly as fuels. There is a further ambiguity in the case of electricity which is utilizable directly as an energy source for certain types of ground transportation system as well as being utilizable indirectly in the production of fuels. Some of the special attributes of electricity are listed in Table 12-2.

*In 1978, it is anticipated that nuclear energy and hydro power will each supply about 4% of U.S. primary energy demand.

TABLE 12-1
RESOURCE AVAILABILITY

Primary Energy Resource	Size of U.S. Resource Base	Availability		Competing Uses**	Representative Intermediates or Alt. Fuels Derivable from Resource	
		Current	Future*			
Coal (1), (2), (3), (4)	very large	high	high	major	coal liquids methanol [ethanol] hydrazine methylamine	hydrogen methane ammonia acetylene slurries
Oil Shale (5), (6)	very large	negligible	high	major	raw shale oil shale syncrude ^φ	
Peat (7)	very large	negligible	small	major	peat liquids	methane
Biomass (8), (9), (10), (11), (12), (13), (14)	large	medium	medium	major	methanol ethanol other alcohols	methane veg. oils
Geothermal (steam) (5), (6)	medium	small	medium	major	electricity	
Solar (8)	large or very large	small	high	major	electricity	direct heat source
Nuclear (15), (16), (17), (18)	large	medium	high	major	electricity	direct heat source
Hydro (5), (6)	medium	medium	medium	major	electricity	
Other (6) (wind, tidal, etc.)	not well established, probably medium	negligible	small	major	electricity	mechanical energy for pumping

*future availability refers to potential, rather than implying a prediction of production level

**competing uses imply that the resource is being currently used for purposes other than the production of non-highway transportation fuels or that there is a probability of such competing uses in the future.

] implies an indirect synthesis route is required, thereby suggesting that ethanol production from coal is questionable.

^φ further processing of shale syncrude would generate a range of petroleum-type transportation fuels.

) denotes references, which are listed at end of section.

TABLE 12-2

ELECTRICITY AS A TRANSPORTATION ENERGY SOURCE

- Electricity is a source of transportation energy and may become a source of transportation fuels.
- Electricity is not a primary energy resource, but depends on other resources for its generation.
- Resources currently used to generate electricity are:
 - Major: fossil fuels, nuclear energy, hydro power
 - Minor: biomass (primarily wood and by-products), geothermal steam
- Additional resources that may be used to generate electricity in the future:
 - Major potential: oil shale, solar energy
 - Minor potential: wind power, tidal power
- Electricity may be applied directly as a source of power to ground transportation systems such as railroads and monorails.
- Electricity may be utilized as process energy in the production of fuels and hybrid energy systems involving batteries, fuel cells, hydrides, etc.
- Hydrogen is the only transportation fuel that may be produced directly with electrical energy without the need for any "feedstock" except water.

12.3.2 Documentation of Size of Primary Resource Base

The purpose of the following discussion is to support the characterizations of the resource base in Table 12-1:

- coal: the quantity extractible with current technology and under existing economic conditions (i.e. "reserves") is estimated to range from 218 to 259 billion tons. However, there is geologic evidence* of the existence of 1.7 trillion tons of coal and this is the estimate of "identified resources". Total U.S. resources of coal have been estimated to be about 4 trillion tons; this figure includes both hypothetical as well as identified resources.
- oil shale: identified resources of Western oil shales have been estimated to contain about 1.6 trillion barrels of oil. Oil shale deposits also occur in other parts of the U.S., e.g. in Michigan. While the potential recovery of oil from oil shale is very large, factors** other than the size of the resource base are likely to limit both the pace and extent of what is recovered.
- peat: the estimated resource base for peat is equivalent to about 60 billion tons of bituminous coal. Much of this quantity is potentially recoverable because peat generally occurs at the surface in beds*** shallow enough (averaging 7 feet) to permit restoration of the stripped land to its original contour. However, peat contains several times its own weight in water and must be dried to about 35% moisture before use as a fuel. For reasons of net energy and cost, drying must be simple, effective, and performable in environmentally acceptable ways. Gasification to SNG is being investigated; this approach would yield some hydrocarbon-type liquids (after hydrogenation) as a co-product.
- biomass: as discussed in Appendix 12A, the renewability of biomass necessitates a departure from the conventional concepts of "reserves" and "resources". In a sense, the "resource base" for biomass depends on the amount of land**** in the U.S. that is capable of growing plants after subtraction of land utilized or reserved for other purposes (e.g. residences, commercial buildings, industrial plants, roads, etc.). Existing forests are a form of "reserves". However, forests are regenerable over a period of years, hence the rate of extraction and the other resources needed to accomplish this extraction are more meaningful than an estimate of reserves or of the current resource base.
- solar: as with biomass there is no precise definition of a resource base for solar energy. Moreover, the production of biomass depends directly on the utilization of solar energy. However, for the purposes of Table 12-1, only the portion of solar energy used to generate electricity or heat is considered as "solar".

*not necessarily supported by engineering measurements.

**e.g. availability of water and environmental constraints.

***because of extremely high moisture content, the "beds" are bogs. Dewatering techniques are under investigation.

****there is also a potential for producing biomass by mariculture, e.g. off the west coast of California.

- nuclear: in the context of Table 12-1 and its footnotes, the resource base is confined to U.S. deposits of uranium ore. Approximately 780,000 tons of uranium has been estimated in the ore deposits that have been delineated by drilling. While it is clear that this is not the full extent of the resource, and it has been speculated that an additional 1.9 million tons of uranium may be recoverable, there is no consensus on the validity of this number or on how it should be interpreted. However, there is general agreement that shales and granites containing less than 100 ppm of uranium are most unlikely to become a source of uranium. Although the extent of the U.S. uranium resource is an extremely important matter in itself, it is even more important (for the purpose of this study) to recognize that the ways in which the resource is utilized will be the eventual determinant of the quantity of useful energy produced from nuclear materials.
- domestic tar sands: It is important to distinguish between Canadian (Athabasca and Wabasca) oil sand deposits -- which are very considerable -- and those in the U.S. -- which are not. The largest U.S. deposits are in Utah. It has been estimated that total production from these deposits could never exceed 500,000 B/D, and also that anything beyond token production is unlikely before the year 2000(12-19).

The Utah deposits are in areas that adjoin the principal oil shale lands. In consequence, exploitation of the Utah tar sands would compete for the same natural resources (e.g. water) that are required for the far more promising oil shale production. Hence, at most, conversion of U.S. tar sands into alternate fuels may be considered as a minor perturbation of what is possible with oil shale.

12.3.3 Logistics of the Principal Primary Energy Resources

The purposes of this subsection are to indicate that there are significant logistical differences among the various primary energy resources and to characterize these differences. The intent is not to make a detailed logistical analysis of the primary resources.

- coal: deposits are dispersed widely throughout much of the U.S., hence coal is potentially available in most locations. However, transportation costs can be a significant fraction of the delivered cost of coal. In general, this favors the utilization of coal as close as possible to the mine or, where this is not possible, delivery of very large volumes of coal by barge, unit train, or slurry pipeline.

- oil shale: the richer deposits of oil shale are concentrated in a small area, primarily in Colorado and Utah but with lower grade deposits extending into Wyoming. When consideration is given to the fact that one ton of oil shale will yield only about three quarters of a barrel of shale oil, it is evident that extraction of oil from shale must occur in a mine-mouth setting (whether by surface retorting or by an in-situ process). This suggests that shale oil will become part of the oil supply of a Western region of the U.S. Devonian shales exist in other parts of the U.S., e.g. Michigan, and may become a source of SNG.
- peat: slightly over half of the peat resource is in Alaska (31 billion TCE), where its early exploitation is unlikely and where dewatering and land reclamation would be more difficult than in the "Lower 48". However, there are about 16 billion TCE of peat resources in Minnesota, Michigan, and Wisconsin; SNG projects in these states may be feasible before the year 2000. The quantity of refined liquid co-products is unlikely to exceed 0.5 quads/yr. at this time or 1 quad/yr. at any time in the future. Thus, peat liquids, per se, are unlikely to be an "alternative fuel". Instead, the liquids could be a small supplement to the "pool" of supplies available for all purposes.
- biomass: this is a class of materials, rather than a uniform resource. Both forests and crops have regional patterns that are certain to influence the ways in which different "biomasses" are utilized. A common characteristic, to the land extensive production base (as distinct from the concentration of a fossil fuel resource in a given deposit), is that utilization of biomass is likely to be in relatively small plants as close as possible to the production area. Captive utilization of byproducts by industries that produce and/or use wood is commonplace and is increasing. Certain agricultural by-products, e.g. bagasse, fit the same pattern of captive utilization.
- solar: this source of energy is inherently dispersed, thereby favoring relatively small user installations. The most probable contributions of solar energy to NHT systems are indirect, e.g. by substituting for other forms of energy thereby relieving constraints on the total pool of energy supplies.
- nuclear: while nuclear energy is, and will probably continue to be, produced in large units or groups of units ("nuclear parks"), the plants themselves may be widely dispersed throughout the U.S. Nevertheless, severe logistical constraints may apply to the production of nuclear energy because of restrictions placed on the movement and disposal of nuclear wastes.

12.3.4 Discussion of Representative NHT Intermediates and Products

The principal primary energy resources*, electricity and its principal sources*, and representative propellents of NHT systems are presented in the form of a matrix in Table 12-3. The numbers and letters in the matrix reflect judgments concerning time-frame of availability and associated probability. Electrified railroad systems are omitted from this tabulation because (a) they already exist, and (b) their further development is not limited by primary resources but by economics.

An asterisk has been added to several of the entries in Table 12-3 to indicate the judgment that although the specific fuels may be available in a given time-frame, it is expected that they will be utilized in other end-uses rather than as NHT fuels. With one major exception, the electricity sources have been marked with an asterisk. The exception, nuclear energy, has been given a 3A rating -- possible by the year 2000 -- because it is possible that nuclear energy will have the practical capability both of generating electricity for conventional uses and of generating some hydrogen by the year 2000 -- even though a later time-frame seems more likely. The other electricity sources, with the exception of solar energy in a distant time-frame, are all conceived to contribute to electricity supplies in general rather than to become direct sources of transportation hydrogen. Looked at another way, the aggregate increment of electricity generated by minor sources is a "perturbation" of the amount of nuclear electricity available for the production of transportation hydrogen.

12.3.5 Fuel Logistics Criteria

Estimates made for fuel logistics criteria are listed in Table 12-4. The second and third columns reproduce the fuels and ratings from Table 12-3. The next two columns consider the compatibility of the possible alternative fuels with the fuels used in the current system and with the system itself. The final column is a preliminary indication of how the various fuels may be impacted by international considerations. The rating "variable" requires explanation. The premise is that certain other countries have substantial coal resources while most do not, and also that a few countries have oil shale resources while the majority do not. The associated concept is that countries not having the pertinent coal or oil shale resources would be unlikely to be willing to disrupt their fuel supply and transportation systems in order to accommodate U.S. technological development of the resources. However, no disruption would occur if the new fuels were completely compatible with existing fuels and transportation systems.

*excluding petroleum.

TABLE 12-3

MATRIX OF PRIMARY RESOURCES AND REPRESENTATIVE
PROPELLENTS OF NHT SYSTEMS WITH INDICATION OF
TIME-FRAME OF AVAILABILITY

	Coal	Oil Shale	Biomass	Electricity
raw liquids	2A*, 3B			
upgraded liquids	2A*, 3B			
methanol	2A, 3B			
ethanol	U			
hydrazine	U			
methylamine	U			
hydrogen	2A*, 3B*			
methane	2A, 3B			
ammonia	2A*, 3B*			
acetylene	U			
oil slurry	1A			
methanol slurry	2A, 3B			
raw shale oil		2B		
shale syncrude		2B		
methanol			2A*, 3B*	
ethanol			1	
other alcohols			∅	
methane			1B*	
vegetable oils			∅	
geothermal steam				1*
solar				2*, 4A-U
nuclear				1*, 3A
hydro				1*
other				1*-3*

Key: 1 = now or by 1980
2 = by 1990
3 = by 2000
4 = after 2000

A = possible
B = probable
U = unlikely or highly uncertain

*utilization for purposes other than NHT fuels seems probable in
pertinent time-frame.

∅ insignificant utilization as NHT fuels expected.

TABLE 12-4

FUEL LOGISTICS CRITERIA

Source	Derivative Fuel	Availability ^φ	Compatibility with Current		International Considerations
			Fuels	System	
Oil		high	no	no	variable
	raw liquids	2A*, 3B	some problems	some problems	generally unfavorable
	upgraded liquids	2A*, 3B	yes	yes	probably favorable
	methanol	2A, 3B	some problems	some problems	probably favorable
	ethanol	U	yes	yes	probably favorable
	hydrazine	U	no	no	unfavorable
	methylamine	U	no	no	unfavorable
	hydrogen	2A*, 3B*	no	no	uncertain
	methane	2A, 3B	some problems	some problems	probably favorable
	ammonia	2A*, 3B*	no	no	generally unfavorable
	acetylene	U	no	no	generally unfavorable
	oil slurry	1A	some problems	some problems	uncertain
	methanol slurry	2A, 3B	some problems	some problems	generally unfavorable
Oil Shale		high	no	no	variable, generally unfavorable
	raw shale oil	2B	some problems	some problems	generally unfavorable
	syncrude/products	2B	yes	yes	probably favorable
Biomass		medium	no	no	variable
	methanol	2A*, 3B*	some problems	some problems	probably favorable
	ethanol	1	yes	yes	probably favorable
	other alcohols	insignificant	-	-	-
	methane	1B*	some problems	some problems	probably favorable
	vegetable oils	insignificant	-	-	-

^φ ratings for individual products from Table 12-3

1 = now or by 1980

A = possible

2 = by 1990

B = probable

3 = by 2000

U = unlikely or highly uncertain

4 = after 2000

* = probable utilization for purposes other than NHT fuels

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APPENDIX 12A

Biomass Resource Availability

Biosolar or biological resources, unlike fossil fuels, are renewable. This is the strategic characteristic that makes biomass of such interest as a source of fuels in the future. In spite of the orientation to the future, certain forms of biomass have been conventional fuels for decades and even millenia, although use as transportation fuels has been limited to a few special situations. Renewability, however, is not the only characteristic that distinguishes biomass from commercial fuels such as oil, gas and coal. As discussed below, recognition of the distinguishing characteristics is important to quantitative assessment of the future fuel potential of biomass.

Terms such as "reserves" and "resources" may be applied to biomass but, when this is done, the meaning of the terms may be different than the customary meanings and definitions that have been developed for fossil fuels. Forests, for example, might be conceptualized as "reserves" of biomass. This conception, however, would be incomplete without consideration of matters such as:

- has the use of the forest already been designated or determined? (e.g. for timber, pulp and paper, recreation, natural watershed, etc.)
- if an extractive, but non-fuel use of the forest has been predetermined would there, nevertheless, be by-products of potential use as fuels associated with the primary extractive use?
- if utilization of fuel by-products is possible, is it also likely that such utilization would be captive to the primary extraction endeavor? (e.g. the use of bark and other wood wastes to supply the process energy needed for a pulp plant -- thereby preventing the utilization of the wastes for some non-captive purpose such as the production of transportation fuels)
- how should renewability be defined?
- if renewability were to be related to an average annual production rate, would this rate be limited by the production rate required for the primary endeavor?
- even though the biomass itself is renewable, would the process of renewal deplete another non-renewable resource? (e.g. phosphate fertilizer)
- would the process of renewal perturb the utilization of what are generally considered to be renewable resources such as water?
- what will be the future impacts of possible developments in the technology of producing biomass? (e.g. plant genetics, natural fixation of nitrogen)

Most, or all, of the above questions would become important in the event of attempts to utilize biomass for the production of transportation fuels on a large scale. The essential distinctions are:

- (1) the resource base of fossil fuels is fixed* and depletable
- (2) the resource base of biomass is variable, and is dependent on a large number of other variables.

Thus, the resource base of fossil fuels is essentially a "given" (even though we may not know its precise extent), while the resource base for biomass is essentially a "taken" (12-1) (i.e. depends on assumptions made about the contingent variables of a complex, dynamic, interactive system).

The foregoing discussion was intended to:

- make important conceptual distinctions between fossil fuels and biomass
- explain why precise quantification of future biomass resources should not be expected.

The infeasibility of precise quantification does not imply that no quantification at all is possible. Indeed, the open literature contains a variety of estimates, five of which are discussed briefly below. All of the estimates are contingent upon explicit or implicit assumptions, and should not be accepted without recognition and evaluation of these assumptions. Most of this evaluation will be undertaken later, but some background considerations are listed in Table 12A-1.

In a recent paper, (12-51) Lupinsky observes that "future needs of the United States for fuel are gigantic compared with the energy that biomass can deliver." He estimates that only 1% of U.S. energy consumption in 1976 (about 74 quads inclusive of non-energy requirements, i.e. feedstock consumption, of fossil fuels) could have been satisfied by 60% of the U.S. corn crop**. Other points made by Lipinsky are:

- "Both enzymatic hydrolysis and acid hydrolysis of lignocellulosic biomass appear to be decades from commercial utilization."
- "Both the biomass resources and the chemicals to be used as fuels . . . have alternative applications, such as chemical feedstocks, pulp for papermaking, human food, and animal feeds. The prospects for fuels from biomass are strongly affected by these alternative uses."

*except in the sense of geological time.

**the estimates are in terms of BTU equivalency and do not imply that three fifths of the corn crop could actually have satisfied 1% of U.S. energy needs.

TABLE 12A-1SOME BIOMASS CONSIDERATIONS

- (1) Wood used to be the principal source of fuel in the U.S. For many years, however, "fuel wood" consumption has been excluded from official energy statistics.
- (2) Official energy statistics focus on commercial fuels, i.e. on fuels that are sold to others.
- (3) Captive consumption of by-products as fuels is not treated adequately in official energy statistics. Superficially, the latter give the impression that the consumption of by-product and "waste" materials is much lower than is actually the case.
- (4) Most of the consumption of "wastes" as fuels is by a small number of industries. "Biomass wastes" are utilized by segments of the food industry and pulp/paper industry.
- (5) Utilization of "biomass wastes" in captive, stationary applications (particularly as boiler fuel) has been increasing steadily (mostly in response to the higher cost of purchased fuels but also as a means of avoiding waste disposal problems).
- (6) When wastes are used captively, both costs and benefits can be accurately internalized. Hence, the decision-making process is straightforward. In contrast, schemes that envisage non-captive utilization of waste materials may involve an uneven distribution of costs and benefits and also a complex decision-making process or chain of decisions. Important characteristics of such a "chain" are that (a) any "link" (i.e. individual decision-maker) in the "chain" has effective veto power over the process, and (b) the corollary is that all "links" must perceive a net benefit to themselves (not a net cost).
- (7) Ethanol is the only fuel derived from a biomass resource that has been used commercially for many years as a transportation fuel blendstock. Most of such usage, however, has been outside the U.S. (Brazil, Cuba). Relatively small percentages of synthetic methanol, ethanol, and isopropanol have been used in motor gasoline (as anti-icing additives rather than as fuel extenders). The state of Nebraska is considering an ethanol project.
- (8) Under conditions of petroleum scarcity (or high import cost), ethanol might have more importance as an indirect substitute for petroleum (e.g. as an ethylene feedstock, thereby substituting for a petroleum hydrocarbon feedstock) than as a direct substitute (e.g. as a transportation fuel blendstock).
- (9) After a preparation step, such as drying or dewatering, biomass may be used directly as a stationary fuel (e.g. boiler fuel). Biomass may also be converted, by various means, into higher quality fuels such as methane, methanol, ethanol, and fuel oil.

- "The switch from nonrenewable resources to renewable resources will not occur on the basis of price for many years (personal opinion). What will motivate producers of fuels and chemical feedstocks to switch will be availability."

In 1974, Rohrmann et al. reviewed the potentials for converting forestry, agricultural and municipal wastes to methanol.⁽⁽¹⁻¹⁹⁾⁾ U.S. wastes identified as being potentially available for this purpose were:

	Estimated Annual Quantity, 10 ⁶ tons, (any basis)	Approximate Carbon Content, wt%
Sawdust, shavings, bark and scrap from <u>lumbering</u>	120	50
Trash and garbage from <u>municipal residues</u>	230	40
<u>Agricultural residues</u> such as corn stalks and wheat straw	500	40

The authors note that their statistics are somewhat out of date such that the waste total on a current basis (i.e. 1974) may be about 1 billion tons of 40% carbon content which they then equate to U.S. coal production (603 million tons of approximately 70% carbon content). The report then observes:

- "With some additional rather 'broad brush' estimations, such as a 50% conversion of the total carbon to methanol with a fuel value half that of gasoline, utilization of the total resource of these residues would yield liquid fuel equivalent to about 2×10^9 barrels of gasoline. Realism, of course, requires a much more modest assessment of this potential."
- "The largest U.S. synthetic methanol plants in operation today produce over 200 million gallons per year." Approximately 420 such plants would be needed to produce the 2 billion barrels of gasoline equivalent referred to above.

The remainder of the report reviews various technological approaches to conversion of wastes first to synthesis gas and then to methanol. The need to collect wastes for delivery to the hypothetical methanol plants is recognized as follows:

"For the present, the delivered price of agricultural and wood wastes must include all the cost of collection, storage and hauling if these wastes are to be used for the production of methanol fuel . . . it is estimated that agricultural wastes could be collected, stored and transported up to 33 miles to a processing plant and still stay at about \$8.00/ton. As

environmental regulations become more stringent, the options to the generators of these wastes will become more limited and they will have to bear a higher disposal cost which will, in turn, allow wastes to be hauled a longer distance to processing plants and still be economical at the net delivered price of \$8.00/ton of waste."

No explanation is given of "still be economical," nor of who is assumed to undertake the conversion activities.

A study by Graham et al.⁽¹²⁻¹¹⁾ published in February 1976. concludes that:

- "The energy contribution from a system that uses waste and grown organic feedstocks is estimated as 4 to 12 percent of our current energy consumption."
- "Economic and social issues may be as important as technology in determining the feasibility of such a proposal."
- "There is considerable uncertainty as to how much of the total agricultural waste is collectable for use as feedstocks to conversion systems, but it is probably of the order of tens of millions of tons."
- "The development of a national program for converting organic matter to fuel requires the involvement and coordination of many sectors in the overall enterprise. Such a project organization will eventually have to interface local, state, and federal government agencies with farming, private transportation, chemical conversion operations, fuel storage, marketing, and public utilities."

