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# Alternative Energy Sources for Non-Highway Transportation

## Technical Section

June 1980

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

Contract No. DE-AC05-77CS05438

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Office of Transportation Programs
Washington, D.C. 20585

Prepared by
Exxon Research and Engineering Company
Government Research Laboratories
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Contract No. DE-AC05-77CS05438

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# Acknowledgment

This report was edited by E. N. Cart, Jr. and is based on work performed by E. N. Cart, Jr., D. Carter, A. R. Cunningham, M. H. Farmer, W. Herbst, B. Kraus, E. M. Magee, E. W. Nicholson and J. Percival.

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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. INTRODUCTION, OBJECTIVES AND STRUCTURE OF REPORT

## Introduction

The United States faces a serious problem with regard to petroleum and natural gas. These two fuels presently supply essentially all of the energy needs for the non-highway transportation system (aircraft, rail, marine and pipeline). While the non-highway modes of transportation accounted for only around 25% of the transportation energy usage in 1975, these modes are important in the handling of freight. Any disruption in the movement of freight due to non-availability of fuels would have a devastating effect on the U.S. economy.

Domestic production of petroleum and natural gas has peaked and worldwide production is forecast to peak by the end of the century. Petroleum imports are, therefore, not the long-term solution, and the U.S. and other countries need to prepare now for the "post-petroleum" fuel era. With the long lead times to develop new engines and alternate fuels supplies, serious consideration needs to be given now to future fuels for each of these modes.

The study was divided into four major areas: (1) a literature review of alternate fuels and prime movers; (2) a preliminary screening of various alternate fuels and prime movers which established the basic data for the study and which allowed the number of fuels to be narrowed down for the detailed evaluation phase; (3) a detailed evaluation of the four modes of transportation from the standpoint of the user, the fuel supplier, and the engine designer; and (4) an evaluation of the demand-related issues.

## Objectives

The overall objectives for the study were:

1. Examine choices for alternate fuels in each mode

   Present (now to 1985)
   Mid Term (1985-2000)
   Long Term (2000+)

2. Recommend R&D ideas for each mode

The objectives for the preliminary screening phase were as follows:

1. Develop a method of ranking alternate fuels and prime movers.

2. Establish the basic data on fuels and prime movers to be used in the preliminary screening and the detailed evaluation in the following areas.

Fuels

- Cost to produce and transport fuels
- Energy efficiency to produce fuels
- Environmental impact in manufacture
- Fuel properties
- Fuel/prime mover capability
- Logistics considerations

Prime Movers

- Efficiency of various engines
- Environmental impact in use
- Characteristics of engines

3. Narrow down the list of alternate fuels/prime movers for a more in-depth study.

The objectives for the detailed evaluation phase were as follows:

1. Make a detailed evaluation of the most likely candidates that were identified in the preliminary screening for each mode of non-highway transportation. This will include determining the overall economics of using the various fuels in the different prime movers.

2. Develop ranking of fuel choices and prime movers by mode and time frame.

3. Develop R&D suggestions for each mode of non-highway transportation.

## Structure of Report

This report is in nine sections. Section 2 gives the overall summary and conclusions, the future outlook for each mode of transportation and the R&D suggestions by mode of transportation. Section 3 covers the preliminary screening phase and includes a summary of the data base used in this study. Section 4 presents the methodology used to select the fuels and prime movers for the detailed study. Sections 5-8 cover the detailed evaluation of the pipeline, marine, railroad and aircraft modes of transportation. Section 9 covers the demand related issues.

## 2. SUMMARY AND CONCLUSIONS, FUTURE OUTLOOK FOR FUELS FOR EACH MODE AND R&D SUGGESTIONS

### 2.1 Preliminary Screening of Fuels and Prime Movers

Eighteen different alternative fuels were considered in the preliminary screening, from three basic resource bases, as shown in Table 2-1. Coal can be used to provide 13 of the fuels; oil shale was the source for three of the fuels and biomass provided the resource base for two fuels not provided from coal. In the case of biomass, six different fuels were considered. Nuclear power and direct solar radiation were also considered.

The eight prime movers that were considered in the preliminary screening are shown in Table 2-2. Most of these are used to some extent currently in one or more of the modes, except the last three listed.

A methodology was developed to rank the various alternate fuels and to select which fuels and prime movers should be considered for detailed evaluation for each mode of transportation. The four major factors considered were:

1. Fuel Manufacture
   - Economics of production and transportation
   - Overall energy efficiency
   - Environmental impact in production
2. Fuel performance from designer/user viewpoint
   - Toxicity
   - Safety
   - Materials compatibility
   - Storage requirement
   - Convenience in handling and storage
   - Environmental impact during use
3. Compatibility of the fuels and prime movers
4. Fuel logistics factors
   - Availability by 1990
   - Compatibility with present system
   - International considerations

## TABLE 2-1

### Eighteen Different Fuels/Energy Carriers Considered in Preliminary Screening

**Coal Resource Base**

1. Coal
2. Coal/Oil Slurry - (petroleum, shale oil, or coal liquids)
3. Coal/Methanol Slurry
4. Coal Liquids--unrefined
5. Coal Liquids--Distillate/Gasoline
6. Methane (SNG)
7. Methanol
8. Ammonia
9. Methylamine
10. Hydrazine
11. Acetylene
12. Hydrogen (Energy Carrier)
13. Electricity (Energy Carrier)

**Oil Shale Resources**

14. Raw Shale Oil
15. Syncrude
16. Syncrude--Distillate/Gasoline

**Biomass**

Methanol - (Sugarcane, Solid Waste, OTEC)
17. Ethanol - (Corn, Sugarcane)
Ammonia
18. Oil from Solid Waste
Electricity--Solar
Methane

## TABLE 2-2

## Prime Movers Considered in Preliminary Screening

1. Boiler/Steam Turbine
2. Gas Turbine--Open Cycle
   --Closed Cycle
3. Diesel--Low Speed
   --Medium Speed
4. Otto Cycle--Spark Ignited
   --Stratified Charge
5. Electric Motor
6. Stirling Engine
7. Free Piston
8. Fuel Cell/Electric Motor

Based on these criteria, the following overall fuel rankings were obtained:

### TABLE 2-3

### Overall Fuel Rankings for Non-Highway Transportation

| Fuels | |
|---|---|
| Shale Liquids--Gasoline | Prime Candidates |
| Distillate | |
| Coal/Oil Slurry | |
| Coal | |
| Raw Shale Oil | |
| Coal Liquids--Distillate | |
| Gasoline | |
| Methane ($\ell$) | |
| Oil--From Organic Waste | Probably of Interest |
| Ethanol--Corn | |
| Sugar Cane | |
| Methanol--Coal | |
| Coal/Methanol Slurry | Borderline--May be Special Reasons Why These Would Look Attractive |
| Electricity--Coal/Nuclear | |
| Methanol--Biomass | |
| Hydrogen--Coal | |
| Hydrogen--Electrolysis | |
| Ammonia--Biomass | Clearly Not Attractive |
| Coal | |
| Hydrazine | |
| Methylamine | |
| Acetylene | |

The fuels that were considered further for each mode of transportation are shown below.

## TABLE 2-4

## Fuels Considered in Detailed Evaluation Phase

| | Railroads | Pipelines | Aircraft | Marine |
|---|---|---|---|---|
| **Shale--Distillate** | X | X | X | X |
| **--Gasoline** | | X | | |
| **Coal--Distillate** | X | X | X | X |
| **--Gasoline** | | X | | |
| **Raw Shale Oil** | X | X | | X |
| **Methane (ℓ)** | X | X | X | X |
| **Hydrogen (ℓ)** | | | X | |
| **Ethanol** | X | X | | |
| **Methanol** | | X | | |
| **Coal/Oil Slurry** | X | | | X |
| **Coal** | X | | | X |

The list in Table 2-4 gives an indication of which fuels would have the potential for use in more than one mode of transportation. Liquids from shale oil, coal liquids, and methane from coal, are the only fuels that could possibly be considered for use in all four modes.