The study presents a range of estimates of fuel energy potentially available from (a) waste and (b) (deliberately) grown organics. Separate estimates from these two sources are:

	<u>quads/yr.</u>
waste (conservative estimate)	1.4
grown organics (slash pine silviculture)	2.0 to 3.2

Addition of the separate estimates gives around 4 quads/yr., which is equivalent to 5% of current energy consumption.

The report has an appendix that contains rudimentary cost estimates and also the statement: "It is apparent from this cost analysis that the major influence on the cost of the fuel is the charge for biomass feedstock, regardless of the conversion process used. Thus, the economic viability of the system will depend mostly

on the cost of obtaining feedstock. Organic waste, where no charge or even an income is possible, would be the most attractive feedstock for beginning this conversion enterprise." Without further critique of the estimates, the total quantity of "most attractive feedstock" is equivalent to less than 2% of current U.S. energy consumption.

In August 1976, Ware(12-12) reported that, by 1980, "an estimated 1,061 million dry tons of organic solid wastes will be generated each year by municipalities, industry, and agriculture." This estimate is similar to Rohrmann's, and is equivalent to about 13 quads of primary energy or almost an order of magnitude greater than the "conservative" estimate for wastes given by Graham. Most of the numerical difference between the estimates is due to reducing a "potentially available" to a "readily available" figure. However, the "ready availability" of wastes does not imply any level of actual utilization. Ware, who did not make estimates of her own, cited a 1974 EPA report which contained the following numbers:(12-13)

<u>Energy Potentially Recoverable from Municipal Solid Waste (MSW), 1980</u>		
	<u>quads/yr.</u>	<u>B/D. O.E.*</u>
theoretical	1.44	680
available	1.085	512
projected implementation	0.085	40

If the "projected implementation" were to occur, MSW would provide about 0.1% of U.S. energy needs in 1980.

Ware's report also cites cost estimates made in seven earlier studies. A semi-quantitative pattern of costs is evident, as suggested by the approximate Index in the final column.

	<u>Index (Relative Cost)</u>
combustion of MSW to produce steam	1
pipeline quality gas by anaerobic digestion of MSW or manure	4
acid hydrolysis of MSW to ethanol	6
conversion of MSW to methanol	10

Recognizing that the estimates from different sources are not on exactly the same basis, and that all of the estimates are probably low on an absolute basis, it appears that:

- using MSW to produce steam is the most economic alternative
- converting MSW to ethanol or methanol may be an order of magnitude more costly than using it to produce steam

*barrels per day of oil equivalent.

- conversion of MSW to pipeline quality gas is intermediate in cost between the boiler fuel and alcohol cases, and is also considerably more expensive than the current range of contract prices for new intrastate natural gas in leading producing states such as Texas, Louisiana, and Oklahoma.

On an economic basis it may be expected that utilization of biomass wastes as fuel will expand in boiler fuel applications before significant penetration of markets that require fuel in a converted form: either a gas or a liquid. In the latter cases, conversion to methane appears the more economic choice. Considering both the potential contribution of organic wastes* to total U.S. energy supply and the potential for displacing petroleum fuels from stationary to transportation uses**, it appears that biomass is unlikely to become a significant source of U.S. transportation fuels for many years. Put differently, the conclusion is that biomass will be no more than a supplemental source of transportation fuels for many years. This conclusion is similar to those already attributed to Lipinsky. It is also supported by the work of Anderson(12-14) who concluded that "because of their costs, early implementation of biosolar conversion schemes will likely not be in the area of transportation synfuels." Anderson also presents the following estimates of the potential quantities of transportation fuels producible from various U.S. biomass resources:

<u>Fuel</u>	<u>Source</u>	<u>Quads/yr.</u>
ethanol by fermentation	U.S. grain crop	1.6
methanol by pyrolysis	agricultural waste	0.18 to 1.5
methanol by pyrolysis	feedlot residues	0.17
methanol by pyrolysis	MSW	0.2 to 0.3
methanol by pyrolysis	forest wastes	0.3
oil by pyrolysis	all organic wastes	1

Since there is no likelihood that the entire U.S. grain crop will be converted to ethanol, the above estimates suggest that the maximum transportation fuel potential from U.S. organic wastes is about 1 quad/yr. -- as methanol, as oil, or as some combination of the two -- assuming that these wastes are not utilized for stationary fuel purposes. As discussed previously, this is not a reasonable assumption. Hence, the overall conclusion from this entire review may be reiterated: biomass will be no more than a supplemental source of U.S. transportation fuels for many years.

*From an economic standpoint, it is clear that organic wastes will generally be cheaper than cultivated biomass.

**e.g. by changing the yield patterns of petroleum refineries.

13. OVERALL RATINGS OF FUELS/PRIME MOVERS

E. N. Cart, Jr.
M. H. Farmer

The criteria to be used in the preliminary screening phase consists basically of four major factors: (1) fuel manufacture criteria; (2) fuel performance criteria from the designer/user viewpoint; (3) compatibility of fuels and prime movers; and (4) fuel logistics factors. The reasons for selecting these four criteria were outlined in Section 2. The basic data on the various fuels and prime movers have been compiled, critiqued, put on a consistent basis, and summarized, in Sections 3 through 12, to serve as a basis for rating the various fuels and prime movers. In the following sections, the rating scale that will be used is explained and the ratings for the four major areas established.

13.1 Rating Scale Used (Likert Scale)

A Likert scale was used for many of the judgmental ratings. This type of scale is a standard tool of the social sciences when measurement is to be made by the judgment of individuals rather than by physical instruments, and especially where a physical measurement is inapplicable. For example, an individual's preference for A over B (or vice versa) is not directly measurable except by the individual's expression of preference. A Likert scale is a means by which preferences may be expressed in a simple numerical way. In principle, the scale may have any number of intervals. In practice, a five-point scale is useful for "screening," i.e., for gross differentiation of preferences. Typically, the five-point scale has the intervals 0, 1, 2, 3, 4 or 1, 2, 3, 4, 5 or -2, -1, 0, +1, +2. While these intervals are identical from a mathematical or statistical standpoint, the -2 to +2 scale has symbolic advantages in cases where A, B, C, D, etc., are to be compared with a "standard." There is the additional advantage that "don't know" or "uncertain" can be rated as zero, instead of being omitted from the comparison.

Suppose that the standard is something that already exists, while A, B, C, etc., are potential alternatives that could exist in the future. Then, for any given criterion of quality, A may be rated relative to the standard as:

+2	signifying	"much better"
+1	"	"better"
0	"	"equivalent" or "don't know"
-1	"	"inferior"
-2	"	"much inferior"

Obviously, "better" and "inferior" may be replaced by other value pairs such as "greater difficulty" and "lesser difficulty." In each of the categories to be rated, the scale used will be defined.

When different criteria are rated using the same Likert scale, it is possible to sum and average the ratings across the various criteria to obtain an overall rating. Such a combination of ratings is open to challenge on the conceptual grounds that the attributes are not additive or not properly weighted in the average (overall) rating. Such an objection is not admissible if all of the individual ratings of A are better than the standard (or all are worse), and does not appear to be of practical consequence if the majority of ratings are in one direction. However, the objection may be valid if there is a fairly even division of plus and minus ratings. It is for this reason that the overall ratings have been used for the purpose of screening only and not to establish an absolute measure of difference among the fuels or fuel systems rated. This screening, by eliminating clearly inferior hypothetical alternatives, narrows the field to a smaller number of more likely alternatives which may then be examined in greater detail that would be possible for the entire field of initial possibilities.

13.2 Fuels Manufacture Ratings

The three factors considered in the fuel manufacture area are:

(1) cost of production, distribution and storage; (2) overall energy efficiency up to point of use; and (3) environmental impact in production.

The rating scale used for the cost of production, distribution and storage was as follows:

<u>Rating</u>	<u>Cost Range - \$/10⁶ BTU (Delivered to Customer)</u>
+2	Up to 3
+1	3 to 6
0	6 to 10
-1	10 to 15
-2	>15

It is recognized that the split into the five ranges is arbitrary. In the case of cost, the fuels can be directly rated since the costs are on a common basis. However, to be able to combine the cost ratings with the other two ratings, it is necessary to put all the criteria on a similar rating scale. The data in Sections 6 and 7 provided the basic information for the ratings shown in the first column in Table 13-1.

The rating scale used for the overall energy efficiency category was as follows:

<u>Rating</u>	<u>BTU of Resource/BTU of Fuel</u>
+2	1-1.3
+1	1.31-1.7
0	1.71-2
-1	2.01-2.5
-2	>2.51

TABLE 13-1

FUEL MANUFACTURE CRITERIA--RATINGS

Fuel	Cost Rating	Overall Energy Efficiency	Environmental Impact in Production				Overall Rating
			Air	Water	Solid	Overall Environmental	
Coal/Methanol Slurry	0	0	1	0	0	0.3	0.1
Coal/Oil Slurry	2	2	2	0	0	0.7	1.6
Coal	2	2	2	0	0	0.7	1.6
Coal Liquids							
- Distillate	0	0	0	0	1	0.3	0.1
- Gasoline	0	0	0	0	1	0.3	0.1
Shale Liquids							
- Distillate	1	1	-1	-1	-1	-1	1
- Gasoline	1	1	-1	-1	-1	-1	1
Methanol from							
- Coal	-1	0	0	0	1	0.3	-0.2
- Biomass	-2	0	0	0	0	0	-0.7
Hydrogen (Liquid) from							
- Coal	-2	-2	0	0	1	0.3	-1.2
- Electrolysis	-2	-2	0	0	0	0	-1.3
Ammonia from							
- Coal	-2	-1	0	0	0	0	-1.0
- Biomass	-2	0	0	0	0	0	-0.7
Oxygenated Compounds							
- Ethanol--Corn	-2	0	0	0	0	0	-0.7
- Ethanol--Sugarcane	-2	0	0	0	0	0	-0.7
Methane (Liquid) from							
- Coal	-1	0	0	0	1	0.3	-0.2
Hydrazine	-2	-1*	0	0	0	0	-1.0

TABLE 13-1 (Continued)

<u>Fuel</u>	<u>Cost Rating</u>	<u>Overall Energy Efficiency</u>	<u>Environmental Impact in Production</u>				<u>Overall Rating</u>
			<u>Air</u>	<u>Water</u>	<u>Solid</u>	<u>Overall Environmental</u>	
Methylamine	-2	-1*	0	0	0	0	-1.0
Acetylene	-2	-2	0	0	0	0	-1.3
Oil from Organic Waste	-1	0	0	0	0	0	-0.3
Electricity from							
- Coal/Nuclear	-1	-2	-1	0	0	-0.3	-1.1
- Solar	-2	0	0	0	0	0	-0.7**

*No direct information available, but given same rating as ammonia because of chemical similarity.

**Probably around -1 if overall energy efficiency included energy to manufacture the recovery equipment.

For the renewable resource base, a zero was used since it is not possible to put the renewable resources on the same basis as for fuels derived from coal or shale. The data in Section 10 formed the basis for the ratings shown in the second column in Table 13-1.

The rating scale used for the environmental criteria was as follows:

<u>Rating</u>	<u>Air Emissions</u> Lbs/10 ⁶ BTU	<u>Water</u> Lbs/10 ⁶ BTU	<u>Solid</u> Lbs/10 ⁶ BTU
+2	<0.01		
+1	0.01-0.1		0-20
0	0.1-0.5	0-1	20-100
-1	>0.5	>1	>100
-2			

In this case, the amount of information was not sufficient to allow all five "numbers" of the rating scale to be used. As was pointed out in Section 8, the source of this data, most processes can be developed to meet existing or proposed environmental standards, so that most of the fuels will carry a zero rating, except for a few which produce more emissions than the others. Shale derived liquids and electricity are the two fuels that fall into this category.

The ratings for air, water and solid emissions were averaged into an overall environmental rating by adding the three individual ratings and dividing by three. The overall environmental rating is then combined with the overall energy efficiency rating and the cost rating by adding all three ratings and divided by three. This means that, for screening purposes, all three categories carry equal weight in the rating system.

The fuels with a rating of zero or greater are as follows (listed in descending order of rating):

1. Coal
2. Coal/oil slurry
3. Shale liquids--distillate
gasoline
4. Coal liquids--distillate
gasoline
5. Coal/methanol slurry

Fuels with a rating of zero to minus 0.5 are as follows:

6. Methane (liquid)
7. Methanol (from coal)
8. Oil from organic waste

The overall ratings do not have any absolute significance, but they do indicate which fuels, from a manufacturing viewpoint, are most attractive and deserve further consideration. Fuels with a rating of minus 0.5 or greater (on a negative scale) that would not appear to be attractive from a manufacturing standpoint are as follows:

9. Ethanol (corn)
10. Methanol (biomass)
11. Ethanol (sugarcane)
12. Ammonia (biomass)
13. Hydrazine
14. Methylamine
15. Electricity
16. Hydrogen (liquid)
17. Acetylene

13.3 Fuel Performance Ratings from Designer/User Viewpoint

In evaluating the various fuels from a performance standpoint, six different factors were considered: (1) toxicity, (2) safety, (3) materials compatibility, (4) storage requirements, (5) convenience in handling and storage, and (6) environmental impact during use. For this particular category, it is possible to use the current petroleum fuel as a reference. The particular scale that was used for each of the six factors is defined in the following sections. Section 3 is the basis for the data used for most of these ratings.

13.3.1 Toxicity

The rating scale used for the toxicity comparison is as follows:

- 0 -- Comparable to current petroleum based fuel
- 1 -- Moderately more toxic than petroleum fuels
- 2 -- Potentially much more toxic than petroleum fuels

As shown in Table 13-2 for coal liquids, the distillate fraction (diesel/jet fuel) is shown with a zero rating. This assumes that the liquids have been upgraded to meet the current specification. The -1 for gasoline and fuel oil reflect the more aromatic nature of coal liquids, compared to petroleum. It is assumed that for gasoline it would be desirable to take advantage of this characteristic of coal gasolines, while for fuel oil, it would not be economical to try and upgrade the product.

13.3.2 Safety

The rating scale used for the safety comparison is as follows:

TABLE 13-2

FUEL PERFORMANCE CRITERIA

Fuel	Toxicity	Safety	Materials Compatibility	Storage Requirements			Convenience in Handling and Storage	Environmental Impact During Use	Overall Rating
				Weight (Fuel Only)	Volume (Fuel Only)	Avg.			
Petroleum									
- Present Specification	0	0	0	0	0	0	0	0	0
- Broadcut	0	+1	0	0	0	0	0	0	+0.2
Coal	0	+1	-1	-1	-1	-1	-1	-2	-0.7
Coal/Methanol Slurry	-1	0	-1	-2	-2	-2	-2	-1	-1.2
Coal/Oil Slurry	0	+1	-1	-1	+1	0	-2	-1	-0.5
Coal Liquids									
- Gasoline	-1	0	0	0	0	0	0	-1	-0.3
- Diesel/Jet Fuel	0	+1	0	0	0	0	0	-1	0
- Fuel Oil	-1	+1	0	0	+1	0.5	0	-1	-0.1
Shale Oil Liquids									
- Raw	0	0	-1	0	-1	-0.5	-2	-1	-0.7
- Syncrude	0	0	0	0	0	0	0	0	0
Methanol	-1	0	-1	-2	-2	-2	-1	+1	-0.7
Hydrogen	0	-1	-1	+2	-2	0	-2	+2	-0.3
Ammonia	-2	0	-2	-2	-2	-2	-1	-1	-1.3
Oxygenated Compound									
- Ethanol	-1	0	-1	-2	-2	-2	-1	+1	-0.7
- Higher Alcohols	-1	0	-1	-2	-2	-2	-1	+1	-0.7
Methane	0	-1	0	+1	-2	-0.5	-1	+1	-0.3
Hydrazine	-2	0	-2	-2	-2	-2	-2	0	-1.3
Methylamine	-2	-1	-2	-1	-2	-1.5	-2	0	-1.4
Acetylene	0	-2	0	-2	-1	-1.5	-2	0	-1.0
Oil from Organic Waste	0	0	0	-1	0	-0.5	0	0	-0.1

- +1 -- Safer than the current petroleum fuel
- 0 -- As safe as the current petroleum fuel
- 1 -- Not as safe as the current petroleum fuel

The data from Table 3-7 were used to determine the ratings shown in Table 13-2. The broadcast fuel is rated safer than the current petroleum fuel on the basis that it will have a lower flash point.

13.3.3 Materials Compatibility

The materials that are considered from a fuels compatibility standpoint are those in contact with the fuel, such as various elastomers and metals in the prime movers and the distribution system. The rating scale used was as follows:

- 0 -- Satisfactory. Same as the current fuel being used
- 1 -- Borderline when compared to the current fuels
- 2 -- Unsatisfactory, based on the materials currently used. Obviously a system could be designed for a given fuel that would be satisfactory.

Coal and coal/slurries would be considered a borderline fuel when compared to the current oil system, due to the abrasive nature of the solids. Coal liquids are rated as satisfactory, but there may be an elastomer incompatibility problem which could be easily solved. Ammonia is rated as unsatisfactory from the problem created with copper, zinc, and brass in contact with this fuel. Methylamine would be expected to resemble ammonia. Hydrazine is corrosive to cobalt, copper, pure iron, lead, manganese, magnesium, tin, and zinc.

13.3.4 Storage Requirements

The storage requirements from both a weight and volume standpoint were considered. The data in Table 3-3 were used in conjunction with the following scale to rate the various fuels:

<u>Rating</u>	<u>Ratio from Table 3-3</u>
+2	<0.5
+1	0.5-0.99
0	Same as Petroleum (1.00-1.09)
-1	1.1-1.5
-2	>1.5

The ratings for weight and volume were then averaged. It is recognized that for some modes of transportation, weight is more important, such as for aircraft.

13.3.5 Convenience in Handling and Storage

Some of the characteristics related to the handling and bulk storage of the fuels are the freezing point or pour point, water solubility of the fuel, storage stability, and emulsion forming tendencies. The data from Table 3-4 were used with the following rating scale to arrive at the values shown in Table 13-2:

- +1 -- Better than current fuels
- 0 -- Equal to current petroleum fuels
- 1 -- Slightly poorer than petroleum fuels
- 2 -- Much poorer than current petroleum fuels

The coal slurries (oil or methanol) are rated a -2 due to the potential problems of maintaining the coal in suspension. Methanol and the other alcohols are rated as a -1 because of the problems that may be caused if there is any water in the distribution system. Hydrogen is rated a -2 since a cryogenic liquid would have to be handled. Liquid methane is rated a -1 for the same reason, but it is not as severe a problem as liquid hydrogen due to the difference in temperatures involved.

13.3.6 Environmental Impact During Use

The rating scale used for the environmental impact during use criteria was as follows:

- +2 -- Better in emissions of at least two pollutants
- +1 -- Better in emissions of one pollutant
- 0 -- Comparable to current fuel
- 1 -- Poorer than conventional fuels
- 2 -- Much poorer than conventional fuels

Direct use of coal is rated a -2 due to increased particulate emissions as well as increased SO₂ and NO_x emissions. The use of coal slurries would reduce the emissions, since the fuel would contain only 40% by weight of coal, but are still expected to be poorer than conventional fuels. Coal liquids are rated a -1 due to the uncertainty about PNA emissions. Shale liquids are assumed upgraded to the same nitrogen and sulfur levels so they would be expected to have the same emissions as conventional fuels. Ammonia would produce increased NO_x emissions; this is the reason for a -1 rating for this fuel. Hydrazine and methylamine may also cause increased emissions but since this is not known, a 0 rating is used. Hydrogen is rated a +2 due to its producing less emissions than the other fuels and also no CO₂.

13.3.7 Overall Ratings

The six ratings are summed and divided by six to arrive at the overall rating shown in Table 13-2. The averages have been rounded to the nearest tenth. By definition, the current petroleum fuel would be rated 0 and any fuel that has about the same properties as petroleum would be near 0. Those fuels with a rating from -0.5 to +0.5 are as follows (listed in descending order):

1. Broadcut (petroleum)
2. Present petroleum fuels
3. Coal distillate
4. Shale distillate/gasoline
5. Oil from organic waste
6. Coal fuel oil
7. Coal gasoline
8. Hydrogen
9. Methane
10. Coal/oil slurry

Those fuels with a rating of less than -0.5 are as follows:

11. Coal
12. Methanol
13. Ethanol and higher alcohols
14. Acetylene
15. Coal/methanol slurry
16. Ammonia
17. Hydrazine
18. Methylamine

13.4 Compatibility of Fuels and Prime Movers

Another factor considered in evaluating the performance potential for each fuel is the compatibility of the fuels and various prime movers. Table 13-3 summarizes how the various fuels may operate in a given type of prime mover, based on information from the literature and the combustion properties of each fuel. The rating scale used was as follows:

- 0 -- No modifications required; could be used in current designs
- 1 -- Minor modifications required
- 2 -- Major modifications required
- 3 -- Not practical; would require an entirely new design

It is recognized that an entirely different type of engine could possibly be designed for the 2000+ period, but for this preliminary screening it will be assumed that the fuels should be compatible with current designs.

In Table 13-3, several fuels/prime mover combinations are rated a -2 even though it was mentioned in Section 11 (Table 11-1) that there is very little hope of effecting a match between these fuels and prime movers. In some of these cases, the problems anticipated may be tolerated and deserve further consideration if a fuel or prime mover looks attractive for other reasons. However, there are some fuels that simply are not potentially usable in certain types of engines and these are shown in Table 13-4.

As shown in Table 13-3, it is possible to sum the ratings for a given fuel and get a semi-quantitative comparison of the relative difficulty of substitution of fuels into various types of engines. Based on the totals shown, the following is a list of the relative difficulty of substitution of the fuels (listed in order of increasing difficulty of substitution):

TABLE 13-3

COMPATIBILITY OF FUELS AND PRIME MOVERS

Fuel	Otto Cycle		Diesel		Gas Turbine		Stirling	Free Piston	Steam	Σ
	Normal Spark Ignition	Stratified*,** Charge	Marine Service (Low Speed)	Railroad (Medium Speed)	Stationary	Aircraft				
Petroleum										
- Present Specification	0	0	0	0	0	0	0	0	0	0
- Broadcut	-3	0	0	-1	0	0	0	0	0	-4
Coal	-3	-3	-3	-3	-2***	-3	-2	-3	0	-22
Coal/Methanol Slurry	-3	-3	-2***	-3	-2***	-3	-2	-2***	0	-20
Coal/Oil Slurry	-3	-3	-2***	-3	-2***	-3	-2	-2***	0	-20
Coal Liquids										
- Gasoline	0	0	-3	-3	0	-3	0	0	0	-9
- Diesel/Jet Fuel	-3	-1	0	0	0	-1/0	0	0	0	-4
- Fuel Oil	-3	-3	0	-1	0	-2	0	0	0	-9
Shale Oil Liquids										
- Raw	-3	-1	0	-1	0	-3	0	0	0	-6
- Syncrude	-3	-1	0	0	0	0	0	0	0	-4
Methanol	-1	0	-2***	-2***	0	0	0	-2	0	-7
Hydrogen	-2	-1	-2	-2***	0	0	0	-2***	0	-9
Ammonia	-2	-2	-2***	-2	-1	-2	0	-2***	0	-13
Oxygenated Compound										
- Ethanol	-1	0	-2	-2	0	0	0	-2	0	-7
- Higher Alcohols	-1	0	-2	-2	0	0	0	-2	0	-7
Methane	0	0	-2	-2	0	0	0	-2***	0	-6
Hydrazine	-3	-3	-3	-3	-1	-3	0	-2***	0	-18
Methylamine	-3	-3	-3	-3	-1	-3	0	-2***	0	-18
Acetylene	-3	-3	-3	-3	0	-3	0	-2***	0	-17
Oil from Organic Waste	-3	-3	0	0	0	-1	0	0	0	-7

*Type under development for stationary application.

**Would not be same fuel as for normal spark ignited engine.

***No literature data on these fuels/engine combinations, but worthy of further consideration.

TABLE 13-4

SUMMARY OF FUEL/ENGINES THAT SHOULD NOT BE CONSIDERED

Fuels	Otto Cycle		Diesel		Gas Turbine		Stirling	Free Piston	Steam
	Normal Spark	Stratified Charge	Marine	Railroad	Station- ary(1)	Aircraft			
Petroleum									
- Broadcut	X								
Coal	X	X	X	X		X		X	
Coal/Oil Slurry	X	X		X		X			
Coal/Methanol Slurry	X	X		X		X			
Coal Liquids									
- Gasoline			X	X		X			
- Diesel/Jet Fuel	X								
- Fuel Oil	X	X				X			
Shale Oil Liquids									
- Gasoline						X			
- Diesel/Jet	X								
- Fuel Oil						X			
Methanol									
Ethanol/Higher Alcohols									
Methane									
Hydrogen									
Ammonia									
Hydrazine	X	X	X	X		X			
Methylamine	X	X	X	X		X			
Acetylene	X	X	X	X					
Oil - Organic Waste	X					X			

X -- Indicated fuel/engine combinations that are incompatible.

(1) For some fuels, clean-up would be ahead of the gas turbine, or in the case of coal, a FBC unit would be used.

1. Broadcut (petroleum)
2. Coal distillate
3. Shale distillate
4. Methane
5. Methanol
6. Ethanol and higher alcohols
7. Oil from organic wastes
8. Coal gasoline
9. Shale gasoline
10. Coal and shale fuel oil
11. Hydrogen
12. Ammonia
13. Acetylene
14. Hydrazine
15. Methylamine
16. Coal/oil slurry
17. Coal/methanol slurry
18. Coal

It is also possible to sum the ratings for the various types of prime movers and obtain a semi-quantitative comparison of which types of prime movers have the greatest degree of flexibility for using different types of fuels. Based on the totals of the columns and the rows in Table 13-3, the following is a list of the prime movers in descending order of fuel flexibility:

1. Boiler/steam turbine
2. Stirling
3. Stationary gas turbine
4. Free piston engine
5. Aircraft gas turbine
6. Otto cycle-stratified charge
7. Slow speed diesel
8. Medium speed diesel
9. Otto cycle-normal spark ignition

There is a large gap between the ratings on the first three prime movers listed and the other six. Thus, the first three show the greatest potential for burning practically any type of fuel and are the likely candidates for fuel substitution. These are also the types of prime movers to be considered in the future since they offer greater flexibility to use poorer quality fuels.

13.5 Fuel Logistics Ratings

The ratings in Table 13-5 are based on the criteria and judgments reported in Table 12-4. The rating scale runs from -2 to +2 with the following implications:

- 2 -- Considerable difficulty (problem, lower availability) relative to current situation

TABLE 13-5

FUEL LOGISTICS RATINGS

Fuel	Fuel Availability by 1990	Compatibility with Present		International Considerations	Overall Rating
		Fuels	System		
Coal	+2	-2	-2	0	-0.5
Coal-in-Oil Slurry	0	-1	-1	0	-0.5
Coal-in-Methanol Slurry	-1	-1	-1	-1	-1.0
Coal Liquids (Upgraded)	-1	0	0	0	-0.3
Shale Oil (Raw)	0	-1	-1	-1	-0.8
Shale Liquids (Upgraded)	0	0	0	0	0
Methanol from Coal	-1	-1	-1	0	-0.8
Methanol from Biomass	-2	-1	-1	0	-1.0
Hydrogen from Coal	-1	-2	-2	0	-1.3
Hydrogen by Electrolysis	-2	-2	-2	0	-1.5
Methane from Coal	-1	-1	-1	0	-0.8
Ammonia from Coal	-1	-2	-2	-2	-1.8
Ammonia from Biomass	-2	-2	-2	-2	-2
Hydrazine	-2	-2	-2	-2	-2
Methylamine	-2	-2	-2	-2	-2
Acetylene	-2	-2	-2	-2	-2
Ethanol from Corn	-1	0	-1	0	-0.5
Ethanol from Sugarcane	-1	0	-1	0	-0.5
Oil from Organic Waste	-2	0	0	0	-0.5
Electricity from Coal	0	-2	-2	0	-1.0
Electricity from Nuclear Energy	0	-2	-2	0	-1.0
Electricity from Solar Energy	-2	-2	-2	0	-1.8

- 1 -- Some difficulty (problem: lower availability) relative to current situation
- 0 -- Similar to present situation or unknown
- +1 -- More favorable than current situation
- +2 -- Considerably more favorable than current situation

It is recognized that the logistical ratings are inherently biased against new or different types of fuels. This is realistic because of the difficulty of introducing changes into the existing logistical system (which functions smoothly). The purpose of the ratings is not to make this obvious point but rather to indicate the relative differences among the various alternative fuels.

The year 1990 has been chosen for comparison of availability of the alternative fuels. This choice was made because: (a) an earlier date, say 1980, would eliminate many of the fuels on the basis of non-availability; (b) a substantially later date, say 2000, would produce a hypothetical availability of most of the fuels but this "availability" would be extremely speculative, and (c) if the fuel possibilities are to become realities, they must pass through a transitional stage of limited availability; 1990 appears suitable for assessment of this transitional quality because it is sufficiently far in the future to permit transitions to be underway but not so far in the future that any transition would be hypothetically possible.

The compatibility ratings are based directly on Table 12-4, by simple conversion of "yes" into a zero rating, "some problems" into a -1 rating, and "no" into a -2 rating.

Most of the "generally unfavorable" or "probably unfavorable" ratings in the "International Considerations" column of Table 12-4 have been given a -2 rating in Table 13-5. Somewhat arbitrary exceptions have been made for coal-in-methanol slurry and raw shale oil for which the ratings are -1. The intent here is not to penalize the possible marine applications of these fuels unnecessarily.

Alcohols other than methanol and ethanol, i.e., "higher" alcohols, are excluded from Table 13-5 because their availability in 1990 is considered to be insignificant.

The overall ratings in the final column of Table 13-5 are the sum of the ratings in the preceding columns divided by four. The overall ratings do not have any absolute significance; rather they are intended for screening purposes. For example, fuels with overall ratings more favorable than -1 are "screened in" from the standpoint of logistics, thereby meriting more detailed examination in other respects. Fuels with overall logistical ratings ranging from -1 to -1.5 would be difficult to introduce commercially unless their logistical disadvantages were compensated by significant advantages in other respects. Finally, it is almost inconceivable that other advantages could offset the logistical disadvantages of the fuels with overall ratings below -1.5; effectively, such fuels are "screened out."

13.6 Overall Fuel Ratings

To arrive at an overall ranking of the various fuels, the ratings from Table 13-1 on the manufacturing criteria, the ratings from Table 13-2 on performance, and the ratings from Table 13-5 on the logistics ratings were combined as shown in Table 13-6. For the preliminary screening, equal weight has been given to the three categories and the sum of the three individual overall ratings is used to arrive at the ranking shown in Table 13-7.

While the absolute numbers have no meaning, they do indicate that the fuels tend to fall into four groups. The first nine fuels listed are the prime candidates with ratings of 1 to -1. The second group with ratings between -1.1 and -2 are probably of interest. The next five fuels have ratings in the -2.1 to -3.1 range and are borderline from the standpoint of attractiveness. There may be special reasons why these would look attractive. For example, electricity has a special application in railroads and pipelines, but no application in marine or aircraft. In fact, it could be questioned if electricity should even be included in this comparison. The last group of five fuels, with ratings in the -4 range, are clearly not attractive and should be dropped from further consideration.

There are a couple of possible surprises in where the various fuels are ranked. These surprises are: (1) liquid methane ranked fairly high and will require more in-depth analysis; and (2) oil from organic waste also ranked fairly high, however potential availability may be limited.

TABLE 13-6

CRITERIA IN FUEL SELECTION FOR NON-HIGHWAY TRANSPORTATION FUELS

<u>Fuel</u>	<u>Manufacture</u>	<u>Performance</u>	<u>Logistics</u>	<u>Overall</u>
Coal/Methanol Slurry	0.1	-1.2	-1	-2.1
Coal/Oil Slurry	1.6	-0.5	-0.5	+0.6
Coal	1.6	-0.7	-0.5	+0.4
Coal Liquids (by Process)				
Gasoline	0.1	-0.3	-0.3	-0.5
Distillate	0.1	0	-0.3	-0.2
Shale Liquids				
Raw Shale Oil	1	0	-0.8	+0.2
Syncrude-Gasoline	1	0	0	1
-Distillate				1
Methanol from				
Coal	-0.2	-0.7	-0.8	-1.7
Biomass	-0.7	-0.7	-1.0	-2.4
Hydrogen from				
Coal	-1.2	-0.3	-1.3	-2.8
Electrolysis	-1.3	-0.3	-1.5	-3.1
Ammonia from				
Coal	-1.3	-1.3	-1.8	-4.1
Biomass	-0.7	-1.3	-2.0	-4
Oxygenated Compounds				
Ethanol-Corn	-0.7	-0.7	-0.3	-1.7
Ethanol-Sugar Cane	-0.7	-0.7	-0.3	-1.7
Methane from Coal	-0.2	+0.3	-0.8	-0.7
Hydrazine	-0.7	-1.3	-2	-4.3
Methylamine	-0.7	-1.4	-2	-4.4
Acetylene	-1.3	-1	-2	-4.3
Oil from Organic Waste	-0.3	-0.1	- .5	-0.9
Electricity from				
Coal	-1.1		-1	-2.1
Nuclear	-1.1	N/A	-1	-2.1
Other-Solar	-0.7		-2	-2.1

13-17

TABLE 13-7

OVERALL FUEL RANKINGS FOR NON-HIGHWAY TRANSPORTATION

<u>Fuels</u>		
Shale Liquids--Gasoline	1	}
Distillate	1	
Coal/Oil Slurry	+0.6	
Coal	+0.4	
Raw Shale Oil	+0.2	
Coal Liquids--Distillate	-0.2	}
Gasoline	-0.5	
Methane (L)	-0.7	
Oil--From Organic Waste	-0.9	
Ethanol--Corn	-1.7	
Sugar Cane	-1.7	}
Methanol--Coal	-1.7	
Coal/Methanol Slurry	-2.1	}
Electricity--Coal/Nuclear	-2.1	
Methanol--Biomass	-2.4	
Hydrogen--Coal	-2.8	
Hydrogen--Electrolysis	-3.1	
Ammonia--Biomass	-4	}
Coal	4.1	
Hydrazine	-4.3	
Methylamine	-4.4	
Acetylene	-4.4	

Prime Candidates

Probably of Interest

 Borderline--May be
 Special Reasons
 Why These Would
 Look Attractive

Clearly not Attractive

14. SELECTION OF FUELS AND PRIME MOVERS FOR MORE DETAILED STUDY

E. N. Cart, Jr.

One of the major objectives of the preliminary screening was to narrow down the list of alternate fuels and prime movers for more detailed evaluation. This section covers the procedure used to select the fuels of potential interest for the various prime movers and to then recommend the fuels/prime movers that will be considered for an in-depth review for each mode of transportation.

14.1 Selection of Fuels for Each Type of Prime Mover

The same procedure outlined in Section 13 was used to rank the fuels that would be of potential interest for each type of prime mover considered for non-highway transportation. Table 14-1 illustrates the methodology used. The overall ratings from Tables 13-1, 13-2, and 13-5 were the source of the ratings shown for manufacture, performance and logistics, respectively. The engine/fuel compatibility rating is from Table 13-3. Any engine/fuel rating of -3 means that this fuel would not be considered further for this type of engine since it would be impractical to modify this particular type of engine to use this particular fuel. The overall rating is simply the sum of the four individual ratings. Similar tables were prepared for the other eight types of prime movers.

The ranking of the potential fuels for each of the nine prime movers is given in Tables 14-2 through 14-10. The numerical rating is included to give a rough indication of how close the ranking was or how far apart some of the fuels were. For example, in Table 14-2 the first four fuels are essentially equal in their ratings, while the last three fuels are rated considerably lower than the first group. Fuels with ratings greater than -4 are not included.

14.2 Final Selection of Fuels and Prime Movers for Each Mode of Non-Highway Transportation

The various prime movers of interest for each mode of non-highway transportation are shown in Table 14-11. In the case of pipeline, rail, and marine, the number of prime movers is greater than can be included in an in-depth study. Therefore, the prime movers that will be considered for further study and the fuels that will be considered are outlined in the following sections.

14.2.1 Marine

The fuels and prime movers recommended for further study in Task 3 for marine applications are shown in Table 14-12. The numbers shown indicate the relative ranking of the fuels for each type of prime mover. This is a preliminary ranking and may change in the detailed evaluation.

TABLE 14-1

CRITERIA IN FUEL SELECTION FOR NON-HIGHWAY TRANSPORTATION FUELS

Medium Speed Diesel (Railroad)

<u>Fuel</u>	<u>Manufacture</u>	<u>Performance</u>	<u>Logistics</u>	<u>Engine/Fuel Compatibility</u>	<u>Overall</u>
Coal/Methanol Slurry	0.1	-1.2	-1	-3*	-5.1
Coal/Oil Slurry	1.6	-0.5	-0.5	-3*	-2.4
Coal	1.6	-0.7	-0.5	-3*	-2.6
Coal Liquids (by Process)					
- Gasoline	0.1	-0.3	-0.3	-3*	-3.5
- Distillate	0.1	0	-0.3	0	-0.2
Shale Liquids					
- Raw Shale Oil	1	0	-0.8	-1	-0.8
- Syncrude	1	0	0	-1	0
Methanol from					
- Coal	-0.2	-0.7	-0.8	-2	-3.7
- Biomass	-0.7	-0.7	-1.0	-2	-4.4
Hydrogen from					
- Coal	-1.2	-0.3	-1.3	-2	-4.6
- Electrolysis	-1.3	-0.3	-1.5	-2	-5.1
Ammonia from					
- Coal	-1.3	-1.3	-1.8	-2	-6.4
- Biomass	-0.7	-1.3	-2.0	-2	-6
Oxygenated Compounds					
- Ethanol--Corn	-0.7	-0.7	-0.3	-2	-3.7
- Ethanol--Sugar Cane	-0.7	-0.7	-0.3	-2	-3.7
Methane from					
- Coal	-0.2	+0.3	-0.8	-2	-2.7

TABLE 14-1 (Continued)

<u>Fuel</u>	<u>Manufacture</u>	<u>Performance</u>	<u>Logistics</u>	<u>Engine/Fuel Compatibility</u>	<u>Overall</u>
Hydrazine	-0.7	-1.3	-2	-3*	-6.7
Methylamine	-0.7	-1.4	-2	-3*	-7.1
Acetylene	-1.3	-1	-2	-3*	-7.3
Oil from Organic Waste	-0.3	-0.1	-0.5	0	-0.9

*This fuel not considered for this engine since it would be impractical to modify existing engines to use this fuel.

TABLE 14-2

RANKING OF POTENTIAL FUELS FOR
MEDIUM SPEED DIESEL ENGINES (RAILROADS)

Shale Distillate	0
Coal Distillate	-0.2
Raw Shale Oil	-0.8
Oil from Organic Waste	-0.9
Methane (L)--Coal	-2.7
Ethanol--Corn	-3.7
--Sugar Cane	-3.7
Methanol--Coal	-3.7

TABLE 14-3RANKING OF POTENTIAL FUELS FOR
LOW SPEED DIESEL ENGINES (MARINE USE)

Shale Distillate	1
Raw Shale Oil	+0.2
Coal Distillate	-0.2
Oil from Organic Waste	-0.9
Coal/Oil Slurry	-1.4
Methane (Liquid)	-3.3
Ethanol--Corn	-3.7
--Sugar Cane	-3.7
Methanol--Coal	-3.7

TABLE 14-4

RANKING OF POTENTIAL FUELS FOR
STATIONARY GAS TURBINE ENGINES

Shale--Distillate	1
--Raw Shale Oil	+0.2
Coal Distillate	-0.2
Shale Gasoline	-0.2
Coal--Gasoline	-0.5
Methane (Liquid)--Coal	-0.7*
Oil from Organic Waste	-0.9
Ethanol--Corn	-1.7
--Sugar Cane	-1.7
Coal/Oil Slurry	-1.4
Coal	-1.6
Methanol--Coal	-1.7
--Biomass	-2.4
Hydrogen (l)--Coal	-1.8
(l)--Electrolysis	-3.1

*Rating would be higher for gaseous methane.

TABLE 14-5RANKING OF POTENTIAL FUELS FOR
AIRCRAFT GAS TURBINES

Shale Distillate	1
Coal Distillate	-0.2
Methane (Liquid)	-0.7
Oil from Organic Waste	-0.9
Ethanol	-1.7
Methanol	-1.7/2.4
Hydrogen (Liquid)	-2.8/-3.1
Broadcut Petroleum	(Not ranked but included for further consideration)

TABLE 14-6RANKING OF POTENTIAL FUELS FOR
OTTO CYCLE-NORMAL SPARK IGNITION

Shale--Gasoline	1
Coal--Gasoline	-0.5
Methane (l)	-0.7
Ethanol--Corn	-2.7
--Sugar Cane	-2.7
Methanol--Coal	-2.7
--Biomass	-3.4
Hydrogen (l)	-4.8/-5.1*

*Included even though rating is below -4
cut-off point.

TABLE 14-7RANKING OF POTENTIAL FUELS FOR
OTTO CYCLE-STRATIFIED CHARGE

Shale--Gasoline	0
--Distillate	0
Coal Gasoline	-0.5
Raw Shale Oil	-0.8
Methane (Liquid)	-0.7
Oil from Organic Waste	-0.9
Coal--Distillate	-1.2
Ethanol	-1.7
Methanol	-2.7/-3.4

TABLE 14-8RANKING OF POTENTIAL FUELS
FOR STIRLING ENGINES

Shale Liquids	1
Raw Shale Oil	+0.2
Coal--Distillate	-0.5
--Gasoline	-0.2
Methane (l)	-0.7
Oil from Organic Waste	-0.9
Coal/Oil Slurry	-1.4
Coal	-1.6
Methanol--Coal	-1.7
Ethanol--Sugar Cane/Corn	-1.7
Coal/Methanol Slurry	-2.1
Methanol--Biomass	-2.4
Hydrogen (l)--Coal	-2.8
--Electrolysis	-3.1

TABLE 14-9RANKING OF POTENTIAL FUELS
FOR FREE PISTON ENGINES

Shale--Liquids	1
Raw Shale Oil	+0.2
Coal--Distillate	-0.2
--Gasoline	-0.5
Oil from Organic Waste	-0.9
Coal/Oil Slurry	-1.4
Methane (Liquid)	-2.7
Ethanol--Corn	-3.7
--Sugar Cane	-3.7
Methanol--Coal	-3.7

TABLE 14-10

RANKING OF POTENTIAL FUELS
FOR STEAM BOILER/TURBINE PRIME MOVERS

Shale Liquids	1
Coal/Oil Slurry	+0.6
Coal	+0.4
Raw Shale Oil	+0.2
Coal Liquids	-0.2/-0.5
Methane (ℓ)	-0.7
Oil from Organic Waste	-0.9
Ethanol--Corn	-1.7
--Sugar Cane	-1.7
Methanol--Coal	-1.7
Coal/Methanol Slurry	-2.1
Methanol--Biomass	-2.4
Hydrogen--Coal	-2.8
--Electrolysis	-3.1

TABLE 14-11

PRIME MOVERS OF INTEREST FOR NON-HIGHWAY TRANSPORTATION

<u>Type of Prime Mover</u>	<u>Mode of Transportation</u>			
	<u>Pipeline</u>	<u>Rail</u>	<u>Marine</u>	<u>Aircraft</u>
Diesel Engine	X	⊗	⊗	
Gas Turbine	⊗	X	X	⊗
- Turboprop				X
- Advanced Turbofan				X
- Supersonic Propulsion				X
Electric Motor	⊗	X		
Internal Comb. Engine (SI)	⊗		X	X
Fuel Cell	X	X	X	
Stirling Engine		X	X	
Steam Engine	X	X	⊗	
Stratified Charge	X	X	X	
Free Piston		X	X	

○ Major Prime Mover in use Currently

TABLE 14-12

FUELS/PRIME MOVERS SELECTED FOR IN-DEPTH STUDY FORMARINE

<u>Fuel</u>	<u>Diesel</u>	<u>Steam Engine</u>	<u>Free Piston</u>	<u>Gas Turbine</u>	<u>Stirling</u>	<u>Fuel Cell</u>
Shale Liquids	1	1	1	1	1	*
Raw Shale Oil	2	4	2	2	2	
Coal Liquids	3	5	3	3	3	*
Oil from Organic Waste	4		4	5	5	
Coal/Oil Slurry	5	2	5	6	6	
Methane (l)	6	6	6	4	4	
Coal		3				

*Light distillate

Actually, ethanol was one of the fuels that rated in the top six fuels for gas turbine and Stirling engines. However, the potential problems of handling ethanol in a marine environment, from the water miscibility and corrosion standpoint, ruled this fuel out. Fuel cells will also be considered, using a light distillate from coal and/or shale as fuel to the steam reformer.