For each mode of transportation, several different types of prime movers were considered, as shown below.

TABLE 2-5

Prime Movers Considered in Detailed Evaluation

| | **Railroads** | **Pipelines** | **Aircraft** | **Marine** |
|---|---|---|---|---|
| **Diesel** | X | X | | X |
| **Steam Engine** | X | | | X |
| **Stirling Engine** | X | | | |
| **Gas Turbines** | X | X | X | X |
| **Fuel Cells/Electric Motor** | X | X | | X |
| **Otto Cycle** | | | | |
| **- Stratified Charge** | | X | | |
| **- Spark Ignited** | | X | | |
| **Free Piston** | | | | X |

The basic data on fuels and prime movers for the preliminary screening and the remainder of the program was established and is summarized in this report, with the details in the Appendix (Volume IIIA-D).

The summary and conclusions, the future outlook for the near, mid and long term, and R&D suggestions are given by mode of transportation. All cost are in terms of 1980 constant dollars.

## 2.2 Pipeline

### Summary and Conclusions

### Liquid Pipelines

- The electric motor is expected to be the most economical prime mover over the size range considered, 500 to 5000 horsepower, provided the cost of the fuel used for a diesel or gas turbine costs more than \$4/M(1) BTU and that electric power is available at the site.
- If the cost of liquid fuels is less then about \$4/M BTU than either a diesel or a gas turbine would give a lower total annual cost. All of the alternate fuels considered as possible fuels for pipeline service have a cost greater than \$4/M BTU, therefore, it is unlikely any of these would be used in place of electric motors, unless the cost of providing electric power to a site was very high.
- The choice between a diesel engine and a gas turbine driver would depend on the size. At the 500 HP size the two types are about equal in annual cost. Above this size range the gas turbine is cheaper to operate. The gas turbine has a lower initial investment and maintenance cost but the fuel requirements are greater than for a diesel engine.
- In addition to being more economical on an annual cost basis, the electric motor is also more attractive from the initial cost standpoint; can be controlled from remote locations, and is preferred from a total energy conservation standpoint. If the electric power is generated by coal or nuclear power, then the liquid pipeline energy requirements can be converted to non-petroleum sources.
- There is no incentive to consider the use of fuel cells for liquid pipeline applications.

### Gas Pipelines

- The most economical and overall energy efficient prime mover-fuel combination is the electric motor using coal or nuclear energy to generate the electricity, as long as the fuel cost is greater than \$4-5/M BTU. This means that it is more economical to use an electric motor drive to compress SNG or hydrogen rather than a gas turbine or gas reciprocating engine using SNG or hydrogen from coal as the fuel. The cost of both of these fuels is expected to exceed \$5/M BTU.
- With a low or medium BTU gas it may be more attractive to use a gas turbine, depending on the cost of electricity. A site specific study would be required to answer this question.

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(1) Million in this report.

- In the smaller size ranges of 500 HP, the annual cost of operation for an electric motor, a gas turbine, and a gas engine are essentially equal. As the size of the driver increases, the electric motor becomes more attractive.

- On an annual cost basis, there is a small advantage for a molten carbonate fuel cell compared to a gas turbine and gas engine. There is no advantage for a $H_3PO_4$ electrolyte fuel cell for gas pipeline application.

- Molten carbonate fuel cells are not projected to be as attractive as electric motors for gas compression at the investment level assumed in this study. A 25% reduction in investment would be required for the annual operating cost for a fuel cell system to breakeven with an electric motor drive.

- Fuel cells do have a significant advantage over gas turbines in fuel efficiency at part load. However, in actual practices, this situation is generally handled by adding compression capacity in increments and running all units at maximum capacity.

- There does not appear to be enough incentives for the use of fuel cells in gas transmission operations to justify supporting the development of fuel cells for this purpose alone. If fuel cells are commercialized for other applications, their potential for use in pipeline services should be considered when better information on costs and efficiencies become available. It is not expected that molten carbonate fuel cells will be available commercially before 1990. Presumably, these conclusions will be firmed up by the contracted study on applications of fuel cells to pipeline operations being made for the Department of Energy.

### Future Fuels and Prime Movers - Pipeline

The outlook for future fuels and prime movers for liquid and gas pipelines is summarized below.

### Future Fuels and Prime Movers for Pipelines

| | Prime Mover | Fuel |
|---|---|---|
| Liquid Pipelines | | |
| Major User | Electric Motor | Electricity from Coal Fired Power Plant |
| Very Limited Use | Advanced Gas Turbine | Raw Shale Oil<br>Shale Oil Liquids<br>Coal Liquids<br>Alcohol |
| Even More Limited Use | Diesel | Shale Oil Liquids<br>Upgraded Coal Liquids |
| Gas Pipelines | | |
| Major User | Electric Motor | Electricity from Coal Fired Power Plant |
| Limited Use | Advanced Gas Turbine | Low/Medium BTU Gas |

## R&D Suggestions - Pipeline

Since the most likely prime mover to be used for future pipelines is the electric motor, the amount of alternate fuels R&D is fairly limited. From the pipeline companies viewpoint, the more important future issues they will be facing are possible regulatory constraints and pipeline construction technology for extreme environments.

Some possible areas where R&D may be useful are as follows:

- Continue to make improvements in existing gas turbine drives to increase the efficiency of the current engines, e.g. regeneration, bottoming cycles, etc.
- Investigate ways to incorporate bottoming cycles in the current reciprocating gas engine.
- Determine if raw shale oil liquids can be used in the types of diesel engines used in pipeline service.
- Follow the R&D activity in molten carbonate fuel cells. If major cost reductions take place, relative to the cost of electric motors, this type of fuel cell may look attractive longer range in gas pipeline service.
- It may be worthwhile to make a planning study to investigate a coal-fired cogernation station for a very large pumping station. It would appear that electric power generated from a large coal fired plant would be more attractive.

## 2.3 Marine

## Summary and Conclusions

- For new, large (45,000 Hp) vessels, the most economical and energy efficient prime mover/fuel combination is a steam engine using coal as the fuel.
- Medium size vessels (9500 Hp range) with load factors in the 60-90% range would find diesel more attractive if they can get a liquid fuel for less than $4.50/MBTU. If the liquid fuel cost more than this coal would be more attractive.
- Small size vessels (4500 Hp range) will probably stick with diesel powered engine up to a fuel cost of $5-6/MBTU.
- Diesel engines and regenerative gas turbines would look attractive at a high load factor if a fuel can be obtained for $3/MBTU. The only possible fuel that could fall in this category would be an unrefined shale oil.
- Coal-oil slurry is another possible candidate, especially if a slow speed diesel could be modified to work on a coal-oil slurry. This is especially true for smaller size ships.
- The use of fuel cells does not appear to be attractive for this application.
- The incentive over a coal-steam plant to make coal work in a gas turbine or diesel is insufficient to justify R&D.

- The incentive over coal-steam is also too small to justify R&D on stirling engines in the 10,000 Hp range.

- The incentive is small to improve the efficiency of a marine steam plant burning coal.

- Most current marine prime movers could operate on an unrefined shale oil.

- If $LCH_4$ is available as boil-off, the preferred engine would be a steam fired turbine or a gas turbine. The choice depends on ratio of boil-off to total fuel and size of ship.

- Phase out of liquid fueled ships will be very long; they consume very little of world's energy, they consume the lowest grade of petroleum which can be made from poor quality crudes - at small cost.

- Future prime movers used in international marine trade must be able to find usable fuels worldwide.

- For coastal trade vessels, new construction would favor coal-fired steam turbines except for those vessels carrying Alaskan crude. Regenerative gas turbines or combined gas turbine/steam turbine engines would be a possibility on this route.

- Great Lake vessels may also find steam turbines attractive if environmental restrictions would not limit the use of coal. Use of shale oil distillate or Canadian Tar Sand Oil in a diesel is another possibility.

- Tug boats on inland waterways will continue to use medium-to-high speed diesel engines, with distillate from shale oil.