14.2.2 Railroads

The fuels and prime movers recommended for further study for the railroad applications are shown in Table 14-13. Three different types of prime movers will be considered, as well as a fuel cell. An in-depth study of electrification of the railroads is beyond the scope of this study.

14.2.3 Pipeline

The fuels and prime movers recommended for further study for the pipeline application are shown in Table 14-14. Four different types of prime movers will be considered in addition to electric motors and fuel cells.

14.2.4 Aircraft

The fuels and prime movers recommended for further study for the aircraft mode of transportation are shown in Table 14-15. In this case, only the aircraft gas turbine, as a general class, will be considered. The Otto-normal spark ignition type prime mover used for general aviation will not be included in the in-depth study. The potential volume of fuel required is very small and does not warrant a great deal of study. The potential fuels of interest in this type of engine are shown in Table 14-15.

A broadcast petroleum fuel has been added to the list of fuels, even though it is not an alternate fuel as defined for this study. It has been included to illustrate what a change in the specification could do to increase the volume of potential jet fuel in times of an emergency. Also, it will give an indication of what a broadcast fuel may look like if produced from coal or shale oil.

TABLE 14-13

FUELS/PRIME MOVERS SELECTED FOR IN-DEPTH STUDY FOR
RAILROADS

<u>Fuel/Energy Carrier</u>	<u>Diesel</u>	<u>Steam Engine</u>	<u>Stirling Engine</u>	<u>Gas Turbine</u>	<u>Electric⁽¹⁾</u>	<u>Fuel Cell</u>
Shale Distillate	1	1	1	1		*
Coal Distillate	2	5	3	3		*
Raw Shale Oil	3	4	2	2		
Oil from Organic Waste	4		5	5		
Methane	5	6	4	4		
Ethanol	6		6	6		
Coal/Oil Slurry		2				
Coal		3				

(1) Beyond scope of this study to make an in-depth comparison of rail electrification with other modes.

*Light distillate as feed to a steam reformer.

TABLE 14-14

FUELS/PRIME MOVERS SELECTED FOR IN-DEPTH STUDY FORPIPELINE

<u>Fuel/Energy Carrier</u>	<u>Diesel*</u> (Med. Speed)	<u>Stationary*</u> <u>Gas</u> <u>Turbine</u>	<u>Otto Cycle</u>		<u>Electric</u> <u>Motor</u>	<u>Fuel</u> <u>Cell</u>
			<u>Stratified</u> <u>Charge</u>	<u>Spark</u> <u>Ignited</u>		
Shale--Distillate	1	1	1			
--Raw	3	2	3			
Coal--Distillate	2	3	5			
Shale--Gasoline		4		1		
Coal--Gasoline		5	2	2		
Methane (L)	4	6	4	3		X**
Ethanol	5		6	4		
Methanol	6		7	5		
Electricity					X**	

*Will include combined cycle consideration.

**Will be included in study.

TABLE 14-15

FUELS/PRIME MOVERS SELECTED FOR IN-DEPTH STUDY FOR

AIRCRAFT

<u>Fuel</u>	<u>Gas Turbine</u>	<u>Otto Normal Spark Ignition(1)</u>
Shale Distillate	1	
Coal Distillate	2	
Methane (l)	3	
Hydrogen (l)	4	
Broadcut Petroleum	Not Rated	

(1) Will not be covered in-depth in Task 3. Possible fuels of interest are gasoline (from shale or coal), ethanol, methanol, and methane (l).

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15. Supplementary Notes															
16. Abstracts <p>A planning study has been made for DOE on alternate fuels for non-highway transportation (aircraft, rail, marine and pipeline). The purpose of the study was to provide DOE with a recommendation of what alternate fuels may be of interest to non-highway transportation users from now through 2025 and to recommend R&D needed to allow non-petroleum derived fuels to be used in non-highway transportation.</p> <p>In the near term (present 1985), there is unlikely to be any major change in the fuels used in any of the four modes of transportation except that the average quality of the marine fuel is likely to get worse. In the mid-term period (1985-2000), there will be a transition to non-petroleum fuels, based primarily on shale oil derived liquids assuming a shale oil industry is started during this time.</p> <p>(over)</p>															
17. Key Words and Document Analysis. 17a. Descriptors <table border="0"> <tr> <td>Alternate Fuels</td> <td>Emissions (In Use)</td> </tr> <tr> <td>Marine</td> <td>Energy Efficiency in Production</td> </tr> <tr> <td>Aircraft</td> <td>Resource Requirements</td> </tr> <tr> <td>Pipeline</td> <td>Energy Efficiency in Use</td> </tr> <tr> <td>Railroad</td> <td>Logistics</td> </tr> <tr> <td>Environmental Impact</td> <td>Likert Scale</td> </tr> </table>				Alternate Fuels	Emissions (In Use)	Marine	Energy Efficiency in Production	Aircraft	Resource Requirements	Pipeline	Energy Efficiency in Use	Railroad	Logistics	Environmental Impact	Likert Scale
Alternate Fuels	Emissions (In Use)														
Marine	Energy Efficiency in Production														
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Pipeline	Energy Efficiency in Use														
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16. Abstracts (cont.)

The future outlook for possible prime movers and potential fuel sources for the long term (2000+) is as follows. In the marine area, steam engines burning coal or diesel engines with unrefined shale oil or coal slurries are the prime candidates. With the aircraft gas turbine, either synthetic liquids from shale or coal would appear to be the most desirable fuels. Railroads will probably remain with the diesel/electric prime mover using shale oil as a source of distillate. Pipelines will probably use electric motors as the major type of prime mover.

This Appendix is concerned with the environmental issues in production and use of the fuels, the energy efficiency in use and production, the fuel logistics considerations, and the overall ratings and selection of the fuels and prime movers for the detailed evaluation.

15. ENERGY SUPPLY/DEMAND PROJECTIONS

M. H. Farmer

The Federal Energy Administration Act of 1974 and the Energy Conservation and Production Act of 1976 require that the Energy Information Administration (EIA) (as successor to FEA) prepare forecasts of energy supply and demand and consumption in the short, medium, and long term. The most recent set of forecasts, published in April 1978 and titled "Projections of Energy Supply and Demand and Their Impacts," constituted EIA's annual report to Congress for 1977. The stated objective of the EIA has been to "establish a neutral analytical methodology and to provide alternative energy projections based on assumptions that do not bias the results in a particular policy direction." EIA and other recent energy projections are discussed in this section.

15.1 EIA Projections

The various EIA projections are based on differing assumptions with regard to:

- (1) Economic growth
- (2) Probable levels of recoverable U.S. oil and gas resources
- (3) Changes in the real price of imported oil

Also, to avoid predicting the future course of Government energy policy, EIA assumed "continuation of present energy policy as expressed in existing legislation and actual practice." Thus, the individual projections or "cases" may be considered as a set of "base cases" which would be affected by changes in legislation and energy policy. Put differently, the "base cases" provide a framework within which to consider alternative fuels for NHT systems in an internally consistent way. EIA has striven to achieve internal consistency and has also made the underlying assumptions explicit. It is essential that base case projections of future supply and demand be derived from a common set of assumptions, and also that the assumptions be documented. Then, if a particular assumption is varied, the impact of the change may be traced through the whole system of projection.

The Energy Information Administration's projections, which were published in April 1978, comprised the six "Series" listed in Table 15-1. Series A through E are a partial permutation of three demand assumptions and three supply assumptions, where each variant is combined with the assumption of a constant world oil price. Series F combines an assumption of a higher world oil price with the "medium/medium" demand/supply assumptions (Series C). It is stressed that each of the Series is based on the further assumption of "continuation of present energy policy as expressed in existing legislation and actual practice."

Energy supply/demand balances for 1985 and 1990, for Series A through F, are reproduced in Tables 15-2 and 15-3. Actual statistics for 1975 are included for comparison. Price projections for transportation fuels are given at the bottom of each table. It is stressed that, with the exception of Series F, a constant (1978 \$) world oil price is assumed. This explains

TABLE 15-1
EIA Projection Series

<u>Projection Series</u>	<u>U.S. Demand Assumption</u>	<u>U.S. Supply Assumption</u>	<u>World Oil Price Assumption</u>	<u>Series Characteristic Relative to Constraint Price Assumption</u>
A B	High High	High Low	Constant Constant	Max. Consumption Max. imports and max. relative price of energy
C D	Medium Low	Medium High	Constant Constant	"Mid range" Min. imports and min. relative price of energy
E F	Low Medium	Low Medium	Constant Increasing*	Minimum Consumption Important Contingency

15-2

*Assumed to increase 5%/yr after 1980, such that the 1990 price would be about \$25 per barrel in 1978 constant dollars.

Source: "Projections of Energy Supply and Demand and Their Impacts," page 14, DOE/EIA, April 1978.

TABLE 15-2

1985 Energy Supply/Demand Balance (Quads/yr)

	Actual 1975	1985					
		A	B	C	D	E	F
<u>Domestic Production</u>							
Crude Oil + NGL	20.5	22.5	19.5	21.0	22.5	19.4	21.4
Shale Oil	--	0.2	0.1	0.1	0.2	0.1	0.1
Natural Gas	19.0	19.4	16.0	17.2	19.2	15.6	17.5
Coal	14.6	23.0	23.8	23.1	22.2	22.8	23.6
Nuclear Energy	1.8	6.2	6.2	6.2	6.2	6.2	6.2
Hydro + Geothermal	3.2	4.2	4.2	4.2	4.2	4.2	4.2
Domestic Subtotal	59.1	75.5	69.8	71.8	74.5	68.3	73.0
<u>Imports:</u> Crude Oil	8.7	15.5	19.3	16.5	16.0	17.5	17.0
Pet. Products	3.8	6.6	6.9	6.7	3.2	5.7	4.3
Natural Gas	1.0	1.6	2.1	1.9	1.2	2.0	1.9
Total Supply	72.6	99.2	98.1	96.9	94.9	93.5	96.2
(Less) Exports of Coal	1.8	1.9	1.9	1.9	1.9	1.9	1.9
(Less) Refinery Loss	0.2	0.4	0.4	0.4	0.4	0.4	0.4
Total Domestic Consumption	70.6	96.9	95.8	94.6	92.6	91.2	93.9
<u>Domestic Consumption by Sector</u>							
Industrial	26.0	42.0	41.5	40.7	39.9	39.1	40.9
Commercial	11.3	13.8	13.5	13.5	13.4	13.1	13.2
Residential	14.7	19.3	19.0	19.0	18.9	18.6	18.6
Transportation	18.6	21.8	21.8	21.4	20.4	20.4	21.2
	70.8	96.9	95.8	94.6	92.6	91.2	93.9
<u>Transportation Energy Prices* (1978 \$ per MBTU)</u>							
Gasoline	5.40	5.95	6.01	5.96	5.93	5.99	6.54
Jet Fuel	3.97	4.21	4.27	4.22	4.19	4.24	4.78
Distillate Fuel	4.02	4.80	4.87	4.82	4.80	4.84	5.37
Residual Fuel	2.10	2.98	3.04	2.99	3.03	3.03	3.57

*Prices to final consumer before excise and sales taxes.

Source: EIA report pages 27 and 31 (Tables 2.5 and 2.9).

TABLE 15-3

1990 Energy Supply/Demand Balance (Quads/yr)

	Actual 1975	1990					
		A	B	C	D	E	F
<u>Domestic Production</u>							
Crude Oil + NGL	20.5	23.5	16.0	19.8	23.5	16.0	23.1
Shale Oil	--	0.6	0.4	0.3	0.5	0.3	0.4
Natural Gas	19.0	18.3	13.7	16.7	18.0	13.3	17.4
Coal	14.6	27.7	28.5	27.5	25.3	26.3	29.4
Nuclear Energy	1.8	10.2	10.3	10.3	10.1	10.1	10.4
Hydro + Geothermal	3.2	5.0	5.0	5.0	5.0	5.0	5.0
Domestic Subtotal	59.1	85.3	73.9	79.6	82.4	71.0	85.7
<u>Imports:</u> Crude Oil	8.7	16.7	25.6	20.9	15.0	21.7	15.5
Pet. Products	3.8	7.7	8.0	7.8	5.4	7.8	5.0
Natural Gas	1.0	2.2	2.6	2.6	2.1	2.6	2.5
Total Supply	72.6	111.9	110.1	110.9	104.9	103.1	108.7
(Less) <u>Exports</u> of Coal	1.8	2.1	2.1	2.1	2.1	2.1	2.1
(Less) Refinery Loss	0.2	0.4	0.3	0.3	0.4	0.3	0.4
Total Domestic Consumption	70.6	109.4	107.7	108.5	102.4	100.7	106.2
<u>Domestic Consumption by Sector</u>							
Industrial	26.0	50.0	49.1	49.0	46.2	45.1	48.5
Commercial	11.3	15.0	14.7	15.0	14.4	14.2	14.3
Residential	14.7	21.2	20.9	21.2	20.6	20.4	20.7
Transportation	18.6	23.2	23.0	23.3	21.2	21.0	22.7
	70.6	109.4	107.7	108.5	102.4	100.7	106.2
<u>Transportation Energy Prices* (1978 \$ per MBTU)</u>							
Gasoline	5.40	6.08	6.17	6.14	6.01	6.13	7.62
Jet Fuel	3.97	4.35	4.45	4.39	4.29	4.38	5.87
Distillate Fuel	4.02	4.94	5.04	5.00	4.88	4.98	6.39
Residual Fuel	2.10	3.11	3.24	3.16	3.09	3.17	4.52

ces to final consumer before excise and sales taxes.

ce: EIA report pages 28 and 32 (Tables 2.6 and 2.10).

the relatively small transportation fuel price increases in 1985 and 1990, over actual 1975 levels. Even for Series F, the projected price increases for 1985 and 1990 are not large*:

	% Increase Over 1975	
	1985	1990
gasoline	21	41
jet fuel	20	48
distillate fuel	34	49
residual fuel	70	115

The assumption of balance between supply and demand is also an implicit assumption of no shortage on a current basis. However, the assumption of a 5%/yr. escalation in the constant dollar world oil price could be interpreted as a response to a perception of impending or foreseeable shortage.

The assumption of a smooth, exponential increase in the real price of a commodity is convenient for illustrative purposes, but has almost no likelihood of occurring. An irregular, cyclical pattern is more likely, even for a non-renewable resource. For example, a sharp price increase would be expected to act as a demand constraint, at least temporarily. The consequent lower demand would be expected to bring about a surplus of supply, at least temporarily. In these circumstances, further near term price increases would be unlikely and, under conditions of inflation (stimulated by the initial sharp price increase), the nominal price would probably erode on a constant dollar basis**.

Additional price information, both historical and Series C projections, from the EIA report is reproduced in Table 15-4. Price erosion, on a constant dollar basis, may be noted for the 1960/72 period. In fact, the erosion began prior to 1960 and is often cited now as a factor that contributed to general lack of concern for energy conservation prior to 1973.

Comparisons of 1975/85 and 1985/90 projections of energy consumption and price behavior for the transportation sector and total domestic energy are given in Table 15-5. The following trends are observed:

(1) energy consumption

- projected growth rates are lower for the 1985/90 period than for 1975/85
- projected growth rates are lower for the transportation sector than for total domestic energy consumption in both time periods

*By comparison with the increases that occurred in 1974.

**This is what has happened to the world price of oil since the sharp price increases of 1973/74. It is not necessarily a good guide to what may happen in the future. Different response patterns might be expected for (a) a production limitation (imposed by producers), and (b) a producibility limitation (imposed by nature, i.e. by resource limitations).

TABLE 15-4

Comparison of Historical Growth Rates for Energy Prices
Compared with Rates Projected for Series C

	<u>Annual Growth Rate, Constant \$ Basis</u>			
	<u>1960/72</u>	<u>1972/75</u>	<u>1975/85</u>	<u>1985/90</u>
Period in Years	(12)	(3)	(10)	(5)
Electricity	-2.2	4.7	2.0	0.6
Natural Gas	0.3	9.2	5.7	4.1
Distillate Fuel	-0.5	14.1	2.2	0.5
Residual Fuel	-0.3	28.0	3.4	0.3
LPG	-1.0	15.2	3.2	Nil

Source: EIA report page 90 (Table 5.1).

TABLE 15-5

Comparison of 1975/85 and 1985/90 Projections of Consumption and Price Behavior for Transportation Sector and Total Domestic Energy

		Annual Growth Rates, %					
		<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>	<u>F</u>
<u>Energy Consumption</u>							
(1) 1975/1985							
Transportation Sector		1.6	1.6	1.4	0.9	0.9	1.2
Total Domestic Energy		2.8	2.7	2.6	2.3	2.2	2.4
(2) 1985/1990							
Transportation Sector		1.2	1.1	1.7	0.8	0.6	1.4
Total Domestic Energy		2.0	2.0	2.4	1.6	1.6	1.9
<u>Price Change (Constant \$ Basis)</u>							
(1) 1975/1985							
Transportation Sector		1.2	1.3	1.2	1.1	1.2	2.2
Total Domestic Energy		2.3	2.7	2.5	2.2	2.6	3.4
(2) 1985/1990							
Transportation Sector		0.6	0.7	0.7	0.4	0.5	3.2
Total Domestic Energy		1.2	1.3	1.5	1.1	1.1	3.2

Source: EIA report pages 91 and 92 (Tables 5.3 and 5.5).

(2) price change

- except for Series F, price changes are slower in the later time period
- except for Series F, price changes for the transportation sector are only about half of the corresponding changes for total domestic energy

The price change projections are questionable* on several counts:

- If petroleum resources become seriously constrained before the year 2000, it would be expected that the perception of forthcoming shortage would be stronger during the 1985/90 period than during 1975/85.
- A sharpening perception of shortage is inconsistent with a declining rate of price increase.
- If the transportation sector effects were backed out of total domestic energy, the differential between the transportation sector and the other three sectors (industrial, commercial, residential) would be more marked as shown below:

Annual Price Change, %, for 1985/90 Period

	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>	<u>F</u>
transportation	0.6	0.7	0.7	0.4	0.5	3.2
industrial	1.6	1.8	5.7**	1.5	1.6	4.0
commercial	2.4	2.0	2.2	2.3	2.0	3.3
residential	2.4	2.2	2.5	2.3	2.1	3.4

- The projections of much more rapid price increases for the industrial sector than for the transportation sector have potentially negative implications for alternate fuels, since the cost of industrial energy would be a factor in the cost of manufacturing the capital goods required for the production of alternate fuels. The annual percentage price changes imply the following cumulative percentage changes over the 5-year period (1985/90):

Percent Change in Price (1990 - 1985)

	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>	<u>F</u>
transportation	3.0	3.5	3.5	2.0	2.5	17.1
industrial	8.3	9.3	31.9	7.7	8.3	21.7

*It is recognized that the projections depend on the assumptions associated with EIA's "neutral analytical methodology" and do not constitute a forecast of what is expected to happen.

**This number is accurately copied from Table 5-5 of EIA's report, but seems questionable.

- The 5-year differential percentage between the transportation and industrial sectors is least for Series F. Thus, on a relative basis, the projections are consistent with the generally held view that higher world oil prices would improve the competitive position of alternate fuels. However, the point could be made with more conviction if the baseline transportation energy prices were increasing more rapidly than the baseline industrial energy prices.*

In addition to the reference cases (Series A through F), and to the statistical projections reviewed above, EIA's study takes specific account of the impact of new and emerging technologies. Pertinent projections are reviewed in Table 15-6. The last line of this Table expresses the energy content of liquid fuels produced by the new technologies as percentages of the total energy so produced. The percentages, which range from 16-17% in 1985 to 19-24% in 1990, may be compared with the current figure of 50% of total domestic energy consumption in the form of liquid fuels. Put differently, the projected increments in liquid fuel supplies derivable from new and emerging technologies--even with "heavy government intervention"-- are considerably less than required to sustain the present pattern of domestic energy usage. Hence, one inference (as drawn on page 33 of the EIA report) is that "substantial adjustments in patterns of consumption will take place". Such adjustments would not be limited to the transportation sector. Indeed, displacement of oil from the industrial sector*** to transportation is a common expectation. However, shifts within the transportation sector are possible too, including shifts within the non-highway sub-sectors. The breakdown of transportation energy use in 1976 is shown in Table 15-7.

Although EIA's own projections had a terminal year of 1990, recent projections by others are reviewed in the report (15-2, 15-3, 15-4). A comparison of these projections, which extend to the year 2000, is given in Table 15-8. For illustrative purposes, we will assume that 20% of total domestic energy consumption is for transportation purposes in the year 2000****. In Table 15-9, this assumption leads to the inference that as much as 51% to 67% of total domestic oil consumption could be for transportation purposes, unless fuels other than oil were used*****. Currently, transportation accounts for about 40% of U.S. oil consumption. Hence, a considerable shift in consumption patterns is implied by Table 15-9, but no obvious infeasibility is evident. A different light is cast on the matter in Table 5-10, where the assumed transportation energy consumption is related to the projected supply of domestically-produced oil. It is apparent that the postulated transportation energy needs could not be met without drastic changes in fuels used and/or very considerable imports of liquid fuels. The purpose of the final columns in Table 15-10 is to indicate that the inferences just drawn would have been less obvious if consideration had been limited to non-highway transportation fuels.

*Resolution of this issue is beyond the scope of the present study. The EIA projections are derived from DOE's (formerly FEA's) Project Independence Evaluation System computer model. Hence, resolution of the issue might be both difficult and technically complex.

**EIA report page 229.

***Including electricity generation by utilities.

****The statistic for 1975 was 26.3%. EIA's six cases range from 22.0% to 22.8% for 1985 with a mean of 22.5%, and from 20.8% to 21.5% for 1990 with a mean of 21.2%. Extrapolation to the year 2000 gives a value of about 20%.

*****In 1976 oil accounted for 96.9% of transportation fuel usage.

TABLE 15-6

Production Projections for New and Emerging Technologies

	<u>1985 (Quads)</u>		<u>1990 (Quads)</u>	
	<u>Reference*</u>	<u>Upper Bound**</u>	<u>Reference*</u>	<u>Upper Bound**</u>
<u>Synthetic Gases</u>				
High BTU	0.10	0.15	0.23	0.45
Low BTU	<u>Nil</u>	<u>0.05</u>	<u>0.07</u>	<u>0.20</u>
	0.10	0.20	0.30	0.65
<u>Synthetic Liquids</u>				
Shale Oil	0.10	0.20	0.35	0.55
Coal Syncrude	<u>Nil</u>	<u>Nil</u>	<u>0.05</u>	<u>0.15</u>
	0.10	0.20	0.40	0.70
Geothermal Energy	0.30	0.60	0.70	1.30
Solar Heating and Cooling	0.068	0.149	0.144	0.257
Solar Electric Energy	Nil	0.002	0.002	0.03
Wind Energy	<u>0.01</u>	<u>0.09</u>	<u>0.11</u>	<u>0.66</u>
	0.08	0.24	0.26	0.95
TOTAL	0.58	1.24	1.66	3.60
Liquid Fuels as % of Total ^Ø	17	16	24	19

*Applies to Series A through F.

**"Assumes heavy government intervention."

^Ø Liquid fuels account for 50% of current (1978) domestic energy demand.

Source: EIA report page 229 (Table 11.1).

TABLE 15-7Breakdown of Transportation Energy Use in 1976

	<u>Percent of Total Transportation Fuel Consumption</u>
<u>Highway</u>	
Automobile and Motorcycle	53.4
Truck	23.2
Bus	0.7
	<u>77.3</u>
<u>Non-Highway</u>	
Air	8.0
Marine (purchased in U.S.)	4.6
Rail	3.6
Pipeline	3.9
Other	2.6
	<u>22.7</u>

Source: EIA report page 110 (Table 5.23).

TABLE 15-8

Comparison of Recent "Year 2000" Projections of U.S. Energy Consumption

	BNL/DJA Base	SRI		WAES			
		Base	Low	C1	C2	D7	D8
<u>GNP Growth, %/yr</u>							
1975/1985	3.6	4.6	2.8	4.4	4.4	3.2	3.2
1985/2000	3.0	2.9	1.7	3.5	3.5	2.5	2.5
<u>Technology Emphasized in 1985/2000 Period</u>							
	Coal + Conservation	Coal	Coal	Coal	Nuclear	Coal	Nuclear
<u>Crude Oil, 1975 \$/bbl*</u>							
1975/1985	13.00	14.09	12.82	13.00	13.00	13.00	13.00
1985/2000	15.09	17.86	15.54	18.75	18.75	13.00	13.00
<u>Domestic Consumption (Quads)</u>							
Domestic Oil	18.8	23.5	17.9	14.9	14.9	12.7	12.7
Shale Oil	3.0	0.6	0.2	4.2	4.2	--	--
Imported Oil	26.9	14.9	14.9	19.9	20.5	32.2	32.3
Oil Subtotal	48.7	49.0	33.0	39.0	39.6	44.9	45.0
Domestic Gas	17.7	20.1	15.7	14.0	14.0	11.5	11.5
Imported Gas	1.3	2.6	3.1	3.0	3.6	5.0	5.0
Coal	32.6	43.8	29.0	29.8	27.1	21.1	19.1
Solar/Biomass	3.9	2.3	1.8	3.9	3.9	1.7	1.7
Other	--	--	--	1.0	1.0	--	--
Hydro/Geothermal	5.8	3.8	3.8	4.6	4.6	3.7	3.7
Nuclear Energy	28.5	31.6	23.0	26.0	35.2	26.0	33.1
TOTAL	138.5	143.2	109.4	124.3	132.0	115.1	120.3
Oil Subtotal as % of Total	35	34	30	31	30	39	37

Source: EIA report pages 35 and 36 (Tables 2.11 and 2.12).

TABLE 15-9

Transportation Energy Implications of "Year 2000" Projections

<u>Source of "Year 2000"</u> <u>Projection</u>	(1) Total Domestic Energy Consumption 10 ¹⁵ BTU (Quads)	(2) Oil Consumption Subtotal (Quads)	(3) Transportation Consumption* (Quads)	Column (3) as % of Column (2)
BNL/DJA Base	138.5	48.7	27.7	57
SRI - Base	143.2	49.0	28.6	58
- Low	109.4	33.0	21.9	66
WAES - C1	124.3	39.0	24.9	64
- C2	132.0	39.6	26.4	67
- D7	115.1	44.9	23.0	51
- D8	120.3	45.0	24.1	54

*Assumed to be 20% of total domestic energy consumption.

Source: Table 15-8 and References 15-2, 15-3, and 15-4.

TABLE 15-10

Comparison of Transportation Energy Consumption with Projected
Supply of Domestically-Produced Liquid Fuels

<u>Source of "Year 2000" Projection</u>	<u>(1) Domestically-Produced Liquid Fuels 10¹⁵ BTU (Quads)</u>	<u>(2) Transportation Consumption* (Quads)</u>	<u>Column (2) as % of Column (1)</u>	<u>(3) Non-Highway Transportation Consumption** (Quads)</u>	<u>Column (3) as % of Column (1)</u>
BNL/DJA Base	21.8	27.7	128	9.2	42
SRI - Base	24.1	28.6	119	9.5	39
- Low	18.1	21.9	121	7.3	40
WAES - C1	19.1	24.9	130	8.3	43
- C2	19.1	26.4	138	8.8	46
- D7	12.7	23.0	181	7.7	61
- D8	12.7	24.1	190	8.0	63

*Assumed to be 20% of total domestic energy consumption.

**Assumed to be 33% of total transportation consumption.

Source: Tables 15-8 and 15-9.

The EIA report does not provide a detailed breakdown by transportation mode and fuel type within the transportation sector. However, this has been covered in DOE's "Transportation Energy Conservation Data Book," as discussed below.

15.2 Transportation Energy Conservation (TEC) Projections

The first and second editions of the TEC Data Book were published, respectively, in October 1976 and October 1977 (15-6,15-7). These extensive compilations of data include "year 2000" and other projections. Two such projections are reproduced in Tables 15-11 and 15-12. The latter table also contains projections from a 1978 up-date of the TEC Data Book*. Differences between the 1978 and 1977 projections are minor for the non-highway transportation modes. In fact, the only major change is for fuel used by automobiles. In this case, the 1978 projections for 1985 and 2000 are mid-way between those made in 1976 and in 1977. As shown in Table 15-13, the 1977 projections of future transportation energy demand were lower than those made a year earlier. In both years, separate projections were made using a variety of conservation assumptions. A comparison of the conservation cases is given in Table 15-14.

It is not surprising that there should be numerical differences between the projections published in 1976 and 1977, and the matter is mentioned in support of the view that no useful purpose is served by over-concern with precise numerical quantification of the more distant future. It is not the future (in 1985 and 2000) that has changed but "our" perceptions of this future from the vantage points of 1976, 1977 and 1978. This is true of the base cases (without conservation) and of the conservation projections. Moreover, the perception of what may be achieved by conservation also changed from 1976 to 1977, as shown below:

<u>% Difference between Non-Conservation and Conservation Cases of Transportation Energy Demand</u>		
<u>Projection</u>	<u>1985</u>	<u>2000</u>
TEC-76	13	25
TEC-77	5	31

The pattern of the above changes is consistent with commonly observed forecasting behavior:

- As the nearer year (1985) is approached, the perception of what may be achieved by additional changes decreases.
- As the additional potential perceived for the nearer year becomes small on an absolute basis, and if the perceived need for additional change is sustained, more drastic measures may be considered for the later year with the consequence that the revised perception is of a greater potential for change in the longer term.

*TEC-78 has not been printed yet. However, pertinent statistics in Table 15-12 were made available by the Non-Highway Transportation Systems Branch in the interest of making this study as current as possible.

TABLE 15-11

ERDA-48 Demand Forecast for Transportation Fuels

	<u>10¹⁵ BTU (Quads)</u>	
	<u>1985</u>	<u>2000</u>
Automobiles	10.46	12.84
Trucks and Buses	5.49	7.93
Highway Subtotal	<u>15.95</u>	<u>20.77</u>
Air	4.70	8.63
Marine	1.17	1.62
Railroad	0.73	0.99
Pipeline	1.26	1.88
Non-Highway Subtotal	<u>7.86</u>	<u>13.12</u>
TOTAL	<u>23.81</u>	<u>33.89</u>

Source: TEC Data Book, 1st Edition, ORNL 5198, October 1976.

TABLE 15-12

Baseline Transportation Energy Demand (Before ERDA Conservation Program)

	<u>10¹⁵ BTU (Quads)*</u>		<u>10¹⁵ BTU (Quads)**</u>	
	<u>1985</u>	<u>2000</u>	<u>1985</u>	<u>2000</u>
Automobiles	7.91	8.80	9.4	10.9
Personal Trucks	1.25	1.58	} 5.3	} 7.6
Other Trucks	3.80	6.04		
Buses	0.13	0.22	0.1	0.2
Highway Subtotal	<u>13.09</u>	<u>16.64</u>	<u>14.8</u>	<u>18.7</u>
Air	2.50	4.40	2.5	4.4
Marine	1.15	1.50	1.1	1.5
Railroad	0.67	1.00	0.7	1.2
Pipeline	1.28	1.50	1.4	1.3
Other (military, gen. aviation)	1.34	1.51	1.2	1.2
Non-Highway Subtotal	<u>6.94</u>	<u>9.91</u>	<u>6.9</u>	<u>9.6</u>
TOTAL	<u>20.03</u>	<u>26.55</u>	<u>21.7</u>	<u>28.3</u>

Sources: *TEC Data Book, 2nd Edition, ORNL 5320, October 1977.
 **Letter of November 1978, with numbers to be
 in TEC-78.

TABLE 15-13

Comparison of TEC Data Book Projections
Published in Oct. 1976 and Oct. 1977

	10 ¹⁵ BTU (Quads)			
	TEC-76	TEC-77	77/76 Δ	Δ%
• 1985				
Highway	15.95	13.09	-2.86	-18
Non-Highway	7.86	6.94	-0.92	-12
	23.81 ^ø	20.03	-3.78	-16
• 2000				
Highway	20.77	16.64	-4.13	-20
Non-Highway	13.12	9.91	-3.21	-24
	33.89 ^ø	26.55	-7.34	-22

^øAdjusted ERDA-48 totals for 1985 and 2000 were 22.8 quads and 32.3 quads respectively.

TABLE 15-14

Comparison of TEC-76 and TEC-77 Conservation Cases

Total Transportation Sector Demand	10 ¹⁵ BTU (Quads)			
	TEC-76	TEC-77	77/76 Δ	Δ%
1985	20.6	19.1	-1.5	-7
2000	25.3	18.3	-7.0	-28

These observations concern normal forecasting behavior, which the reader is asked to keep in mind when considering the following discussion of the relationship of the TEC projections to those of EIA et al. Before beginning this discussion, two further observations will be made:

- (1) Currently, non-highway transportation accounts for about 23% of the transportation sector's total energy consumption. TEC-76 projected an increase to 33% in 1985 and 39% in 2000, while TEC-77 projected 35% and 37% for the same years. The principal factors affecting this percentage are the consumption of (a) motor gasoline (highway fuel), and (b) aviation jet fuel (non-highway fuel). For example, effective conservation of motor gasoline together with expansion of air traffic would result in an increased percentage of non-highway fuel usage.
- (2) TEC-77's conservation case projects a lower consumption of transportation energy in the year 2000 (18.3 quads) than in 1985 (19.1 quads). This case projects a peaking of the sector's energy consumption in 1985. Hence, the TEC-77 base and conservation cases diverge steadily.

TEC-77, TEC-78 and EIA projections for the energy consumption of the transportation sector are compared in Table 15-15. Except for TEC-77's conservation case, all of the projections for 1985 are clustered in the range of 20.0 to 21.8 quads. This is not particularly surprising since all of the projections are for base cases and the time until 1985 is insufficient for large changes to occur -- except as the consequence of the type of exogenous event that is specifically excluded by the assumptions used to generate the projections. The scatter is somewhat greater for the year 2000. Here, the TEC-77 base case (26.6 quads) is intermediate between EIA's Series F (26.0 quads) and Series C (27.6 quads)*, while TEC-78 provides the nominally highest projection (28.3 quads). It will be recalled that both F and C are "medium/medium" with respect to overall supply and demand assumptions but, for F, the world price of crude oil was assumed to increase by 5% per year in real terms after 1980. As modeled, this price assumption has a relatively insignificant impact (a reduction of only 6%) on the energy consumption of the transportation sector. Except for the TEC-77 conservation case (18.3 quads), the lowest projection is for Series E (22.3 quads). At first sight, this may be surprising since E combines low overall demand and supply assumptions. However, the explanation, at least in part, is that "supply" refers to domestic supply and any deficit in oil is made up with imported petroleum that is assumed to have a constant price in 1978 dollars. It may seem unreasonable to continue this price assumption from 1990 to the year 2000. If so, the inference may also be drawn that assumption of a constant world oil price until 1990 may be unreasonable. Yet, the Series C and F results suggest that transportation energy demand is not very sensitive to world oil price (as modeled by PIES). This leads to the simplistically obvious conclusion that transportation energy consumption must be sensitive

*All of the EIA Series were extrapolated from the pertinent 1985 and 1990 projections.

TABLE 15-15

Comparison of TEC-77 Energy Consumption Projections with EIA Series

	TEC-77		TEC-78**	EIA Series*					
	Base	Conserve	Base	A	B	C	D	E	F
1985 (Quads)	20.03	19.1	21.7	21.8	21.8	21.4	20.4	20.4	21.2
2000* (Quads)	26.55	18.3	28.3	26.3	25.6	27.6	22.9	22.3	26.0
2000/1985 Increment (Quads)	6.52	-0.8	6.6	4.5	3.8	6.2	2.5	1.9	4.8
Increment, %	33	-4	23	21	17	29	12	9	23

*Extrapolated from 1985 and 1990 values in Table 15-2 and 15-3.

**DOE letter of November 1978, with numbers to be included in TEC-78.

to supply; i.e. consumption and consumption patterns may be strongly influenced by actual shortages of supply or by perceptions of shortage in the absence of avertive actions. This is the conceptual basis of the TEC-77 conservation case.

It is also possible to compare what may be achievable by conservation with what has been projected, on the supply side, for "new and emerging technologies". To do this, we took the "upper bound" numbers for shale oil from Table 15-6 and applied the 1985/90 growth rate of 18%/yr to the 1990 synthetic liquids total of 0.70 quads to obtain a year 2000 extrapolation of 3.6 quads. This is a very optimistic (i.e. unlikely) extrapolation. The purpose is to make a comparison, on a similar "maximum efforts" basis, with the 8.3 quads differential in the year 2000 projections for the TEC-77 conservation and base cases. In spite of the imprecision of these numbers, two qualitative conclusions may be drawn:

- (1) initiatives for conservation and production of liquid fuels by new technologies both appear important.
- (2) definitely in the near-term (until 1985) and probably in the mid-term (from 1985 to 2000) conservation may be quantitatively more important than what may be achieved by new supply technologies.

Intuitively, we believe that the long-term downtrend in total transportation energy demand represented by the TEC-77 conservation case is not sustainable, i.e. at some time in the future, absolute demand would begin to trend upward again. If so, supplies derived from new technologies would become essential. In view of the extremely long lead-time of these technologies, as manifest by an "upper bound" of 3.6 quads in year 2000, conclusion (1) above is reinforced. It is precisely because of the long lead-time that the supply initiatives seem important now, thereby complementing conservation initiatives that can produce results sooner but finitely.

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16. MILITARY AND INTERNATIONAL CONSIDERATIONS

M. H. Farmer

Historically, the military fuel requirements of the U.S. have been procured both domestically and overseas. However, there are legislative and other provisions that make it clear that, in an emergency, military needs would have priority over many domestic civilian uses of fuel. Moreover, some level of military priority can apply even under "normal" conditions because of the need to maintain defense capabilities in the interest of national security. The latter has been broadly interpreted. For example, Section 232(c) of the Trade Expansion Act of 1962(8) recognizes "the close relation of the economic welfare of the Nation to our national security." Section 232(c) contains wording of possible applicability to all types and sources of fuel; pertinent citations follow.

"...the Director* and the President shall, in the light of requirements of national security and without excluding other relevant factors, give consideration to domestic production needed for projected national defense requirements."

"...the requirements of growth of such industries** and such supplies and services including the investment, exploration, and development necessary to assure such growth..."

It should be pointed out that Section 232 was the statutory foundation of the former Mandatory Oil Import Program⁽¹⁶⁻¹⁾. While MOIP itself has been terminated and oil import quotas have been abolished, some of the conditions that prompted the program still exist. Indeed, Government funding of the development of alternative fuels technology is premised by concern for the future dependability and availability of petroleum imports. Thus, while many other factors are involved, national security is a unifying issue in the military and international considerations discussed below.

16.1 Military Considerations

Currently, DOD's consumption of energy, including electricity, is equivalent to about 2% of U.S. energy demand. While the aggregate percentage is small, military demand is concentrated in a small number of products. About 62% of military demand is for transportation fuels and the rest for stationary sources:

	<u>% of Total Demand</u>
Transportation: Aircraft	44
Marine	13
Ground	5
	<u>62</u>
Stationary Sources	38
	<u>100</u>

*Director of the Office of Emergency Planning (later, the Office of Emergency Preparedness).

**Needed to sustain national defense requirements.

At present, the transportation fuels are derived entirely from petroleum while the stationary requirements are supplied from various sources:

<u>Energy/Fuel Source</u>	<u>% of Total Demand</u>
Petroleum liquids	67
LNG/LPG (petroleum)	7
Coal	3
Electricity	20
Other	3
	<u>100</u>

With specific exceptions (e.g. nuclear submarines and aircraft carriers), DOD's transportation fuel strategy has moved toward logistical simplicity: aircraft jet fuel and diesel fuel (which doubles as boiler fuel). The logistical practicality of this "two fuel" strategy does not imply a lack of technical interest in other types of fuel or fuel compositions, but it does mean that actual deployment of a variety of fuel types is unlikely. Put differently, a decision to deploy a new fuel would probably be paralleled by a decision to substitute the new fuel throughout the entire DOD system. Such a decision is unlikely unless the new fuel were to permit superior combat performance.

Only in the case of aviation jet fuels is military demand a significant fraction of total demand for aviation fuels. This fact has two important implications:

- (1) Military and civilian aircraft utilize the same fraction of the "petroleum barrel."
- (2) In an emergency, military jet fuel needs could be met by curtailment of civilian demand.

Potentially, there is a conflict between (1) and (2) because relief of a future supply constraint (item 1) through development of different fuels for military and civilian purposes could impair substitutability (item 2). The point may be illustrated by a technically possible, but unlikely, example. Let us hypothesize* the following:

- (1) DOD sponsors the conversion of raw shale oil into jet and diesel fuels.
- (2) The jet fuel derived from shale oil is not identical to conventional jet fuel.
- (3) DOD equipment (i.e. aircraft) is modified to obtain optimal performance from the shale-derived jet fuel.
- (4) The modified DOD equipment does not permit optimal performance on conventional jet fuel.

*The assumptions are not projections, and are made solely for the purpose of illustrating the substitutability issue.

The hypothetical outcome appears unsatisfactory since it implies one or more of the following consequences:

- DOD jet fuel supply becomes tied to shale oil production.
- Some DOD equipment performs suboptimally if forced to use jet fuel other than that derived from shale oil.
- Some DOD equipment uses shale-derived jet fuel while other DOD equipment uses fuel (of different quality) derived from other resources thereby violating logistical simplicity.

Another example will illustrate the hypothetical consequences of development of novel fuels for civilian aircraft. What is hypothesized is extremely unrealistic, and the purpose of the example is to illustrate why this is so. We hypothesize the following:

- (1) In anticipation of an eventual shortage of conventional (paraffinic) aviation fuels, programs are undertaken to develop engines (and aircraft) capable of using blends of alcohols and aromatic hydrocarbons.
- (2) The volumetric heat content of the blends is lower than that of conventional jet fuels but, technically, the new fuel/engine system is operable.
- (3) Incentives are provided to induce deployment of the new fuel/engine system (thereby substituting the new fuel blends for conventional jet fuels and "saving" the latter for other uses).
- (4) With the new system in place it would no longer be possible, in time of emergency, to augment supplies of military jet fuels by simple curtailment of civilian demand.

The foregoing discussion may be summarized in the form of two expectations:

- DOD may adopt a unique fuel system if this produces a unique performance advantage.
- Most of DOD's transportation fuel needs will continue to be met with conventional types of jet and diesel fuel.

Additional information about DOD's transportation fuel activities is summarized in Table 16-1.

DOD maintains bases, personnel and equipment in many parts of the world. Some of this activity is in the form of multilateral commands such as NATO. Such overseas operations are constrained logistically. For example, supplies will be procured from a variety of sources and must be mutually compatible. In addition, changes to fuels and equipment will usually be agreed multilaterally. Moreover, equipment based in the U.S. that may be deployed overseas may also have to be

TABLE 16-1Summary of DOD Transportation Fuel Activities

- No significant changes in fuel quality are anticipated except, eventually, greater thermal stability in fuels for high MACH Number aircraft.
- The purposes of current oil shale activities are to:
 - (1) provide a higher degree of assurance that fossil fuels will continue to be available in the future
 - (2) determine the probable characteristics of fuels derived from shale oil and what they should be to match the needs of DOD equipment (and, if necessary, how the equipment might be modified to insure a good match).
- Shale-derived fuels are being produced for testing and characterization. DOD relies on industry for the technology and capability of producing and refining the pertinent fuels.
- Emphasis on shale-derived fuels is based on the judgment that such fuels are likely to be better suited to DOD needs than coal-derived liquids.
- A cooperative project with DOE is probable. In this case, DOE would sponsor the production and refining of about 100,000 barrels of shale-derived fuels while DOD would commit funds to the evaluation and testing of the fuel products.
- DOD does not intend to utilize alcohol fuels because of expected high cost and limited availability. (The alcohol fermentation unit at the Army's NATICK Laboratory is now funded by DOE.)
- No DOD effort is planned on coal-in-oil slurries, beyond monitoring of possible commercial developments.
- In non-transportation areas, DOD is making technical efforts of varying size in the use of biomass as a boiler fuel, photovoltaics, solar heating and cooling, fuel cells, geothermal energy, and wind energy.
- The breakdown of current petroleum usage is:

Aircraft fuels	65%
Marine fuels	16%
Ground "	8%
Stationary Sources	11%
- The breakdown of petroleum use by service is:

Air Force	48%
Navy	31%
Army	18%
Marine Corps	3%
- Long term storage stability is an important quality for DOD fuels.

compatible with fuels available overseas. Clearly, these considerations require a high degree of standardization, i.e. the avoidance of incompatible systems. This is another reason for anticipating that changes in fuel quality are likely to be both small and incremental. With a greater margin of flexibility, similar considerations apply to commercial transportation systems.