- Pleasure craft propulsion systems will probably develop in a paralle fashion to highway traffic. Fuel possibilities include alcohols and shale or coal derived gasolines.

### Outlook for Future Fuels and Prime Movers - Marine

The outlook for future fuels and prime movers in the marine area is summarized below.

### Near Term (Present - 1985)

- Continue on petroleum, average quality likely to get worse.

### Mid Term (1985-2000)

- If shipbuilding continues -- late in this period:
  - + Coal fired, steam power plant will be used, particularly for ships in international coal transportation.
  - + Coal/oil slurries may also be used in steam ships. May also be attractive in low speed diesel if it would work in this type of engine.
  - + For smaller size vessels, unrefined shale oil could be used in diesels. If coal/oil slurries would work, it may also be used.

Long Term (2000+)

- + Most new construction of large ships will be using coal-steam boilers.
- + Smaller size vessels will continue to use diesel engines with shale liquids as fuel.

R&D Suggestions - Marine

Some possible R&D ideas in the marine area are as follows:

- A study on coal fired boilers for marine vessels
  - + Type of boilers - e.g. is FBC a possibility?
  - + Firm up cost
  - + What are the size constraints in various types of vessels
  - + Are there any environmental constraints
- Study on logistics of coal supply for vessels - it is feasible; is space available?
- Study on coal/oil slurry for existing vessels - could it be used in current boilers? What are the storage requirements? Is it possible to modify a low speed diesel to burn a coal/oil slurry?
- Study on future market for various fuel in each class of vessels.
- Investigate the compatibility of various synthetic fuels with petroleum fuels, i.e. will a separate fuel system be needed?

## 2.4 Railroad

Summary and Conclusions

- Diesel/electric in current use is thermally efficient - idling time is costly in terms of fuel consumption.
- To compete with diesel electric, alternate must have advantage in one or more of following:
  1. Lower capital cost
  2. Ability to burn lower cost fuel than diesel fuel
  3. Higher thermal efficiency
  4. Lower maintenance cost
  5. Not require idling and thus save fuel cost

1. No alternates, likely to beat diesel electric on capital cost.

2. Steam and Stirling could burn coal - steam engine would have low efficiency - air pollution control would be critical.

3. Fuel cells more efficient and would not require idling. Phosphoric acid type fuel cell competitive if diesel fuel cost exceeds $6/MBTU.

4. Gas turbines not likely to be competitive due to fuel consumption at idle.

- Electrification option for freight must be considered for high population density areas, like North East corridor, if diesel fuel cost exceeds $8/MBTU.

## Outlook for Future Fuels and Prime Movers - Railroad

The outlook for future fuels and prime movers in the railroad area is summarized below.

### Near Term (Present - 1985)

- Unlikely to see any major fuel changes.
- Main efforts will be conservation.

### Mid Term (1985 - 2000)

- May start to see shale distillates used in freight and switching diesel.

### Long Term (2000+)

- Probably will still see diesel/electric with shale oil distillate.
- Other possibilities include: (low probability)
  - + Coal fired Stirling Engine
  - + Fuel cell with naphtha from shale or coal liquids
  - + Greater electrification in densely populated areas

## R&D Suggestions - Railroad

Some possible R&D ideas on fuels and prime movers for railroads are outlined below.

- Study on Stirling Engines burning coal - is this feasible from an environmental standpoint?
- Detailed study on fuels cells would appear warranted.
  - + Can weight and volume be accommodated?
  - + Would fuel cells be adversely affected by vibration, shocks, tilting, etc.?
  - + With molten carbonate cells - what safety problems are to be overcome?
- Assessment of environmental problems with diesel engines with synthetic fuels (PNA, $NO_x$ and $SO_x$, particulates).
- Tradeoff study between maintenance cost and amount of upgrading of shale oil required.

## 2.5 Aircraft

### Summary and Conclusions

- Based on the physical properties of the cryogenic fuels and the synthetic jet fuels considered, $LH_2$ has the highest heat of combustion on a weight basis, the highest specific heat (a measure of its efficiency as a coolant), but its disadvantages are its low density and resulting low volumetric heat content and its low boiling point.

- Liquid methane is 15% more energetic than Jet A on a weight basis, has a specific heat 1.7 times that of Jet A, and is six more dense than liquid hydrogen.

- Studies by Lockheed have shown that for a subsonic, 5500 miles, 400 passengers aircraft, the initial cost of the aircraft would be about the same for all three fuels ($LH_2$, $LCH_4$ and Jet A). The methane fueled aircraft characteristics fall between $LH_2$ and Jet A. A $LH_2$ fueled aircraft design is lighter, uses less fuel for a given flight, requires an engine with lower thrust and requires a shorter runway.

- The fuel cost, on a per flight basis for a subsonic aircraft, shows that shale oil derived Jet A would be the least costly, followed by a coal liquid jet fuel. $LCH_4$ would cost about double a shale oil. The $LH_2$ fueled aircraft would be the most expensive to operate - over three times what a shale oil derived Jet A would cost.

- Based on other studies by Lockheed, RAND, and Boeing, a synthetic jet fuel from shale oil would be the most economical fuel for future aircraft. Based on a life cycle comparison, the least costly is Jet A from shale oil, followed by Jet A from coal, with $LCH_4$ next and $LH_2$ the most expensive.

- For a supersonic aircraft (Mach 2.7, 4200 n. miles, and 234 passengers), the design advantages for LH2 are greater than for a subsonic aircraft. However, the fuel cost per flight still favors the Jet A case (shale oil first, followed by coal derived jet fuel), then $LH_2$.

- For supersonic aircraft, the cost of a Jet A fueled aircraft has been estimated to be about 35% higher than a $LH_2$ fueled aircraft. Including the cost of the aircraft and the potentially lower maintenance cost makes $LH_2$ more attractive than for the subsonic case, but still a shale oil derived Jet A would be the preferred fuel, with a coal derived fuel next.

- For a subsonic aircraft, $LH_2$ would have to cost about 47% less than the value used in this study to breakeven with a coal derived Jet A and 71% less to breakeven with a shale oil based Jet A on a fuel cost per flight basis. For a supersonic aircraft, the cost of $LH_2$ would have to be 17% less than the value used in this study to breakeven with a coal-derived jet fuel, and 45% less to breakeven with a shale oil derived jet fuel, considering the difference in the cost of the aircraft as well as the fuel cost difference.

- Liquid $H_2$ aircraft would appear to only be attractive for long range supersonic flights (>5500 miles).

- From the standpoint of natural resource requirements, considering the resources required from the mine to that used to power the aircraft, a shale oil derived jet fuel is the most efficient. $LH_2$ requires about double the amount of natural resource as shale oil.

- Lab tests have shown that acceptable jet fuels can be made from either coal or shale oil based resources. Production of aircraft fuels from shale oil should be more straight forward than from coal.

- Coal based (direct liquefaction) jet fuels will have poorer combustion properties than shale oil jet fuels due to the formation of naphthenes rather than paraffins when the coal liquids are hydrogenated.

- An economic comparison between upgrading fuels to meet current hydrogen levels and modifying the engine shows that there are incentives to develop an engine that can accept a poorer quality fuel.

## Future Outlook for Aviation Jet Fuels

The future outlook for aviation jet fuels is as follows:

### Near Term (Present - 1985)

- In the near term, it is unlikely that there will be any major changes in the specifications of commercial jet fuels. There may be minor changes to increase supplies if another embargo develops.

### Mid Term (1985 - 2000)

- In the mid term, 1985 - 2000, a broad cut fuel(1) may be used, depending on the outcome of the current NASA efforts in this area. By 1990, it is possible that a shale oil derived fuel may be used to a limited extent in commercial operation. Aircraft designed to utilize synthetic jet fuels are not likely till the year 2000.

### Long Term (2000+)

- The major replacement of petroleum based jet fuel in the long term (2000) is most likely to be shale oil derived jet fuel, with some coal liquids from indirect liquefaction possible. It is unlikely that $LH_2$ or $LCH_4$ will be widely used on commercial aviation, unless there is a strong demand for very long distance supersonic flights (> 5500 miles).

## R&D Suggestions - Aircraft

Some possible areas where R&D may be useful are as follows:

- Studies should be made to define the potential for $LH_2$ and $LCH_4$, using

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(1) See page 8-58 for definition and possible specification.

fuel cost information in this study. This would determine the break-even distance for supersonic aircraft and the speed for $LH_2$ to break-even with shale oil derived jet fuel.

- It would appear that coal liquids produced via the indirect method would have more attractive physical properties than those produced via direct liquefaction. Studies should be made to improve the yield of distillates via Fischer-Tropsch synthesis.

- If coal liquids are used as aircraft fuels, the storage stability of coal liquids (direct liquefaction ) hydrotreated to various levels should be determined.

- Studies should be made on engines that could operate with higher aromatic jet fuels. These same engines should be tested with higher nitrogen level fuels to see if they are also effective in reducing $NO_x$ emissions.

- Economic comparisons should be made to see if it would be more attractive to modify the fuel system or upgrade coal or shale based fuels to meet the current thermal stability standards.

- Processing alternates (such as chemical treating, clay filtering, etc.) to severe hydrotreating to improve storage and thermal stability of shale oil derived fuels should be investigated.

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# 3. PRELIMINARY SCREENING OF ALTERNATE FUELS AND PRIME MOVERS - DATA BASE FOR FUELS AND PRIME MOVERS

In the following sections, a summary of the data base used in this study on the various fuels and prime movers is given. Additional details are in Volume III with the specific section indicated.

## 3.1 Background and Alternate Energy Forms

### 3.1.1 Prime Movers and Fuels Used in Non-Highway Transportation (Volume IIIA - Section I)*

The background section covers the prime movers and fuels currently in use in each mode of non-highway transportation and the critical fuel properties. Only the highlights are given here. Additional details, including current fuel specifications are given in Volume IIIA.

#### 3.1.1.1 Aircraft Engines and Aviation Fuels

The principal prime mover for aircraft is the aviation gas turbine, which employes the basic Brayton thermodynamic cycle. Today's commercial and military aircraft inventory includes a variety of engines, which fall into six basic types: (1) turbojet, (2) turboprop, (3) turboshaft, (4)turbofan, (5) afterburning turbojet, and (6) afterburning turbofan. Details on each of these engine characteristics and the critical engine components are given in Volume IIIA.

In 1976, jet fuel accounted for 94% of the fuel used by domestic civil aviation. Three jet fuel types are in wide use throughout the free world -- (1) Jet A, a kerosene based fuel used by most of the commercial airlines; (2) JP-4, a blend of kerosene and gasoline, used by the military; and (3) JP-5, used by the Navy for ship based aircraft. The fuel characteristics and their potential impact on the engine performance are summarized below.

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*Refers to Section in the Appendix Volume where additional details can be found.

## FUEL CHARACTERISTICS AND POTENTIAL IMPACT

| Combustion System | Principal Quality Feature |
|---|---|
| • Combustion Efficiency<br>• Combustion Stability<br>• Inition (Ground and Attitude)<br>• Size, Weight, Cost<br>• Durability/Maintainability/Reliability<br>• Exhaust Emission | Viscosity<br>Hydrogen Content<br>Aromatic Content<br>Vapor Pressure<br>Flash Point<br>Distillation Characteristics |
| **Fuel System** | |
| • Fuel Tanks<br>• Piping, Valves, Pump, Meters<br>• Oil/Fuel Heat Exchangers<br>• Fuel Injection Equipment | Aromatics<br>Olefins<br>Thermal Stability<br>Freeze Point<br>Gum |

### 4.1.1.2 Marine Prime Movers on Marine Fuels

The principal prime movers at sea currently are steam turbines and diesel engines. Gas turbines are used to a very limited extent. Practically all new ships are diesel except for naval vessels which are equipped with gas turbines.

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. 28% vs. approx. 42% for diesel and approx. 32% for steam). Steam is relatively insensitive to fuel quality; diesel can burn a range of fuels--anywhere from relatively clean automotive diesel oil to heavy fuel oil (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 service. 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 have the maintenance performed by the engine manufacturer on shore. A gas turbine also has small space requirements compared to diesel and steam turbine and is relatively automatic, as is the diesel engine.

### 3.1.1.2.1 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:

| | | Application |
|---|---|---|
| Slow Speed | --Up to 500 RPM | - Marine & large stationary power plants |
| Medium Speed | --500 to 1000 RPM | - Railroad locomotives |
| High Speed | --Over 1000 RPM | - Trucks, buses, cars, small boats, construction machinery, etc. |

The fuel used in a diesel engine depends on a number of factors -- operating speed and load, engine size and design, atmospheric considerations, etc. The boiling range of distillate diesel fuel is approximately 300°F to 725°F. In some of the slow speed, marine engines, residual fuels, with a higher boiling point have been used. The performance features desired of all diesel fuels and the physical properties most directly related to them are summarized below:

| Performance Feature Desired | Indicated By |
|---|---|
| 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 | Gravity, °API |
| 8. Minimum effect on engine wear and deposits | Sulfur |

### 3.1.1.2.2 Steam Turbine

The steam turbine consist of a boiler and a turbine. In general, the main difference between a marine boiler and one used on land is that marine equipment is fired at a much higher heat release rate. Steam driven ships usually use heavy fuel oil. For international marine use, the heavy fuel oil has a minimum 11.5° API gravity spec, to insure good separation from sea water contamination.

### 3.1.1.2.3 The Gas Turbine Engine

A simple gas-turbine engine consists of a compressor, a combustion chamber and a turbine. 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 marine propulsion. 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 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.

### 3.1.1.3 **Railroad Prime Movers and Fuels**

The major 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 cost. The gas turbine has appeal as a locomotive power plant and Amtrak has taken delivery of the first of seven turbine-powered trains.

Information on diesel fuels and gas turbine fuels in general were covered in the section on marine fuels. Additional details are given in Volume IIIA - Section I.

### 3.1.1.4 **Pipeline Prime Movers and Fuels 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 AND NATURAL GAS BY PIPELINE

1970-71

| | $10^{12}$ BTU | % |
|---|---|---|
| Gas Reciprocating | 420 | 39 |
| Gas Turbine | 275 | 26 |
| Diesel | 45 | 4 |
| Electric | 328 | 31 |

### 3.1.1.5 Other Engines with Possible Application to Non-Highway Transportation

Engines which have not been discussed in the foregoing sections that have some possible application include (1) free piston engine, (2) Stirling engines, and (3) 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 are described briefly in Volume IIIA.

### 3.1.2 Alternate Energy Forms for Non-Highway Transportation (Vol. IIIA - Section 5)

Three alternate energy forms/prime movers were considered for potential use in non-highway transportation: (1) fuel cells, (2) nuclear power, and (3) solar--both thermal and electric. Of these three, only fuel cells appear potentially attractive enough as a potential prime mover to be considered in the detailed evaluation stage.

### 3.1.2.1 Possible Applications of Fuel Cells

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 fuel cell systems may operate at lower annual costs, including fuel cost, than other types of prime movers. In addition to the higher thermal efficiencies, compared to heat engines, some of the other advantages of fuel cells 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 are potentially low cost when mass production of modules to meet high demand rates becomes possible.

In a fuel cell, 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 in the form of low-voltage direct current. A number of cells are normally connected in series to provide up to 3000 volts DC from a system. This power can be inverted to AC and transformed to higher voltages in a power conditioning stage.

At the present time the only practical fuel cells known require hydrogen or $H_2/CO$ mixtures as fuel for the cells. Direct feeding of methanol and light hydrocarbons have been demonstrated, but are uneconomical due to the large amounts of platinum catalyst required. Thus, all fuel cells of commercial interest include a fuel preparation and conditioning section, where a steam reformer is used to convert the original fuel (hydrocarbon distillate, methane, hydrazine, alcohols, light hydrocarbons) to $H_2$ and CO.