16.2 International Considerations

Competition is a particularly important factor in international markets. While competition has many forms, cost, reliability, and availability of product or service are usually parts of its cutting-edge. However, these elements may be blunted to varying degrees by regulations that, in addition to establishing international standards, tend to limit the rate at which changes can occur. This applies to changes that can not be put into effect without the approval of all parties (or, at least, a majority) to a particular international agreement. Clearly, approval is unlikely if a change would advantage one party while disadvantaging* others. The air transportation situation will be discussed first.

16.2.1 Air Transportation System

The word "system" may be applied to air transportation in several different senses, e.g.:

- The component parts of a given aircraft (engines, wings, airframe, etc.).
- A family of aircraft derivable from a "basic" model.
- An airlines fleet and the incorporation of new aircraft into the fleet.

Each of these "systems" has characteristics that affect competitive behavior, e.g.:

- The cost of developing and introducing a new system has become very large.
- The rewards for commercial success are commensurately large.
- The useful life of a given system is considerable, e.g. 20 years or more.

Thus, competition in the aircraft business is for very high stakes at relatively infrequent intervals.** The pattern of competition has been changing from along international (hence, political) lines to among trans-national consortia of companies. In such cases, the different

*In the sense of comparative, or competitive, disadvantage.

**Relative, for example, to automobile and many other manufacturing activities where market share may ebb and flow on an annual basis and where competitive opportunities are always present.

components of a new aircraft system may be manufactured by different companies in different countries, and final assembly may be in more than one country. Recent emphasis has been on the cost and performance of competing systems, and on related issues such as financing and credit terms. The only way in which fuel has figured in competitive evaluations is in terms of fuel economy. With one exception, all of the entirely new and derivative aircraft have been designed for fuel economy. The exception, the British/French SST, has garnered some technological and other forms of prestige but is not representative of the main thrusts of present commercial developments. The prevailing trends are to high load factor and fuel-efficient operations. New aircraft delivered in the 1980's, and probably into the 1990's, will reflect these trends since long range purchase contracts are being negotiated and some have already been concluded. The following citation from a paper presented at a recent technical conference captures the essence of what one airline (Pan Am) is trying to accomplish (16-2).

"The most rewarding way to increase fuel efficiency is to increase the seating capacity of the airplane, and then put more bodies in the seats, or more cargo in the cargo compartments. Virtually all airlines have increased seating capacities in their airplanes, either by reducing First Class seats and devoting more space to Economy seats, or by increasing the density of Economy seating. However, while this may improve fuel efficiency in terms of seat (or ton) miles per gallon, it does not necessarily decrease total gallons consumed. On the contrary, with the increase in loads resulting from the marked decrease in fares, total airline consumption undoubtedly will increase."

The conclusions of the same paper make three references to fuel quality:

- (1) "Use of new fuels such as methane or hydrogen appears quite remote; the ground handling problem is of greatest concern."
- (2) "If broader based specification fuels are to be used, some preference is expressed for lower volatility fuels."
- (3) "The turbine engine appears reasonably tolerant to alternative fuels, but caution is expressed regarding effects on operating temperatures of hot parts."

In amplification of (1), it was pointed out that airlines would wish to refuel a given aircraft at twenty to thirty different airports--all of which would need liquid hydrogen facilities. Liquid methane would be easier to handle, and it would be easier to introduce this fuel into normal service. In relation to (2), it is recognized that a broad cut fuel would make more fuel available*, but this might be a backward step with respect

*Fuel availability would increase with respect to yield of aircraft fuel per barrel of crude oil, but only at the expense of reducing the yield of other products. In a situation of general shortage of petroleum, there would be a need to consider end-use priorities in addition to yield patterns.

to safety and emissions. Concerning (3), it was stated that higher aromaticity would lead to higher maintenance cost. Inverting this point, and applying it to jet fuels derivable from coal, it appears that a high degree of hydrogenation would produce fuels giving rise to minimum maintenance costs. However, there would be a trade-off in cost between hydrogenation (during fuel processing) and maintenance (associated with aircraft operation).

Another aspect of maintenance is the frequency with which engine parts are replaced such that, in effect, an engine may be completely replaced within a period of five years or less. In principle, this would permit small, incremental changes to be made to both fuels and engines. Operationally, this form of "dynamic optimization" would require careful planning and cooperation among airlines (since it would not seem practical to supply a different quality of fuel to each).

Some of the observations made for air transportation also apply to marine and railroad activities. In each case, the goal is to provide transportation of people or freight as economically as possible. The introduction of new fuels is not a goal of companies providing transportation services. A general conclusion may be inferred from this fact: any alternate fuel with properties similar to those of the fuel currently used, which will also minimize the capital requirements and operating expenses of the fuel user, will be preferred to an alternate fuel that is dissimilar, thereby causing additional capital expense and handling problems.

16.2.2 Marine Transportation System

Marine transportation is concerned, almost entirely, with the movement of goods (as distinct from air transportation, which is primarily concerned with moving people). With some exceptions, e.g. container ships and movements covered by the Jones Act, U. S. flag vessels do not compete effectively with foreign flag vessels. This fact is of great concern to the Maritime Administration of the U. S. Department of Commerce. Accordingly, MARAD has been and is seeking ways to improve the future situation of both U. S. shipbuilders and U. S. flag vessels. For example, MARAD is trying to identify specific future marine transportation needs and the pertinent technology that could be developed to improve the competitive position and productivity of the U. S. shipping industry. Under these circumstances, and considering the worldwide surplus of most forms of marine transportation capacity, it seems probable that fuel quality will continue to be dominated by system costs, i.e.: cost of fuel, cost of maintenance, and cost of new capital investment. Thus, any "new" fuel that would not minimize the aggregate of these three elements of cost is certain to be resisted by both the U. S. and foreign shipping industries.

The still growing surplus of maritime transportation capacity is evidenced by the shipbuilding statistics in Table 16-2 and by the following statement from "The Economist" of London(16-3,16-4):

"The EEC has tried (and failed) to allocate cuts in shipbuilding capacity among its members. But the OECD's Working Party 6 is providing a forum for the Japanese and Europeans to confront/consult each other (the Americans do not take part). Its success has been modest: it has not achieved any agreed carve-up of the dwindling market, nor prevented rival national subsidy schemes in what is left."

TABLE 16-2

Decline in Shipbuilding Activity by OECD* Members

Million Compensated Gross Registered Tons

	<u>Ships Completed</u>					<u>Scheduled Delivery**</u>	
	<u>1974</u>	<u>1975</u>	<u>1976</u>	<u>1977</u>	<u>1978</u>	<u>1979</u>	<u>1980</u>
EEC***	4.1	5.0	5.0	4.0	4.3	1.7	0.4
Other W. Europe	3.0	3.1	2.7	2.8	3.0	1.6	0.1
Japan	<u>7.9</u>	<u>7.3</u>	<u>7.8</u>	<u>7.4</u>	<u>5.6</u>	<u>1.2</u>	<u>0.3</u>
Total	15.0	15.4	15.5	14.3	12.9	4.5	0.8

*Organization for Economic Cooperation and Development

**According to Spring Order Books

***European Economic Community (the European "Common Market" countries)

Source: OECD data quoted by "The Economist", 7/15/78

(Note: OECD does not include U. S. data in its shipbuilding statistics)

Provided that international trade continues to expand, the surplus of ships will eventually be eroded by scrappage. However, another uncertainty is on the horizon. There is a fairly general expectation that world oil production will have peaked by the end of the century; the uncertainty concerns the exact time that the peaking will occur. A peaking of crude oil production would affect marine transportation because:

- (1) The volume of total crude oil production that moves by water is increasing now, but would decrease once total production peaked.
- (2) Some countries that now export crude oil will export less as their domestic requirements increase and, later, in anticipation of shortage, may be expected to conserve their petroleum resources for their own use.*
- (3) A general perception of constrained petroleum supply would be expected to generate pressures for reducing the amount of oil consumed in the transportation of oil.

Any one of the above items suggests that changes in inter-fuel cost parities would occur as the result of an imminent, or actual, constraint of petroleum supply. If this is so, then the order of the events becomes an important consideration. For example, widespread production limitations (item 2) in advance of producibility limitations (item 1) would be expected to delay the production peak, reduce its magnitude, and possibly cause an extended plateau of maximum production rather than a sharp peak. Moreover, a plateau would provide more time and, hence, make it easier to accomplish fuel substitution (item 3) than would a sharp peak.

Four tentative conclusions are possible:

- (1) For the near - and mid-terms, changes in marine fuel quality are likely only if system costs are thereby reduced.
- (2) International maritime competition strengthens the probability of (1).
- (3) In the long-term, substitution of other marine fuels for petroleum seems possible.
- (4) Substitutions for petroleum will probably occur in other sectors before they occur in marine transportation in the non-highway sector.

*Canada has already adopted this policy.

16.2.3 Railroad Transportation System

The direct impact of international considerations on the RR transportation system will be extremely small, since it will be confined to certain rail linkages between the U. S. and Canada. Moreover, there is a similarity of natural resources on either side of the U. S./Canadian border, which suggests that the same economic choices may apply to the overlapping RR systems of both countries.

Indirect impacts appear far more important, because the U. S. is a significant exporter of RR locomotives. It is unlikely that U. S. manufacturers would undertake separate equipment developments for domestic and foreign markets. Incremental improvements to existing power systems are more likely. A new locomotive model is not introduced until performance and reliability have been demonstrated by years of testing. And the accumulation of satisfactory performance on U. S. roads is a sales factor in locomotive exports. It is concluded that the net effect will be to raise the hurdle of economic superiority required of a new RR fuel system before it is likely to displace the continuing development pattern of the existing system.

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17. INSTITUTIONAL ISSUES AND CONSTRAINTS

M. H. Farmer

17.1 Change Processes

Change processes take time, whether the change is technological or institutional. With the former, however, it is easy to understand that many years may be needed to develop a new technology from laboratory through pilot plant scale and then, plan, construct, and start up a large manufacturing plant. It may be less easy, especially for technologists, to recognize and accept why there may be a long delay between the time that an institutional problem or constraint is identified and the time that it is resolved. Sir Geoffrey Vickers has observed⁽¹⁷⁻¹⁾:

"All Western societies for the last two hundred years. . . have exaggerated the scope for design open to their societies in the social no less than the technological field. . . I have attributed this to their lack of understanding of systemic limitations. This understanding is now dawning austere and rapidly in the technological field. It is far less in evidence and far more needed in the cultural field."

17.2 National Research Council Report

NRC's Commission on Private Sector Participation* recently prepared a report⁽¹⁷⁻²⁾ that included the examination of a number of institutional and legal difficulties in the transfer to the private sector of technology developed under Government sponsorship. Two statements from NRC's report are cited here as illustrations of the widely held view that institutional problems may be more difficult to overcome than technical problems:

"The history of government/industry collaboration on synfuels projects has been less than a happy one. Technical issues have raised some problems, but the major controversies arose over project management policies, environmental restrictions, cost-sharing formulas, pricing, and even federal land-leasing policies." (page 20)

"The successful diffusion of a new technology in the market depends on strong market-pull forces . . . These factors cannot be neatly tabulated, evaluated, and then translated into a successful market decision. In most cases, the assessment is highly subjective, and is sometimes contrary to the available objective evidence. Corporate managers routinely make judgments based on their perception of, and sensitivity to, these factors." (page 13)

*Chairman: Martin Goland, Southwest Research Institute.

17.3 Institutional Problems of Introducing a New Fuel

Institutional problems may be economic, political, administrative, jurisdictional, environmental, legal or social -- and, in many cases, a complex mixture of these elements interwoven with uncertainties about the future. One aspect of such uncertainties is that they often becloud the ordering of the priorities of change, even though these priorities may seem quite clear to those engaged in technology development. Some empirical evidence regarding uncertainty and priorities is presented in a following section on cross-impact analysis. In this section the remaining discussion is confined to institutional problems that are unique to the field of transportation. The problems concern the introduction of new fuel fuels for mobile equipment.

For the purpose of this discussion a new fuel is defined as one that cannot be used effectively in existing equipment. Therefore, the problem to be considered is that of simultaneous introduction of the new fuel and new (or radically modified) NHT equipment in which the fuel is to be used. Parenthetically, it may be added that a new fuel that could be used in existing NHT equipment need not pose serious institutional problems. In this case, the potential problems would be to demonstrate favorable economics, reliable performance, and adequate availability. However, the simultaneous need for new equipment in which to utilize a new fuel would increase the institutional difficulties to be overcome by an order of magnitude.

An essential feature of an NHT system, other than a pipeline, is that the equipment moves from place to place and must be able to obtain fuel wherever it is needed (17-3). This creates a situation in which a number of conditions must be satisfied simultaneously:

- (1) the NHT equipment industry, or some segment of it, must decide to introduce a new engine or to sponsor radical modifications of its existing engines
- (2) independently of (1), the fuels industry must decide to introduce a new fuel
- (3) preferably, for competitive reasons, several companies in both industries should decide independently to introduce the respective new products
- (4) NHT equipment users must be willing to purchase the new products (otherwise commercial introduction will be a failure)
- (5) except in special applications where fuel could be provided at a single point*, the new fuel must be widely available
- (6) the new system should offer cost or performance advantages over conventional or other alternatives, and should not present any major disadvantage.

*e.g. for mobile equipment used in mining.

Most NHT equipment is expected to have a long useful life, i.e. it is expected to be durable. Proof of durability of new equipment cannot be obtained quickly, and may require several years of testing under field conditions. Clearly, such a test program will be expensive to the equipment manufacturer -- but he has no alternative if he wishes customers to purchase (expensive) new equipment. Clearly, also, an equipment manufacturer is unlikely to develop new equipment solely for the benefit of a fuel producer who wishes to sell a new fuel. In general, the reverse of this proposition would hold also, namely that a fuel manufacturer would be unlikely to make a multimillion* dollar investment in facilities to produce a new fuel product for commercially unproven NHT equipment.

In contrast, no serious evolutionary problem is seen on the fuel side if the new NHT equipment can use conventional fuels (regardless of their raw materials source). Similarly, no serious evolutionary problems will be associated with the introduction of a new fuel if it can be used by a (large) segment of the existing NHT equipment population or if there is some (large) established demand for the new fuel regardless of the end-use application. What is important to the new fuel manufacturer is that there should be a market for his product. Also important is that the fuel should be produced in a (large) economically-sized plant, otherwise it will not be competitive** with conventional fuels. But the economy of scale possible in a large plant will not apply if the plant cannot be operated at close to its capacity. Therefore, an instant market must be found for close to the full capacity of the plant producing the new fuel. Hence, the producer of a new transportation fuel product will, in general, be at a marked disadvantage relative to the incremental producer of a conventional fuel (regardless of the raw material source of the fuel; whether conventional or unconventional).

Yet another current problem is that conventional transportation fuels are being sold at what approximates an average cost (plus profit margin) rather than at the marginal cost of new production (plus profit margin). The problem here is that an alternate fuel might compete economically with the marginal cost of (new) conventional fuel production and still be uncompetitive in the market place because the price of conventional fuels is based on historical average costs.***

The above discussion emphasizes the considerable difficulties that are anticipated with the introduction of a new fuel, but it does not imply that the task is impossible. In fact, advance recognition of the difficulties should make the task somewhat easier. Nevertheless, the magnitude of the transitional problems with new fuels (that are incompatible with existing equipment) are such that evolutionary changes to fuel composition (that do not create incompatibility) seem more likely.

*in the case of synthetic fuels plants, the capital investment required may exceed \$1 billion for a single plant.

**without subsidies or the like.

***i.e. the higher cost marginal production of conventional fuels is "rolled into" the average cost of all production of conventional fuels. Alternate fuels that are fully compatible with conventional fuels have the potential advantage of being rolled into the transportation fuel supply system before being sold to consumers. Novel or incompatible fuels would not have this advantage.

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18. EXPERIMENT IN PROBABILISTIC FORECASTING

M. H. Farmer

The projections made in this study depend on assumptions that are discussed elsewhere in the report. In general, as in the Energy Information Administration's projections reviewed earlier, the projections may be considered "baseline". Quoting from the Foreword to EIA's report: "Generally, forecasts must be uncertain. This fact implies that to be fully useful a forecast should carry with it a trustworthy indication of just how much uncertainty does attach to it." Providing such an indication is a difficult task. It has been attempted, however, using some of the concepts that underlie a forecasting technique called "cross-impact analysis." Some notes on cross-impact analysis are given in Appendix 18-1.

The first questionnaire concerned types of "event" that are likely to affect alternative fuels for NHT systems:

- (1) The time-frame in which world crude oil production is expected to peak.
- (2) The expected "pattern" of change in the price of crude oil during the period 1980 to 2000.
- (3) The expected priorities for curtailment of petroleum consumption at the time a peaking of production occurs.

Each of the above "events" is extrinsic or exogenous to NHT systems per se. The main purposes of the subjective forecasts are to:

- Suggest the range of uncertainty that exists today with respect to some of the factors likely to affect the future development of alternate fuels and NHT systems. (Put differently, if it were possible to define each of these factors with certainty then, instead of a "baseline case," it would be possible to define a highly probable case.)
- Show how the change of a single key assumption (simulated in the second questionnaire as assumed events) can lead to significant changes in the perceived probabilities of other events.

The two questionnaires used to generate estimates of subjective and conditional probabilities are reproduced in Appendix 18-2. The questionnaires were pretested by a small group of Exxon Research(ER) employees, and were then modified to remove ambiguities in wording. The revised questionnaires were then submitted to another group of ER employees and responses were also obtained from a group assembled by the DOE project monitor.

The detailed results of the questionnaires are reported in Appendix 18-3, while key findings are discussed below.

18.1 Pattern of Responses

Experimental evidence was obtained that there is considerable uncertainty about "energy futures" when measured by individual perceptions. Specific inferences, or tentative conclusions, are:

- (1) Patterns of response by the ER and DOE groups were very similar.
- (2) There were considerable differences in response within each group. These differences are attributable to different assumptions made by individuals.
- (3) Polarized projections were made for value-laden issues such as curtailment priority of fuel use for personal automobiles. The same polarization was observed in both ER and DOE groups.
- (4) Some individuals in each group had difficulty with probabilistic forecasting.
- (5) In spite of the pretest, some ambiguities in wording of questions and instructions remained in the questionnaires. Even the slightest ambiguity leads to misunderstandings.
- (6) The ER group's responses appeared to weight correlation or association as much or more than causation (in the estimation of conditional probabilities). The DOE group appeared to be concerned primarily with causation. This was the only matter for which a material difference was observed between the two groups.

18.2 Discussion and Interpretation of Experimental Results

The first questionnaire contained three sets of questions ("A", "B", and "C"). The "A" and "B" sets required subjective estimates of probability with respect to the time-frame in which world crude oil production is expected to peak and the pattern of change in the world price of crude oil during the period 1980 to 2000. The "C" set of questions required a rank ordering of curtailment priorities for six different uses of petroleum in the event of a limitation of crude oil supply. The "C" questions were posed in terms of the respondents' expectations of what would (not should) occur. The second questionnaire used the "A" and "C" questions in the form of a cross-impact matrix. Each of the questions, in turn, was assumed to be an "event". The respondents were asked to estimate the impact of each of these "events" on the other activities in the matrix, and were asked to do this by estimating whether a particular event ($P=1$) would significantly change the estimate given in response to the first questionnaire. Put differently, the task was to judge whether the conditional probabilities were significantly different from the pertinent subjective probabilities estimated previously.

The purpose of these questionnaires was not to generate alternative projections of energy futures. The purposes were to illustrate:

- (1) the range of uncertainty that exists (among energy technologists) about energy futures.
- (2) that plausible* changes of assumption regarding a given possibility can affect the probabilities estimated for other events.
- (3) that inferences may be derived from such indications of uncertainty.

Combination of all responses** to the first questionnaire gives the following results for the "A" set of questions:

	<u>Peaking of World Crude Oil Production</u>	<u>% Probability Estimated by All Respondents</u>
A-1	before 1985	7
A-2	between 1985 and 1990	25
A-3	between 1990 and 2000	42
A-4	after year 2000	26

The estimates imply a "greatest probability" around 1995, which is close to several published expectations. However, the probability distribution is very flat, and approximates a 4% probability of a peak in any year after 1985. This view reflects considerable uncertainty and is not typical of published expectations.

Similarly, combination of all responses to the "B" set of questions gives the following picture:

	<u>Pattern of World Oil Prices During Period 1980-2000</u>	<u>% Probability Estimated by All Respondents</u>
B-1	no price increase in constant dollars	8
B-2	smooth exponential increased in real terms	19
B-3	one or more discontinuous, but sharp, increases in real terms	32
B-4	relatively small but steady increases to 1990, followed by sharper increases to 2000	41

*At the time of writing this report, the Administration has just published its proposed contingency plans for allocating crude oil in the event of continued curtailment of oil exports from Iran. Related plans for gasoline rationing are being developed (New York Times, 1/12/79).

**21 responses from ER personnel and 10 responses from the DOE/outside group.

Most published forecasts make assumptions equivalent to B-1 or B-2, or use these assumptions to represent two different cases. Respondents to the questionnaire assigned relatively low probabilities to B-1 and B-2 and higher probabilities for more turbulent price behavior -- again interpretable as a higher level of both qualitative and quantitative uncertainty than is portrayed in most published forecasts. The latter tend to focus on quantification in terms of energy resources rather than on the possible behavior of the energy system. In fact, the perceptions of the respondents to the questionnaires may be compatible with the quantitative projections. However, their format and focus is different thereby making it possible to derive different implications. A common orientation of the quantitative projections is toward supply planning, whereas the indications of uncertainty may be conceived as inputs to contingency or strategic planning especially in relation of R&D.