The types of fuel cells considered in the preliminary screening are summarized below, along with the operating temperature and thermal efficiencies.

| Electrolyte | Operating Temp., °F | Thermal Effic., % (LHV) On $H_2$ | Thermal Effic., % (LHV) On Reformed Fuels |
|---|---|---|---|
| Before 1985 | | | |
| $H_3PO_4$ | 375 | 50 | 41 |
| After 1985 | | | |
| Alkali Metal Carbonates | 1200 | -- | 50 |
| KOH | 195 | 60 | 55 |

In the pre-1985 time period, only the phosphoric acid electrolyte system is far enough along in development to be considered. It is possible that either or both of the molten carbonate and the KOH electrolyte system could be commercially available in the 1985-2000 time period.

### 3.1.2.1.1 Applicability of Fuel Cells to Aircraft

Fuel cells will probably always have 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. This comparison is with old technology for the gas turbine; newer technology would even make fuel cells less attractive.

| Weights, pounds | Turboprop | Fuel Cells + Motors |
|---|---|---|
| Engines | 7,300 | |
| Fuel Cells | | 52,200 |
| DC Motors | | 153,000 |
| Fuel | 32,500 | 18,000 |
| TOTAL | 39,800 | 223,200 |

In view of the above comparison, no further consideration was given to the use of fuel cells in aircraft.

### 3.1.2.1.2 Applicability of Fuel Cells to Railroad Locomotives

In terms of energy consumed by the railroads, diesel-electric for freight service represents about 89% of the total energy consumed, so the comparison of fuel cells will be based on a comparison with diesel-electric for freight. The following tabulation compares the diesel-electric power system with a phosphoric acid fuel cell system.

FUEL CELL POWER FOR A LOCOMOTIVE

| Power Source | Diesel Electric | $H_3PO_4$ Fuel Cell + Reformer |
|---|---|---|
| Fuel | Distillate | Naphtha |
| Vol. Power Density-$ft^3$/kW | 0.4 | 1 |
| Weight Power Density-lbs/kW | 20 | 30 |
| Efficiency - %[a] | 33 | 40 |
| **Fuel Onboard (3300 HP Locomotive)** | | |
| Gallons | 4000 | 3670 |
| Cubic Feet | 535 | 490 |
| Pounds | 28000 | 22600 |

---

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

The power density (volume and weight) shown for the fuel cell is based on small unit data (10 kW). The 2900 kW units required for a locomotive should have much better power densities. Further study will be needed to determine the technical feasibility of substituting fuel cells for the diesel engine-alternator-rectifier system. The fuel cell system probably cannot be appreciably larger in volume than the current system since the overall dimensions of the existing locomotives are near the limits as constrained by tunnel and bridge clearances.

The major advantage for the fuel cells is in increased fuel efficiency. Improvement in the fuel efficiency for 33% currently to 40% with a phosphoric acid fuel cell could reduce the fuel requirement onboard from 4000 gallons to 3670 gallons, as well as reduce the operating costs for fuel.

### 3.1.2.1.3 Applicability of Fuel Cells in Marine Service

The major reason for considering fuel cells for marine application would be the improved thermal efficiency possible with fuel cells. Table 3-1 compares the thermal efficiencies of current marine engines, and future

## TABLE 3-1

## Possible Marine Power Plants

| | Fuel | Efficiency, % |
|---|---|---|
| **Current** | | |
| Steam turbine with reheat steam (1450 psig, 150°F) | Residium | 32-36 |
| Low-speed diesel | Residium | 39-41 |
| **Future Conventional** | | |
| Steam turbine with heat pressure, high temperature reheat (2400 psig, 1050°F) | Residium | 35-39 |
| Adiabatic diesel | Diesel | 49 |
| Naval Academy heat balance engine | Diesel | 43 |
| Heavy duty gas turbine, combined cycle | Residium | 36-40 |
| Closed cycle combustion turbine | Residium | 40-41 |
| **Fuel Cells** | | |
| Phosphoric Acid | Naphtha | 41 |
| Molten Carbonates | Distillate | 50 |
| Alkaline | Hydrogen | 60 |

conventional engines with fuel cells. As can be seen, with the phosphoric acid fuel cell, the overall efficiency is in the same range as the current low-speed diesel. Thus, there would be no economic advantage since the fuel cell would require a low-boiling, clean distillate fuel whereas the diesel can run on residium. If molten carbonate fuel cells or even alkaline fuel cells with 50-60% efficiencies become available in the 1985 plus period the increased efficiencies, compared to current and future conventional power plants, may justify the added cost of the equipment and make fuel cells a potential candidate for marine application. A comparison has been made between fuel cells and a 7000 HP diesel engine and with 30,000-40,000 HP steam turbine drives in the detailed evaluation (Section 6).

### 3.1.2.1.4 Applicability of Fuel Cells in Pipeline Service

Two possible fuel cell applications for pipelines were considered -- liquid pipelines and gas pipelines. In the case of a liquid pipeline, AC electric motors are the major prime mover. A rough comparison between cost of electricity from a fuel cell and the cost of electricity from a large power plant would indicate that fuel cells probably would be uneconomical. At one time, it was felt that a major advantage of fuel cells would be that the speed of the DC motor could be easily varied with liquid thruput. However, AC motors are now becoming available that provide for controlled phase changing so that power, and therefore throughput, can be adjusted as desired. In view of these factors, further consideration of fuel cells for liquid pipelines is not justified.

For gas pipeline, at least 93% of the compression energy is supplied by gas taken from the pipeline, using combustion turbines or Otto cycle reciprocating engines. Efficiencies of existing and possible future prime movers which can be utilized on gas pipelines are summarized in Table 3-2.

It is seen from the information in the table 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. A comparison has been made between fuel cells and advanced combustion turbines and advanced reciprocating engines of about 5000 HP size.

### 3.1.2.2 Potential Application of Nuclear Energy

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 the marine case, and to preheat the air to high temperatures to drive a gas turbine in the aircraft 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.

## TABLE 3-2

## Possible Power Plants for Gas Transmission Pipelines

| | Full-Load Efficiency % | Part-Load Efficiency % |
|---|---|---|
| **Combustion Turbines** | | |
| 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+ | |
| **Otto Cycle Reciprocating Engines** | | |
| Existing, new | 31-39 | |
| Combined-cycle with steam bottoming* | 38-43 | |
| Combined-cycle with organic bottoming* | 39-45 | |
| **Fuel Cells** | | |
| Phosphoric Acid | 41 | 43 |
| Molten Carbonates | 50 | 53 |

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*Retrofitting of bottoming cycles on existing machines appears possible.

### 4.1.2.2.1 Application of Nuclear Energy in 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. 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.

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

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.

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.

### 3.1.2.2.2 Application of Nuclear Energy in Aircraft

Nuclear-powered aircraft have been explored in considerable detail since the 1950's. 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. 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. 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.

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 unsurmountable 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.

### 3.1.2.3 Potential Application of 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 ultra-high 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 was considered. 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.

For marine application, to generate 10,000 SHP (continually for 24 hours) would require about 4.2 million $ft^2$ of collector surface for a photovoltaic efficiency of 10%. For a 485,000 DWT tanker the deck area is 0.24 million $ft^2$. Thus it is impractical to consider using solar photovoltaics for marine use. Similar calculations were made for railroad and pipeline applications and these indicated that it would be impractical to consider solar photovoltaics for these two modes of transportation.

### 3.1.2.4 Potential Application of Energy Storage Power Systems

A detailed evaluation of the prospects for energy storage devices were not considered in this study since the subject has been covered in a recent report by Bolger et al of Lawrence Livermore Laboratory*. Three general types of energy storage devices were considered: electrochemical, mechanical, and chemical/thermal. The general conclusions of the study were that the potential for appreciable energy savings in the non-highway sector by means of energy storage devices appear limited in the near- and mid-term. The duty cycles do not lend themselves well to this type of power systems. In the long-term, only hydrogen systems have potential, but as pointed out in this current study, the long-range cost of hydrogen would appear to limit this application. The conclusions for each mode from the LLL study are summarized below.

#### Rail

In heavy rail transportation, energy storage power systems are not practical as sources of long-distance propulsive power. However, they could be used in an auxiliary capacity in switching engines or in trains that start

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*"Application of Energy Storage Power Systems to Non Highway Transportation", Bolger, et at, UCRL-52333, May 1977.

and stop frequently and where the kinetic energy is a significant component of the total energy consumed and is worth storing and reclaiming. In rapid transit and light rail applications, energy storage devices could be used effectively to store and regenerate the kinetic energy now lost in braking. Flywheels could serve effectively in such applications. The principal barrier to implementation of this concept is the high initial cost of a regenerative braking system.

### Aviation

No potential application, except the use of hydrogen which is covered in the present study.

### Marine

Very little kinetic or potential energy is available for recovery relative to the total energy required during normal duty cycles.

### Pipeline

No attractive applications of energy storage power systems were identified.

## 3.2 Fuels Related Data Base

### 3.2.1 Economics of Fuel Manufacture (Volume IIIB - Section 6)

One major consideration in evaluating alternative energy sources is fuel cost. The cost of manufacturing the different fuels and energy carriers have been developed, based on published literature. Analysis of alternative production routes for any particular fuel is included, when this information is available. Also, included in the detailed write-up is a brief description of the processes used to manufacture the fuels, product yields and quality where applicable, and how the total cost may vary with plant size and raw material cost. The total cost are broken down into the three major components--(1) capital recovery, (2) feedstock cost, and (3) operating cost.

One problem with literature data is differences in economic bases, rates of return, plant sizes, etc. In this study, all of the costs have been adjusted to a common basis. The bases selected for this study are as follows:

- Money on 1980 dollar basis.
- Investments & operating cost escalation of 7%/year prior to 1980.
- Assumes 100% equity financing.
- Contingency of 25% on plant investment.

- Capital recovery factor (CRF) of 0.2$/year per dollar of investment. This roughly corresponds to a 10% discounted cash flow, which may be lower than the minimum acceptable to many companies today. Utility financing was also considered, where CRF factors can range from 0.155 to 0.17. Thus the value used in this study represents the lower end of acceptable industry return levels and is somewhat higher than typical utility recovery levels.
- Plant sizes:

| | |
|---|---|
| SNG | 250 MSCF/D |
| Liquids | 50 KB/D |
| Hydrogen | 880 MSCF/D |
| Methanol | 2000 Tons/D |
| Ethanol | 1500 Tons/D |

- By-product prices, coal cost, and electricity cost are given in the detailed report.

The costs for the various fuels are shown in Figure 3-1 on the basis of dollars per million BTU (lower heating value*) with cost increasing from left to right. The length of the bar in Figure 3-1 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 3-3 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 the next section.

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 3-2. 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.

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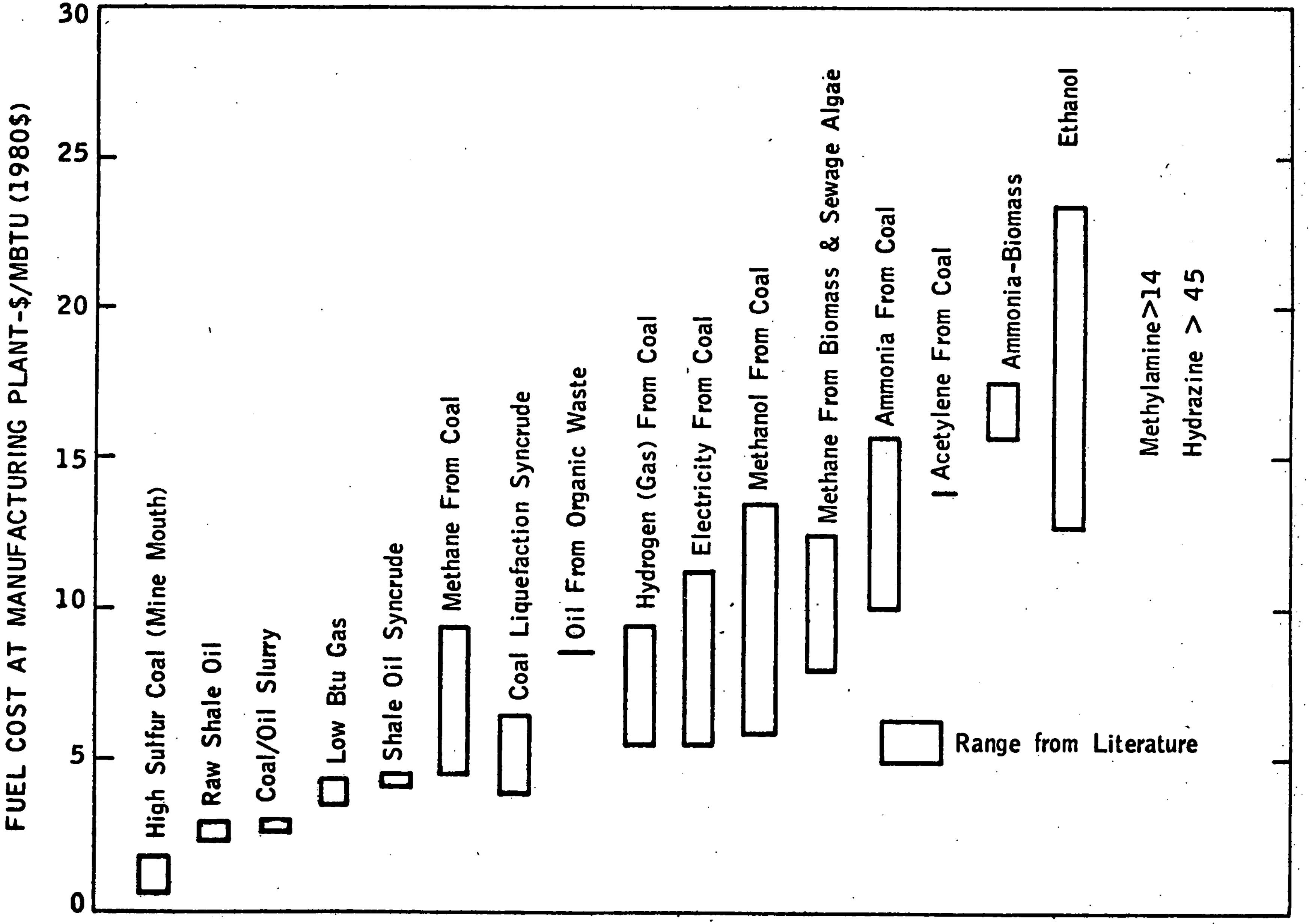
*Lower heating value because the latent heat of vaporization of water is not generally recoverable with transportation fuels.