The "C" set of questions is not to be found in published form (where supply and demand are hypothetically balanced). The combined responses may be grouped into three categories of "curtailment priority in the event of an actual shortage of petroleum". The rating scale used by individuals ran from 1 (highest priority) to 6 (lowest priority):

<u>Fuel Use Curtailed</u>		<u>Group Rating</u>
C-2	personal auto	2.4
C-1	air travel	2.9
C-4	industrial fuel oil	3.0
C-5	chem. feedstock	3.8
C-6	marine fuel	3.9
C-3	home heating oil	4.9

For the two non-highway transportation modes represented, air travel was judged more likely to be curtailed than marine fuel use. The rating of 2.9 for air travel is not significantly different from the 3.0 rating for industrial fuel oil. It may be noted that an approach to curtailment of the use of industrial fuel oil is present in the Powerplant and Industrial Fuel Use Act of 1978*.

The dispersion of the curtailment priority ratings by the individual respondents is illustrated in Figure 18-1. The pooled ratings, from 2.4 for C-2 (personal auto) to 4.9 for home heating oil (C-3) are repeated on the center, horizontal scale. For each petroleum use, there is a dashed, vertical line that connects numbers in parenthesis. Each of these numbers** denotes the number of respondents who assigned the pertinent curtailment priority (in left hand vertical scale) to the particular fuel use. For example, it may be seen that 18 (or 58%) of the respondents assigned the lowest curtailment priority to home heating oil, while 17 (or 55%) of the respondents assigned the highest curtailment priority to personal auto use. Similarity of response is evident for air travel

*One of the five bills comprising the National Energy Act of 1978.

**Multiplying any of these numbers by 3.2 converts them to a percentage response.

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and industrial fuel oil, and also for chemical feedstock and marine fuel. It is apparent that the respondents made different assumptions when they were estimating priorities. It would be very interesting to know what these assumptions were, but such investigation was beyond the scope of the present study.

The second questionnaire had the format of a cross-impact matrix, and respondents were asked to judge whether the conditional probabilities resulting from assumed events were significantly different from the pertinent subjective probabilities estimated previously. About 45% of the responses fell into this category. For 13 out of 60 positions in the matrix, the conditional responses of the DOE group differed from those of the ER group. Available evidence does not permit more than an (unconfirmed) hypothesis that the ER group's responses may have attached as much, or more, importance to association as to causation, while the DOE group appeared to be concerned primarily with causation. For example, on the average:

- the ER group may have felt that something as serious (in an economic or social sense) as the curtailment of air travel would not occur unless world oil production had peaked or was expected to do so imminently.
- the DOE group may have felt that curtailment of air travel would avert or postpone the peaking of world oil production.

It is believed that the assumptions made by individuals concerning energy futures and priorities are important to the resolution of institutional problems. Different assumptions lead to differing perceptions of priority. It may be difficult to resolve conflicts in priority without first identifying and trying to resolve the differing assumptions that underlie the conflicts.

The limited scope of the experiment did not permit identification of the assumptions used by the participants. Any future work should include the identification and, if possible, the interactive discussion of key subjective assumptions.

If credence is given to the degree of uncertainty manifest in the responses to the two questionnaires, then some tentative inferences may be drawn for technology development. For example, there may be considerable risk in acting upon a direct and precise answer to the question: "when will Technology 'X' be economically competitive with current technology?" since, by analogy with the "A" set of estimated probabilities, "when" may occur at any time during the next several decades -- due to the impact of exogenous events, rather than because of quantitatively predictable changes in the relative costs of Technology "X" and the existing technology that "X" is intended to replace. A principal alternative to looking for certainty where it may not exist, is to develop contingency plans that will "fail safe" under a variety of different assumptions. In this approach, the assumptions, which model different uncertainties, are combined into different scenarios. It is then possible to assess a given technology not only in relation to an individual scenario but also with respect to a group of scenarios that encompass a wide range of future possibilities.

APPENDIX 18-1

NOTES ON CROSS-IMPACT ANALYSIS

The concept of cross-impact analysis as a forecasting technique and the use of a cross-impact matrix were formalized just over a decade ago. The inventors, Theodore J. Gordon and Olaf Helmer, devised the technique to overcome an objection to their earlier "Delphi" method of using panels of experts to make projections about future events. The Delphi technique required the panelists to concentrate on one event at a time. Hence, the panelists were not able to take into account possible interactions among the events they were forecasting. Cross-impact analysis permitted the subjective probability estimates (of Delphi) to be modified, subsequently, by estimates of conditional probability. However, the use of a cross-impact matrix is not limited to being an "add on" to Delphi forecasting. In fact, it can be applied to consideration of the interactions among future "events", without regard to the source of the forecast. Martino observes that cross-impact analysis "is likely to be even more valuable when the forecasts have been obtained from several sources, since it is less likely that interactions (among the forecasts) were taken into account by the different sources", i.e. that a partial, but unstructured, cross-impact analysis has already occurred.

Because of its application to decision-making under uncertainty and because there is a rather general perception that uncertainty about the future is increasing, the techniques of cross-impact analysis are under rapid development and now include adjuncts such as trend impact analysis (TIA) and probabilistic system dynamics, (PSD).

It is generally, but not universally, accepted that the utility of forecasts is more important than their precision, especially when the purpose of the forecast is to guide current decisions. A realistic goal is to seek comparative advantage rather than perfection.

A review of futures research and forecasting techniques is outside the scope of this study. However, a few pertinent citations are made below; their source will be apparent from the abbreviated bibliography that follows.

Citation #1

"A cross-impacting forecasting approach takes into account the mutual impacts of different events or trends. . . There are four kinds of cross-impacts that should be distinguished:

- (1) Time series or trends may interact . . .
- (2) The probabilities of different unique events may interact.
For example, development of cheap fusion power may preclude the development of cheap geothermal power.

(3) Events may impact trends.

(4) Trends may affect the probabilities of events."

Citation #2

"Temporal order effects may also be significant; which of two events occurs first may be all-important in determining the impact on a third event or on some trend."

Citation #3

"Forecasting is rarely an end in itself. Rather it is usually a means to an end, and that end is typically a correct decision, whose achievement is to be facilitated by the forecast. Note: The decision is normally in the present, at the time that the users or consumers of the forecast receive or consider the forecast."

Citation #4

"Let us start with a few observations and assumptions about the nature of futures research:

- (1) It is utility-oriented. . .
- (2) It is intrinsically global in approach. . .
- (3) Bias is inevitable. . .
- (4) Bias is desirable. . .
- (5) Dissemination of futures research affects the future. . .
- (6) Resistance plays a role in acceptance of results. . ."

Citation #5

"The various futures must not all be minor variations of a single theme, nor should the deck be stacked by the inclusion of only one 'preferred' future and several totally unacceptable alternatives."

Citation #6

"Reliance on the intuitive judgment of experts thus is not just a temporary expedient but a necessary ingredient of futures research, because they are needed in all phases of the effort. They are called upon (1) to supply judgmental data about the future, based on their intuitive, though often theoretically unstructured, insights into real-world phenomena; (2). . ."

Citation #7

"A sizeable number of the respondents believe that the only sensible way of trying to improve forecasting is by trying to forecast."

Abbreviated Bibliography

- (1) T. J. Gordon and H. Hayward, "Initial Experiments with the Cross-Impact Matrix Method of Forecasting," *Futures*, December 1968, pp 100-116.
- (2) T. J. Gordon, "Cross-Impact Matrices," *Futures*, December 1969, pp 427-431.
- (3) Murray Turoff, "An Alternative Approach to Cross-Impact Analysis," *Technological Forecasting and Social Change*, 1972, No. 3, pp 309-339.
- (4) Joseph P. Martino, "Technological Forecasting for Decision Making," Edsevier, New York, 1975, p 272.
- (5) Wayne I. Boucher, editor, "The Study of the Future: An Agenda for Research," prepared with the support of the National Science Foundation; copyright by The Futures Institute, Inc., 1977.*

The following references are a part of (5) above; titles of the papers from which citations were taken are listed below:

- Citation #1: Herbert Gerjuoy, "A New Perspective on Forecasting Methodology," Chapter 2, page 21.
- Citation #2: *ibid*, page 22.
- Citation #3: *ibid*, page 31.
- Citation #4: Willis W. Harman, "On Normative Forecasting," pp 76-77.
- Citation #5: Joseph P. Martino, "Forecasting and its Impact on Policy-Making," page 119.
- Citation #6: Olaf Helmer, "An Agenda for Futures Research," page 245.
- Citation #7: Wayne I. Boucher and John V. Helb, "Results from the Survey of Current Forecasting Efforts," page 280.

APPENDIX 18-2

QUESTIONNAIRES USED IN FORECASTING EXPERIMENT

ALTERNATIVE ENERGY SOURCES FOR NON-HIGHWAY TRANSPORTATION

- We are seeking your help with an alternate fuels study we are making for DOE.
- We need answers to 2 short questionnaires. Pre-testing suggests that about 30 minutes of your time will be needed. Each questionnaire has a "code number"; your individual responses will be kept confidential.
- Base case projections have already been made. The purpose of the questionnaires is to explore some alternative assumptions. Your responses will help us to scope these alternatives.
- The first questionnaire has a Delphi format (but there will be no iterations of the questionnaire as in a standard Delphi forecast). Your individual (subjective) estimates are wanted. Please complete the first questionnaire before tackling the second.
- The second questionnaire has the format of the "first round" of a cross-impact analysis. (There will be no iterations.)

Questionnaire No. 1Question "A"

This question concerns the future production of crude oil. Some of the possibilities that have been suggested are:

- A-1: World crude oil production will peak before 1985.
- A-2: World crude oil production will peak between 1985 and 1990.
- A-3: World crude oil production will peak between 1990 and 2000.
- A-4: World crude oil production will peak after 2000.

- Please estimate these possibilities as percentage probabilities (which should add to 100).
- Please place an * next to your probability estimate if you believe that peaking will occur as the consequence of producer actions rather than physical (resource) limitations.

Your Estimates	
A-1 =	
A-2 =	
A-3 =	
A-4 =	_____
	100

Question "B"

This question concerns the pattern of future world oil prices during the period 1980 to 2000.

Possibilities that have been suggested are:

- B-1: No price increase relative to general inflation, i.e. no increase in "constant dollars per barrel".
- B-2: A price increase pattern that approximates $x\%$ per year, i.e. a "smooth" exponential increase in real terms.
- B-3: One or more discontinuous but sharp price increases in real terms.
- B-4: Relatively small but steady price increases during the period 1980 to 1990, followed by sharper increases during the period 1990 to 2000.

• Please estimate these possibilities as percentage probabilities.

Your Estimates
B-1 =
B-2 =
B-3 =
B-4 =

• If none of the above possibilities comes close to your expectation, please describe this expectation as briefly as you can:

--

Question "C"

This question makes the assumption that the U.S. will experience a shortage of petroleum at some time in the future, and that the shortage will be more than transitory, e.g. at the time it occurs there will be a general perception that the shortage will last for at least a year.

Under conditions of actual shortage, some uses of petroleum would have to be curtailed (not eliminated, but reduced in extent).

- Regardless of the mechanisms by which curtailment might be achieved, please rank order* what you judge the curtailment priorities would be for the following uses of petroleum liquids:

- C-1: Air travel
- C-2: Personal automobile use
- C-3: Domestic heating oil use
- C-4: Industrial fuel oil use
- C-5: Chemical feedstock use (of petroleum liquids)
- C-6: Marine bunker and marine diesel fuel use

Your Estimates
C-1 =
C-2 =
C-3 =
C-4 =
C-5 =
C-6 =

*1 = highest priority or most likely to be curtailed.

6 = lowest priority or least likely to be curtailed.

Questionnaire No. 2
Cross-Impact Analysis

- This questionnaire has the format of a "cross-impact" matrix.
 - The task is to estimate the impact of assumed events on other items in the matrix. For this purpose, each of the items in the top horizontal row (A-1 to A-4, and C-1 to C-6) is to be considered separately as a future event. Then, the subsequent impact of this assumed event on each of the items in the vertical column under the event is to be estimated.
 - Because an event could not change what had already taken place, some "boxes" in the matrix are not meaningful and have been blacked out.
 - You may find it easier to complete the matrix if you have your answers to the "A" and "C" questions of Questionnaire No. 1 in front of you. The vertical column at the left of the matrix provides space for your answers.
 - The required estimate is of how you judge the assumed event would change the probabilities that you have already estimated in Questionnaire No. 1.
- ☐ + If you judge that the occurrence of the assumed event would increase a previously estimated probability, put a + in the pertinent box of the matrix. (Please do this even if you do not believe the event is likely.)
- ☐ - If you judge an event would decrease a previously estimated probability, put a - in the pertinent box.
- ☐ 0 If you feel that a given event would have little or no impact on your previously estimated probability, put a 0 in the box.
- ☐ N If the question is unclear or, for any reason, you do not wish to answer it, put an N in the box.

QUESTIONNAIRE No.2

CROSS-IMPACT MATRIX

CODE No.

ENTRY OF YOUR RESPONSES TO QUESTIONNAIRE No.1
MAY HELP YOU TO COMPLETE THE MATRIX

YOUR Q #1 RESPONSES	DESCRIPTION OF "EVENT"	SEE COLUMN AT LEFT FOR DESCRIPTION OF "EVENTS"									
		A-1	A-2	A-3	A-4	C-1	C-2	C-3	C-4	C-5	C-6
	A-1 WORLD CRUDE OIL PRODUCTION PEAKS BEFORE 1985										
	A-2 WORLD CRUDE OIL PRODUCTION PEAKS BETWEEN 1985 AND 1990										
	A-3 WORLD CRUDE OIL PRODUCTION PEAKS BETWEEN 1990 AND 2000										
	A-4 WORLD CRUDE OIL PRODUCTION PEAKS AFTER YEAR 2000										
	C-1 CURTAIL AIR TRAVEL										
	C-2 CURTAIL PERSONAL AUTOMOBILE USE										
	C-3 CURTAIL DOMESTIC HEATING OIL USE										
	C-4 CURTAIL INDUSTRIAL FUEL OIL USE										
	C-5 CURTAIL CHEMICAL FEEDSTOCK USE OF PETROLEUM LIQUIDS										
	C-6 CURTAIL MARINE BUNKER AND DIESEL FUEL USE										

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APPENDIX 18-3

RESULTS OF DELPHI-TYPE AND CROSS-IMPACT TYPE QUESTIONNAIRES

1. Introduction

A pre-test of the questionnaires in Appendix 18-2 was given to eight professional staff at Linden*. These individuals have considerable experience with the development of energy technology but not, in general, with probabilistic forecasting techniques. The principal purpose of the pre-test was to find out what needed to be changed in the questionnaires in order to reduce ambiguity and to make them more useful as tools of inquiry. As a result of the pre-test:

- minor changes of wording were made to Questionnaire No. 1 to reduce ambiguity.
- drastic simplification of Questionnaire No. 2 was made to reduce its complexity and ambiguity.

2. Results of Pre-Tests of Questionnaires

Even with its imperfections, the pre-test of Questionnaire No. 1 indicated a wide divergence of views about "energy futures" among a group of individuals who, by many conventional measures, might be regarded as similar. The divergence was most evident when the response involved personal attitudes or values, e.g. toward curtailment priorities in the event of a petroleum shortage. The results are reported in Table 18-1, and are summarized below:

- relatively low probabilities were estimated for a peaking of world oil production before 1985 (7%) or after the year 2000 (14%). The majority felt that a producer peak (as distinct from a physical producibility limit) would occur between 1985 and 2000.
- relatively low probabilities were estimated for constant dollar world oil prices (11%) or smooth "x% per year" increases (22%) during the period 1980 to 2000. Opinion was divided between sharp, discontinuous increases (31%) and small increases prior to 1990 followed by sharper increases thereafter (36%).
- curtailment priorities fell into three groups:
 - (1) highest priority: air travel (2.5), personal automobile use (2.7), and industrial fuel oil (2.8); no statistically significant difference among these ratings.
 - (2) medium priority: chemical feedstock (3.9) and marine fuel (4.0).
 - (3) lowest priority: home heating oil (5.0).

*seven of these individuals were employees of the Government Research Laboratories of Exxon Research and Engineering Company; the eighth while not a GRL professional, was engaged in government contract work.

TABLE 18-1

PRE-TEST RESPONSES TO QUESTIONNAIRE NO. 1

Respondent No.	Production Peak					Price Behavior					Curtailment Priorities					
	A-1	A-2	A-3	A-4		B-1	B-2	B-3	B-4		C-1	C-2	C-3	C-4	C-5	C-6
101	25*	50*	15	10		10	25	40	25		3	5	6	2	4	1
102	0	20*	80*	0		10	10	40	40		4	1	2	5	3	6
103	0	10	50	40		10	20	20	50		4	1	2	3	5	6
104	5*	35*	40	20		5	20	45	30		2	1	6	4	5	3
105	5	50*	40*	5		15	25	20	40		3	1	6	2	5	4
106	10*	30*	40	20		10	30	30	30		1	5	6	4	2	3
108	0	30*	60*	10		10	30	25	35		2	5	6	1	3	4
109	10*	50*	30*	10		20	20	25	35		1	3	6	2	4	5

Range	0	10	15	0		5	10	20	25		1	1	2	1	2	1
	25	50	80	40		15	30	45	50		4	5	6	5	5	6
Mean	7	34	45	14		11	22	31	36		2.5	2.7	5.0	2.8	3.9	4.0

The pre-test responses to Questionnaire No. 2* are not recorded because, in its original form, it did not yield valid results.

3. Results of Questionnaire No. 1

A group of thirteen professionals** participated in the (revised) tests. The professional experience of these individuals was very similar to that of the pre-test group. Responses are reported in Table 18-2, and are summarized below:

- relatively low probabilities were estimated for a peaking of world oil production before 1985 (7%) or in the period 1985 to 1990 (18%). The estimated 75% probability of a post-1990 peak was divided into (a) between 1990 and 2000 (41%) and (b) after 2000 (34%).
- unlike the pre-test group, few individuals expected a producer peak instead of a producibility limitation.
- the response pattern to the price behavior questions was virtually identical to that of the pre-test group.
- curtailment priorities could be arranged into three groups, but it is not clear whether air travel should be in the highest priority or the medium priority group:
 - (1) highest priority: personal automobile use (2.4), industrial fuel oil (2.8) and, possibly, air travel (3.2).
 - (2) medium priority: marine fuel (3.6) and chemical feedstock (4.0).
 - (3) lowest priority: home heating oil (5.0).

A comparison of the pre-test and test responses is given in Table 18-3.

For the "A" (production peak) and "B" (price behavior) questions both the dispersion of the individual responses and the group means are not surprising. Moreover, the fact that some questions were slightly reworded precludes a precise comparison of the pre-test and subsequent test responses. Nevertheless, the degree of certainly expressed in some answers is worth noting:

- in the pre-test, three individuals estimated zero probability of a peak in world crude oil production (even by a producer limitation) before 1985. One of these individuals also estimated a zero probability of a peak after the year 2000.

*which differed in form and content from the simplified version in Appendix 18-2.

**different individuals, but also drawn primarily from ERE's Government Research Laboratories.

TABLE 18-2

TEST RESPONSES TO QUESTIONNAIRE NO. 1

Respondent No.	Production Peak					Price Behavior					Curtailment Priorities					
	A-1	A-2	A-3	A-4		B-1	B-2	B-3	B-4		C-1	C-2	C-3	C-4	C-5	C-6
200	10	30	40	20		20	40	20	20		4	6	5	1	3	2
201	10	20	50	20		5	30	15	50		5	1	2	3	6	4
202	10	30	50	10		20	10	50	20		2	1	6	4	3	5
203	25	50	20	5		5	35	10	50		4	2	6	1	3	5
204	5	10	50*	35*		5	15	45	25 ^ø		2	1	6	4	5	3
205	0	10	40	50		0	40	30	30		2	1	3	4	5	6
206	5	10	80	5		0	10	10	80		2	1	6	4	5	3
207	0	10	40	50		5	20	45	30		5	6	4	2	3	1
208	10	20	30	40		10	40	20	30		1	3	6	5	4	2
209	0	25	50	25		0	0	25	75		3	1	6	2	5	4
210	10	20	50	20		10	10	40	40		4	6	5	2	3	1
211	0	5	10	85*		5	5	85	5		5	1	4	2	3	6
212	0	0	20*	80		0	20	30	50		2	1	6	3	4	5

Range	0	0	10	5		0	0	10	5		1	1	2	1	3	1
	25	50	80	85		20	40	85	80		5	6	6	5	6	6
Mean	7	18	41	34		7	21	33	39		3.2	2.4	5.0	2.8	4.0	3.6

øThis set of responses adds to 90%.

TABLE 18-3

COMPARISON OF GROUP MEAN RESPONSES TO QUESTIONNAIRE NO. 1

World crude oil production will -		<u>Pre-Test</u>	<u>Test</u>
A-1	- peak before 1985	7	7
A-2	- peak between 1985 and 1990	34	18
A-3	- peak between 1990 and 2000	45	41
A-4	- peak after 2000	14	34
Pattern of world oil prices during period 1980 - 2000:			
B-1	no increase in constant dollars per barrel	11	7
B-2	smooth exponential, annual increase	22	21
B-3	one or more discontinuous but sharp price increases	31	33
B-4	relatively small and steady to 1990; sharper increases 1990 - 2000	36	39
	Expectations other than B-1, B-2, B-3 or B-4	nil	nil
Curtailement priorities* (1 = most likely to be curtailed)			
C-1	air travel	2.5	3.2
C-2	personal automobile use	2.7	2.4
C-3	domestic heating oil use	5.0	5.0
C-4	industrial fuel oil use	2.8	2.8
C-5	chemical feedstock use (of petroleum liquids)	3.9	4.0
C-6	marine bunker and marine diesel fuel use	4.0	3.6

*in the event of an oil shortage and a general perception that the shortage will last for at least a year.

- in the subsequent test, five individuals (almost 40% of the group) estimated a zero probability of a peak before 1985. One of these individuals also estimated a zero probability of a peak before 1990. Three of these same individuals and one other saw no possibility of world crude oil prices remaining stable in constant dollars during the period 1980 to 2000.

Nevertheless, most individuals in both groups made estimates that indicated considerable uncertainty about the future.

Analytically, the most interesting responses were given to the "C" questions (curtailment priorities), which require value judgments to be made. The pre-test group gave a polarized response to the curtailment priority for personal automobile use:

- 4 respondents estimated a "1" (highest priority)
- 1 respondent estimated a "3"
- 3 respondents estimated a "5" (next to lowest priority)

The polarization was even more marked in the responses of the subsequent test group:

- 8 respondents estimated a "1" (highest priority)
- 1 respondent estimated a "2"
- 1 respondent estimated a "3"
- 3 respondents estimated a "6" (lowest priority)

It is apparent that the respondents made different assumptions when they were estimating priorities. It would be very interesting to know what these assumptions were. Such investigation was beyond the scope of the present study.