FIGURE 3-1

ALTERNATE FUELS COSTS



## TABLE 3-3

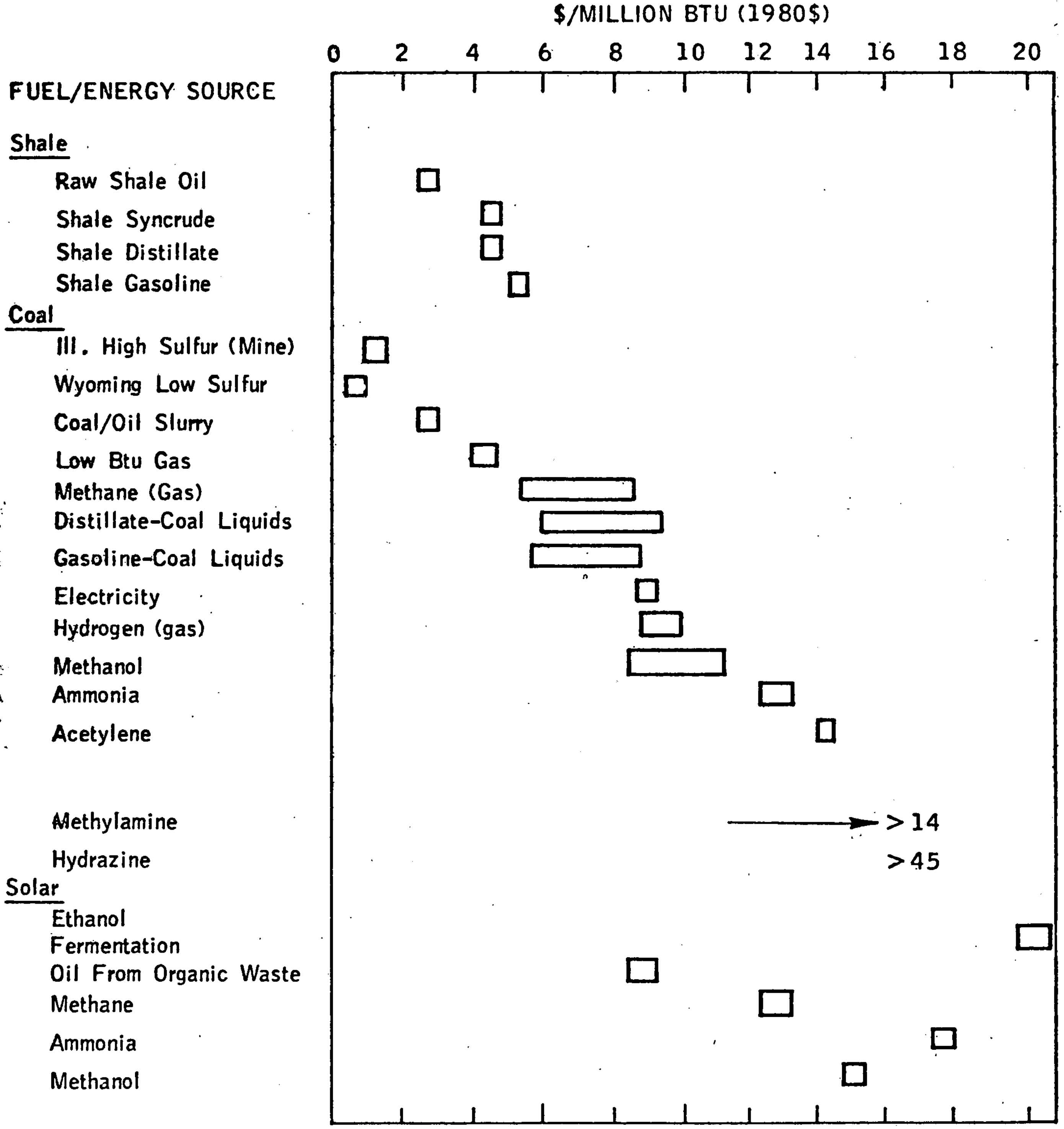
## COST OF ALTERNATE FUELS

| <10 $/MBTU | | 10-20 $/MBTU | | >20 $/MBTU | |
|---|---|---|---|---|---|
| Coal | 0.9 -1.6 | | | | |
| Raw shale oil slurry | 2.50-3.0 | | | Methanol by Pyrolysis of Solid waste | 20.75 |
| Coal-in-oil slurry | 2.55+ | Methanol from coal | 6.65-11.15 | | |
| Low BTU gas | 3.65-4.25 | | | | |
| Shale syncrude | 4.20-4.40 | | | | |
| Shale distillate | 4.20-4.40 | Methane from sewage algae | 12.50 | Ethanol by fermentation | 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 electrolysis | 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 3-2

COST OF ALTERNATE FUELS BY RESOURCE BASE



Also, this information is examined by fuel produced. Costs on this basis are presented in Table 3-4. 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.

### 3.2.2 Transportation, Distribution and Storage Cost of Alternate Fuels (Vol. IIIB - Section 7)

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 costs 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.

The transportation costs for the different alternate fuels and for various modes of transmission (pipeline, rail, barge, truck) have been 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 assumed, 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 the Appendix to permit adjustments to a different basis as to thruput.

The total delivered cost of the various alternate fuels are shown in Figure 3-3, with the details given in Table 3-5. 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/ M BTU which accounts for some of the numbers being slightly different from that number shown in other sections. Several interesting facts are apparent from Figure 3-3 and from the standpoint of the transportation and distribution costs.

- Transportation costs can be a significant cost in using coal as a fuel directly depending on whether eastern or western coal is used.
- 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 10-25% of the total delivered cost.

## Table 3-4
## Alternate Fuels Cost

| | Cost $/MBTU (1980$) |
|---|---|
| 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 3-4 (Cont.)

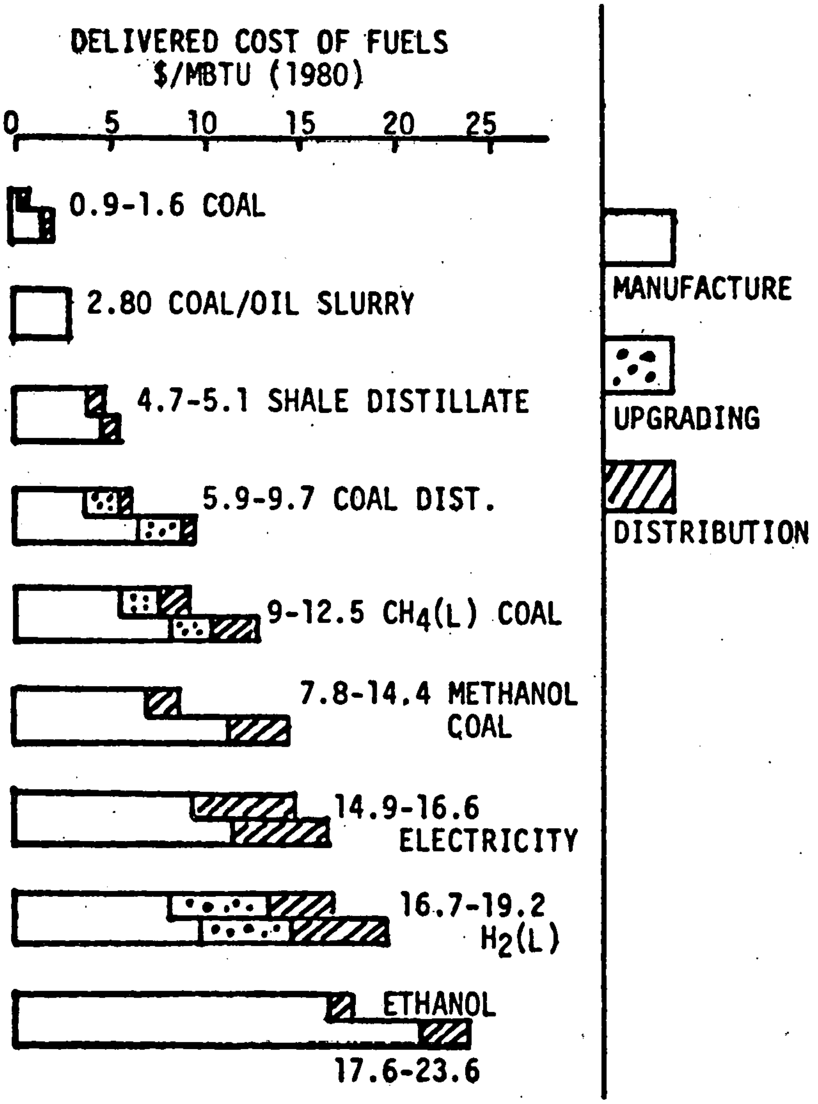
| | Cost, \$/MBTU (1980\$) |
|---|---|
| Oil from Organic Wastes(4) | 8.60 |
| Acetylene(8) | 14.00 |
| Methylamine(9) | > 14.00 |
| Hydrazine(9) | > 45 |
| Low BTU gas(10) | 4.25 |
| | ¢/kwh (1980\$) |
| Electricity | |
| o Coal(11)/Nuclear(12) | 3.00 |
| o Solar(13) | 10.90 |