4. Additional Testing of Questionnaire No. 1

It was recognized that additional insight might be provided if responses were obtained from non-Exxon Research employees. Accordingly, the DOE Project Officer arranged for the questionnaires to be submitted to several DOE employees and to an outside group. The ten responses so obtained are recorded in Table 18-4, which also repeats the mean responses of the ER test group. The responses of the DOE/outside group may be summarized:

- low probabilities were estimated for a peaking of world crude oil production before 1985 (8%) or in the period 1985 to 1990 (25%). The estimated 67% probability of a post-1990 peak was divided into (a) between 1990 and 2000 (41%) and (b) after 2000 (26%). This pattern of response was similar to that of the ER test group.
- one individual felt that the peak in production would be induced by high prices, i.e. by a peaking of demand.
- the price behavior responses were very similar to those of the ER test group.

TABLE 18-4

DOE AND OUTSIDE GROUP RESPONSES TO QUESTIONNAIRE NO. 1

Respondent No.	Production Peak					Price Behavior					Curtailment Priorities					
	A-1	A-2	A-3	A-4		B-1	B-2	B-3	B-4		C-1	C-2	C-3	C-4	C-5	C-6
2102	0	10	50	40		0	0	60	40		2	1	6	4	5	3
2104	0	25	45	30		0	30	0	70		4	1	5	2	3	6
2105	10	20	50	20		10	25	40	25		1	2	6	3	5	4
2106	5	5	10	80		2	3	20	75		4	5	6	2	1	3
X210	5*	35*	30*	30		5	10	37 ^ø	48 ^ø		4	3	5	1	2	6
X211	10	25	60	5		10	10	70	10		5	1	2	3	4	6
X212	12	30	45	13		10	15	40	35		2	1	6	3	4	5
X220	10	50	40	0		20	0	10	70		1	5	6	4	2	3
X221	5	20	45	30		20	20	20	40		1	2	3	6	5	4
X222	20	30	40*	10		0	30	20	50		6	1	2	5	4	3

Range	0 20	5 50	10 60	0 80		0 20	0 30	0 70	10 70		1 6	1 5	2 6	1 6	1 5	3 6
Mean	8	25	41	26		8	14	32	46		3.0	2.2	4.7	3.3	3.5	4.3

ER Test Group

Mean^{øø}

7 18 41 34 7 21 33 39 3.2 2.4 5.0 2.8 4.0 3.6

^øThis respondent assigned a 20% probability to B-3, 30% to B-4, and 35% to a combination of B-3 and B-4. For the purpose of Table 4, the 35% probability of the combination was divided between B-3 and B-4.

^{øø}from final column of Table 3.

- curtailment priorities could again be arranged into three groups:
 - (1) highest priority: personal automobile (2.2), and air travel (3.0).
 - (2) medium priority: industrial fuel oil (3.3), chemical feedstock (3.5) and marine fuel (4.3).
 - (3) lowest priority: home heating oil (4.7).
- the polarization of the responses to certain questions was similar to that of the ER groups.

When the curtailment priorities of all respondents (both ER groups and the DOE/outside group) are aggregated, there is a further validation of the observation of clustering into three categories:

- (1) highest curtailment priority: personal automobile (2.4), air travel (2.9), and industrial fuel oil (3.0).
- (2) medium priority: chemical feedstock (3.8) and marine fuel (3.9).
- (3) lowest priority: home heating oil (4.9).

Perhaps the most interesting set of responses were those given to question C-2 (curtailment priority for personal automobile use). In each of the three responding groups, at least half assigned the highest curtailment priority to personal automobile use while one quarter of each group assigned the lowest curtailment priority to this fuel use. When all responses are aggregated, the polarized result is:

	<u>%</u>
highest or next highest curtailment priority	64
medium priority	10
lowest or next lowest curtailment priority	26

5. Results of Questionnaire No. 2

Eleven of the thirteen ER respondents to the first questionnaire also responded to the cross-impact questions in the second questionnaire. One of the non-respondents objected to the concept of conditional probability. The other non-respondent felt that the questions were unanswerable without prior specification of the time of occurrence of a particular event (e.g. curtailment of industrial fuel oil use). All ten DOE/other group participants responded to the second questionnaire, but one of the responses was fragmentary. Another respondent was concerned about prior specification of time of occurrence.

The task involved the estimation of conditional probabilities (i.e. the probability of event E_1 occurring, given the occurrence of event E_2). Separately, each E_2 event was assumed to occur ($P = 1$), and the task was to estimate whether its occurrence would increase (+), not significantly affect (o), or decrease (-) the pertinent probabilities previously estimated in the first questionnaire.

The responses of the ER group are summarized in Tables 18-5 and 18-7. while the DOE/outside group's responses are given in Tables 18-6 and 18-8. Several general points will be made before discussing and comparing the responses of the two test groups:

- while there are no uniquely correct responses (to either of the questionnaires), certain responses are logically incorrect. For example, it is not possible for each of the four "A" activity probabilities to increase (or decrease) relative to the estimates given in response to Questionnaire No. 1 (since the sum of these four probabilities must be 100%). Some respondents in both test groups did not recognize this constraint.
- the second questionnaire permitted the response "N" ("if the question is unclear or, for any reason, you do not wish to answer it"). In fact, only one respondent in each group made any use of "N". In one case, the response was restricted to the impact of the "C" events on activity A-1. In the other case, "N" was applied to the impact of the "C" events on each of the four A activities. Superficially, the virtual absence of "N" responses indicates that all of the questions/tasks were clear. Unfortunately, however, there is other evidence (e.g. personal comments, illogical responses) that suggests otherwise. Moreover, in spite of the anonymity of the questionnaires, it is possible that some participants did not wish to reveal a lack of understanding -- even though the fault may have been in the design and wording of the questions.
- in the first questionnaire, responses to the "C" questions required a ranking of curtailment priorities from 1 to 6. The second questionnaire did not provide for re-ranking of "C" priorities, but only for changes in impact relative to the responses given previously.* Hence, a "+" response, for example, has been interpreted as meaning that a given fuel use curtailment would be more likely than previously estimated.
- there were many "o" responses: 54% of the ER group's and 57% of the DOE/outside group's responses fell in this category. Considering the nature of the "events", it might be reasoned that a change from an estimated fractional probability (in Questionnaire No. 1) to a forced assumption of certainty (in Questionnaire No. 2) would produce estimates of significant changes of impact in most cases. The fact that significantly changed impacts were estimated in only about 45% of the cases has at least four possible explanations:

*This is recognized, now, as a flaw in the design of the second questionnaire.

18-3-10

TABLE 18-5

ER GROUP'S CONDITIONAL RESPONSES TO "A" EVENTS

Fuel Use Impacted by Event	Event											
	A-1 Peaks before 1985			A-2 Peaks between 1985 and 1990			A-3 Peaks between 1990 and 2000			A-4 Peaks after Year 2000		
	+	0	-	+	0	-	+	0	-	+	0	-
C-1 (air travel)	6	4	1	6	4	1	4	7	0	3	5	3
C-2 (personal auto use)	6	4	1	6	3	2	4	6	1	2	6	3
C-3 (heating oil use)	3	8	0	3	8	0	2	8	1	1	7	3
C-4 (ind. fuel oil use)	7	4	0	6	4	1	4	6	1	3	7	1
C-5 (chem. feed use)	6	5	0	5	6	0	4	6	1	2	7	2
C-6 (marine fuel use)	7	3	1	4	7	0	3	8	0	2	7	2

	Excess of + over - Responses			
	A-1	A-2	A-3	A-4
C-1	5	5	4	0
C-2	5	4	3	-1
C-3	3	3	1	-2
C-4	7	5	3	2
C-5	6	5	3	0
C-6	6	4	3	0

TABLE 18-6

DOE/OUTSIDE GROUP'S CONDITIONAL RESPONSES TO "A" EVENTS

Fuel Use Impacted by Event	Event											
	A-1 Peaks before 1985			A-2 Peaks between 1985 and 1990			A-3 Peaks between 1990 and 2000			A-4 Peaks after Year 2000		
	+	0	-	+	0	-	+	0	-	+	0	-
C-1 (air travel)	6	2	1	4	4	1	4	4	1	3	3	3
C-2 (personal auto use)	5	3	1	3	5	1	4	4	1	2	3	4
C-3 (heating oil use)	3	5	1	1	8	0	2	6	1	1	4	4
C-4 (ind. fuel oil use)	6	3	0	5	3	1	4	4	1	2	4	3
C-5 (chem. feed use)	5	4	0	5	4	0	4	4	1	2	4	3
C-6 (marine fuel use)	6	3	0	3	5	1	3	4	2	2	3	4

	Excess of + over - Responses			
	A-1	A-2	A-3	A-4
C-1	5	3	3	0
C-2	4	2	3	-2
C-3	2	1	1	-3
C-4	6	4	3	-2
C-5	5	5	3	-1
C-6	6	2	1	-2

Note: one DOE/outside group participant did not respond to the "A" items.

TABLE 18-7

ER GROUP'S CONDITIONAL RESPONSES TO "C" EVENTS

Activity Impacted by Event	Fuel Use Curtailment Event																	
	C-1 (air travel)			C-2 (personal auto)			C-3 (heating oil)			C-4 (ind. fuel oil)			C-5 (chem. feed)			C-6 (marine fuel)		
	+	0	-	+	0	-	+	0	-	+	0	-	+	0	-	+	0	-
A-1 (peak by 1985)	3	6	2	3	5	3	5	5	1	2	5	4	2	6	3	2	8	1
A-2 (peak 1985-1990)	3	5	3	3	4	4	6	3	2	2	4	5	2	6	3	2	7	2
A-3 (peak 1990-2000)	2	7	2	4	4	3	3	5	3	3	6	2	3	7	1	1	9	1
A-4 (peak after 2000)	3	5	3	2	4	5	4	4	3	3	6	2	2	8	1	1	9	1
C-1 (air travel)				3	4	3	2	5	3	4	5	1	2	7	1	1	8	1
C-2 (personal auto)	3	4	3				1	5	4	2	7	1	0	8	2	1	8	1
C-3 (heating oil)	3	5	2	4	3	3				2	6	2	3	6	1	3	6	1
C-4 (ind. fuel oil)	2	6	2	1	5	4	1	5	4				2	7	1	3	5	2
C-5 (chem. feed)	2	6	2	2	5	3	1	6	3	2	5	3				1	8	1
C-6 (marine fuel)	3	4	3	2	6	2	2	5	3	2	6	2	3	6	1			

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TABLE 18-7 (continued)

	Excess of + over - Responses					
	C-1	C-2	C-3	C-4	C-5	C-6
A-1	1	0	4	-2	-1	1
A-2	0	-1	4	-3	-1	0
A-3	0	1	0	1	2	0
A-4	0	-3	1	1	1	0
C-1	X	0	-1	3	1	0
C-2	0	X	-3	1	-2	0
C-3	1	1	X	0	2	2
C-4	0	-3	-3	X	1	1
C-5	0	-1	-2	-1	X	0
C-6	0	0	-1	0	2	X

Note: one ER participant did not respond to the "C" items (i.e. the impact of a "C" event on other "C" activities).

TABLE 18-8

DOE/OUTSIDE GROUP'S CONDITIONAL RESPONSES TO "C" EVENTS

Activity Impacted by Event	Fuel Use Curtailment Event																	
	C-1 (air travel)			C-2 (personal auto)			C-3 (heating oil)			C-4 (ind. fuel oil)			C-5 (chem. feed)			C-6 (marine fuel)		
	+	0	-	+	0	-	+	0	-	+	0	-	+	0	-	+	0	-
A-1 (peak by 1985)	1	6	3	2	3	5	2	5	3	2	5	3	2	6	2	2	7	1
A-2 (peak 1985-1990)	1	6	3	1	3	6	0	7	3	0	6	4	1	7	2	0	8	2
A-3 (peak 1990-2000)	1	7	2	2	4	4	1	6	3	2	5	3	0	8	2	0	8	2
A-4 (peak after 2000)	3	6	1	4	3	3	1	7	2	3	4	3	1	7	2	1	7	2
C-1 (air travel)				3	2	4	3	5	1	1	5	3	1	7	1	2	6	1
C-2 (personal auto)	2	5	2				3	6	0	2	6	1	1	8	0	2	7	0
C-3 (heating oil)	2	7	0	1	7	1				2	4	3	2	6	1	2	6	1
C-4 (ind. fuel oil)	2	7	0	2	5	2	2	5	2				3	4	2	1	7	1
C-5 (chem. feed)	2	7	0	2	5	2	2	5	2	2	5	2				2	7	0
C-6 (marine fuel)	0	8	1	1	7	1	0	8	1	2	6	1	3	5	1			

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TABLE 18-8 (continued)

	Excess of + over - Responses					
	<u>C-1</u>	<u>C-2</u>	<u>C-3</u>	<u>C-4</u>	<u>C-5</u>	<u>C-6</u>
A-1	-2	-3	-1	-1	0	1
A-2	-2	-5	-3	-4	-1	-2
A-3	-1	-2	-2	-1	-2	-2
A-4	2	1	-1	0	-1	-1
C-1	X	-1	2	-2	0	1
C-2	0	X	3	1	1	2
C-3	2	0	X	-1	1	1
C-4	2	0	0	X	1	0
C-5	2	0	0	0	X	2
C-6	-1	0	-1	1	2	X

Note: one DOE/outside group participant did not respond to the "C" items (i.e. the impact of a "C" event on other "C" activities).

- (1) the participants suffered from fatigue and, in cases of doubt, found "o" to be a conveniently neutral response.
- (2) the required adjustment to previously estimated subjective probabilities was hard to make.
- (3) some participants may have felt either "I've already given my estimate, and I don't intend to change it" or "I don't accept the assumption that I'm being asked to make. Therefore, my previous estimate stands."
- (4) it was difficult to make causal or correlative linkages between events, i.e. in the absence of explicit and predefined causalities the participants would have to create their own mental models using their own assumptions. Within practical time constraints, this may have been very difficult.

The responses of both test groups to the "A" events (see Tables 18-5 and 18-6) were very similar. However, as for the first questionnaire, individual responses within each group varied greatly. As shown in the lower portion of each table, the excess of "+" over "-" responses declined as the conditioning event, the peaking of world crude oil production, is assumed to occur later in the future. The pattern of response in Tables 18-5 and 18-6 is what would be expected (logically) from the results of the first questionnaire, thereby suggesting that this segment of the second questionnaire was clear to the majority of respondents in both test groups.

The responses of the test groups to the "C" events were quite similar in the case of 47 impacts, but differed for the thirteen impacts recorded in Table 18-9. The reasons for these differences are not known beyond the obvious implication that the assumptions made by the test groups must have differed on the average. For example, the change in the mean response of the ER group to an assumption of air travel curtailment was that a peaking of world oil production by 1985 would be more likely, whereas the DOE/other group's mean response was in the opposite direction. A very important distinction may underlie these differences in perception:

- on the average, the ER group may have felt that something as serious (in a social and economic sense) as the curtailment of air travel would not occur unless world oil production had peaked or was expected to do so imminently; i.e. a correlative rather than a causative linkage may have been assumed.
- on the average, the DOE/other group may have felt that curtailment of air travel would avert or postpone the peaking of world oil production; i.e. a causative linkage may have been assumed.

*Nevertheless, one of the principal values of the cross-impact analysis is to generate the thinking required to estimate impacts.

TABLE 18-9

DIVERGENCIES IN RESPONSES OF ER AND DOE/OTHER
GROUPS TO "C" EVENTS (SEE TABLES 7 AND 8)

● Assumed event C-1 (air travel curtailed)

Impacted event A-1 (world oil production peaks by 1985)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	3	6	2	1
DOE/outside group	1	6	3	-2

● Assumed event C-2 (personal auto use curtailed)

Impacted event A-1 (world oil production peaks by 1985)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	3	5	3	0
DOE/outside group	2	3	5	-3

Impacted event A-2 (world oil production peaks between 1985 and 1990)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	3	4	4	-1
DOE/outside group	1	3	6	-5

Impacted event A-3 (world oil production peaks between 1990 and 2000)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	4	4	3	1
DOE/outside group	2	4	4	-2

Impacted event A-4 (world oil production peaks after year 2000)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	2	4	5	-3
DOE/outside group	4	3	3	1

Impacted event C-4 (curtailment of ind. fuel oil use)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	1	5	4	-3
DOE/outside group	2	5	2	0

TABLE 18-9 (continued)

- Assumed event C-3 (domestic heating oil use curtailed)
Impacted event A-1 (world oil production peaks by 1985)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	5	5	1	4
DOE/outside group	2	5	3	-1

Impacted event A-2 (world oil production peaks between 1985 and 1990)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	6	3	2	4
DOE/outside group	0	7	3	-3

Impacted event C-1 (air travel curtailed)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	2	5	3	-1
DOE/outside group	3	5	1	2

Impacted event C-2 (personal auto use curtailed)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	1	5	4	-3
DOE/outside group	3	6	0	3

Impacted event C-4 (ind. fuel oil use curtailed)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	1	5	4	-3
DOE/outside group	2	5	2	0

- Assumed event C-4 (ind. fuel oil use curtailed)
Impacted event C-1 (air travel curtailed)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	4	5	1	3
DOE/outside group	1	5	3	-2

- Assumed event C-5 (chemical feedstock use curtailed)
Impacted event A-3 (world oil production peaks between 1990 and 2000)

	<u>+</u>	<u>0</u>	<u>-</u>	<u>+/- Δ</u>
ER group	3	7	1	2
DOE/outside group	0	8	2	-2

Almost all of the other divergencies may be rationalized in the same way, but the data do not permit this rationalization to be confirmed.

On the average, the ER group judged that curtailment of personal auto use would lessen the chance of curtailment of the use of industrial fuel oil, whereas the DOE/outside group's response was neutral. Apparently, the ER group's judgment was that saving automotive fuel would obviate or mitigate the need for saving fuel oil.

All of the divergencies in response to event C-3 (assumed curtailment of heating oil use) may be rationalized on the basis that the ER group may have been more concerned with correlation or association than with causation. This also applies the divergent responses to events C-4 and C-5.

6. Conclusions

The results obtained from the two questionnaires provide experimental evidence that there is considerable uncertainty about energy futures when measured in terms of individual perceptions. Because of the relatively small size of the test groups and in recognition of imperfections in the tests themselves, the results should be regarded as indications rather than as having been validated scientifically. Such validation would require further work, which may be justified if the indications are judged to be sufficiently interesting and important to be worth confirming or disproving. The principal inferences, or tentative conclusions, are as follows:

- (1) The patterns of response by ER groups and by a DOE/outside group were very similar, as were the mean responses of each group.
- (2) Within each group there were considerable differences in response that, in the case of value laden issues like personal automobile use, amounted to polarization. (The same polarization was observed in both the ER and DOE/outside groups.)
- (3) Some individuals in each group had difficulty with probabilistic forecasting. In part, this difficulty is attributable to deficiencies in the design and wording of the questionnaires. In part, however, the difficulty appears to reflect lack of familiarity with the subject.
- (4) Extreme care is needed in the wording of questions and instructions. Even the slightest ambiguity leads to misunderstandings.
- (5) For the cross-impact responses, it is possible that the ER group's response weighted correlation or association of events as much or more than causation. The latter appears to have been the guiding perception of the DOE/outside group. This was the one respect in which a material difference was observed between the two test groups.

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- (6) Except for uncertainty introduced by ambiguous wording (which does not appear to be the principal variable), it appears that the within-group differences are attributable to different assumptions. The limited experiment did not permit these assumptions to be made explicit.

Without any supporting evidence from the experiment itself, it is believed that the assumptions made by groups and individuals about energy futures and priorities are important to the resolution of institutional problems. Put differently, different assumptions lead to differing perceptions of priority. Hence, it may be difficult to resolve conflicts in priority without first identifying and trying to resolve the differing assumptions that underlie the conflicts.

Figure 18-1

POOLED RESPONSES TO "C" QUESTIONS

○ Shows position of pooled curtailment rating for each type of petroleum use on scale of 1 (= highest curtailment priority) to 6 (= lowest curtailment priority).

() Shows number of respondents who assigned the pertinent curtailment priority rating to each petroleum use.

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16. Abstracts <p>A planning study has been made for DOE on alternate fuels for non-highway transportation (aircraft, rail, marine and pipeline). The purpose of the study was to provide DOE with a recommendation of what alternate fuels may be of interest to non-highway transportation users from now through 2025 and to recommend R&D needed to allow non-petroleum derived fuels to be used in non-highway transportation.</p> <p>In the near term (present 1985), there is unlikely to be any major change in the fuels used in any of the four modes of transportation except that the average quality of the marine fuel is likely to get worse. In the mid-term period (1985-2000), there will be a transition to non-petroleum fuels, based primarily on shale oil derived liquids assuming a shale oil industry is started during this time.</p> <p style="text-align: center;">(over)</p>					
17. Key Words and Document Analysis. 17a. Descriptors <table border="0" style="width: 100%;"> <tr> <td style="vertical-align: top;"> Alternate Fuels Marine Aircraft Pipeline Railroads Energy Supply/Demand Military Considerations </td> <td style="vertical-align: top;"> International Considerations Institutional Issues Probabilistic Forecasting Cross-Impact Analysis </td> </tr> </table>				Alternate Fuels Marine Aircraft Pipeline Railroads Energy Supply/Demand Military Considerations	International Considerations Institutional Issues Probabilistic Forecasting Cross-Impact Analysis
Alternate Fuels Marine Aircraft Pipeline Railroads Energy Supply/Demand Military Considerations	International Considerations Institutional Issues Probabilistic Forecasting Cross-Impact Analysis				
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16. Abstracts (cont.)

The future outlook for possible prime movers and potential fuel sources for the long term (2000+) is as follows. In the marine area, steam engines burning coal or diesel engines with unrefined shale oil or coal slurries are the prime candidates. With the aircraft gas turbine, either synthetic liquids from shale or coal would appear to be the most desirable fuels. Railroads will probably remain with the diesel/electric prime mover using shale oil as a source of distillate. Pipelines will probably use electric motors as the major type of prime mover.

This Apperfix covers the demand-related issues and the institutional problems.

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