**Notes: For Table 3-4**

(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

FIGURE 3-3

Total Delivered Cost of Alternate Fuels



## TABLE 3-5

## SUMMARY OF TOTAL DELIVERED COST OF ALTERNATE FUELS

$/ M BTU (1980 Cost)

| Fuel | Feedstock or Raw Material | Manufacturing Cost | Upgrading Costs | Fuel Transportation and Distribution | Total Cost | Transportation/ Distribution--% of Total |
|---|---|---|---|---|---|---|
| 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) | 3.80 | -- |
| Coal Liquids | 1.20-1.70 | 2.60-4.60 | 1.60-2.70 | 0.50-0.65 | 5.90-9.90 | 7-8 |
| Shale Oil Liquids | 2.50 | 1.70-1.90 | 0.00(7) | 0.50-0.70 | 4.70-5.10 | 11-14 |
| Methanol | 1.70-2.15 | 5.00-9.05 | -- | 1.10-3.20 | 7.80-14.40 | 14-22 |
| Ethanol | 9.00-13.50 | 7.70(5) | -- | 0.85-2.40 | 17.55-23.60 | 56-10 |
| Hydrogen | 1.70-1.80(4) | 6.20-7.90 | 4.90(6) | 3.80-4.80 | 16.10-18.90 | 23-25 |
| Methane | 1.90-2.70(4) | 4.20-6.05 | 2.00(6) | 1.6-1.8 | 9.70-12.55 | 13-19 |
| Ammonia | 2.20-2.30(4) | 10.10-10.60 | -- | 3.80-4.20 | 16.10-17.10 | 24-25 |
| Acetylene | 1.85(4) | 12.15 | -- | >4.60 | >18.65 | ~25 |
| Hydrazine | >37 | ? | -- | >3.25 | >>40 | |
| Electricity | 3.4 | 6.20 | -- | 5.3 | 14.9 | 36 |

---

(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.

- The transmission and distribution costs for electricity represent around 35% of the total cost for large commercial users.

Included in the technical detail section is a chart showing the flow of the raw material from the resource source to the final product in the customers tankage. The total production, transportation, and distribution system for coal liquids is shown in Figure 3-4, to illustrate the type of information that is available in the Appendix Volume IIIB.

### 3.2.3 Energy Efficiency in Producing and Transporting Alternate Fuels (Vol. IIIC - Section 10)

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 basic resource to the point of manufacture and the final product 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 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.

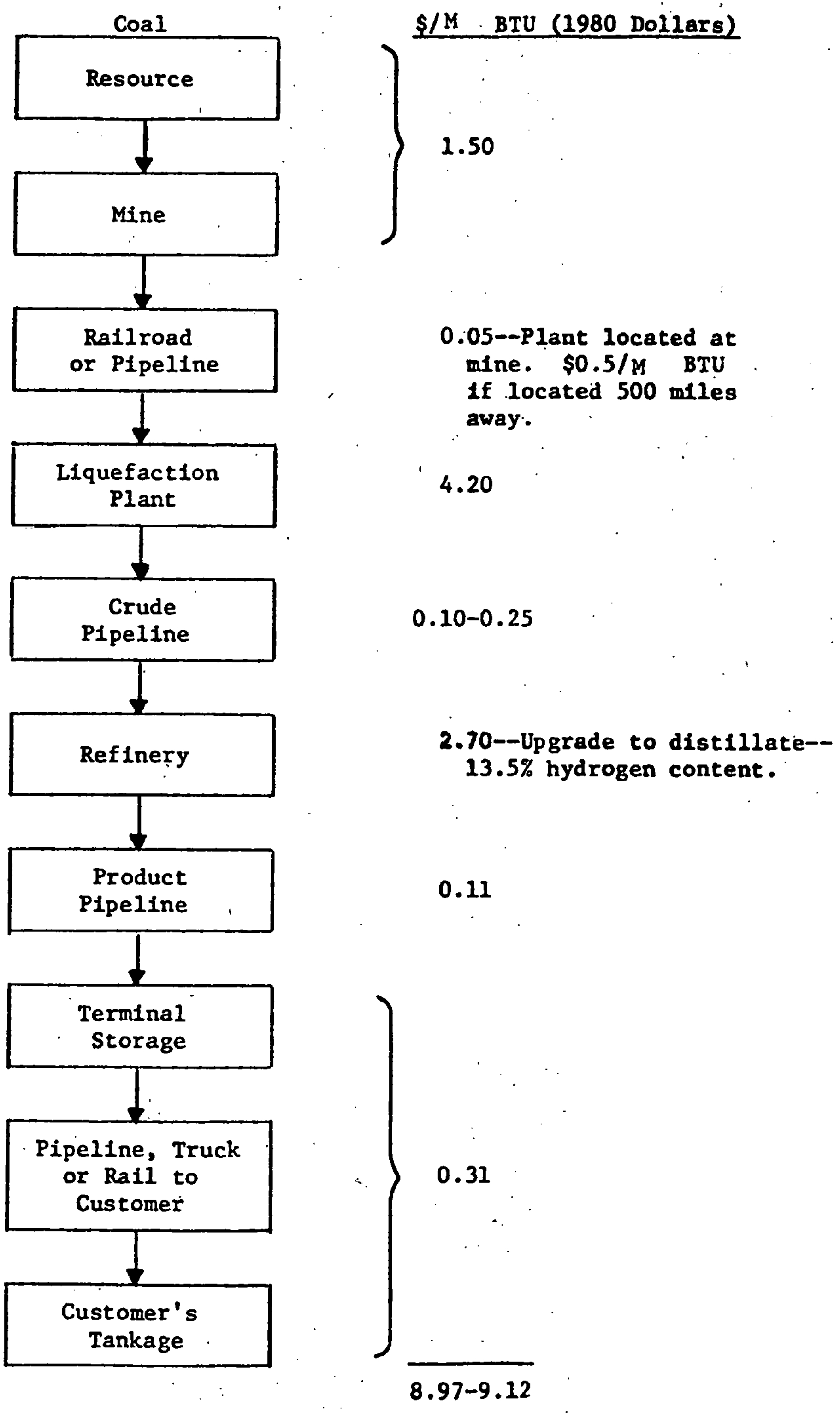
#### 3.2.3.1 Thermal Efficiency of Processes to Manufacture the Fuels

The thermal efficiencies of the various processes used to manufacture alternate fuels are summarized in Table 3-6 for the non-renewable based fuels and in Table 3-7 for the biomass based fuels. Two efficiencies are shown in Table 3-6; an efficiency which accounts for only the liquid transportation fuel ($\varepsilon_1$), and the overall thermal efficiency ($\varepsilon_2$). The $\varepsilon_1$ efficiency is defined as the ratio of the BTU output of the primary fuel/BTU input of the total resource. The $\varepsilon_2$ efficiency takes into account the heating value of the total product, and is the ratio of the BTU output of the total combustible product/BTU input of total resource. Figure 3-4 illustrates the way the two efficiencies would be calculated for a process producing methanol from coal. The $\varepsilon_2$ efficiency is the one normally reported in the literature, but the $\varepsilon_1$ 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 raw materials.

FIGURE 3-4

Coal Liquids Production, Transportation and Distribution System



## TABLE 3-6

## SUMMARY OF PROCESSING THERMAL EFFICIENCIES - NON-RENEWABLE BASED FUELS

| Fuel | $\varepsilon_1$-% (Liquid Fuel Only) | $\varepsilon_2$-% (Total Thermal Efficiency) |
|---|---|---|
| Coal/Oil Slurry | 97-98.5 | 97-98.5 |
| Shale Oil - Upgraded | 65 | 64-72 |
| Coal Based Fuels | | |
| - 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 |
| Other Energy Carriers | | |
| - Hydrogen - Electrolysis | | 30-33 |
| - Electricity - Coal (conventional) | | 35-37 |
| (new technology) | | 55-68 |
| - Nuclear | | 32 |

---

(g) = gas

## TABLE 3-7

## SUMMARY OF PROCESSING THERMAL EFFICIENCIES - BIOMASS BASED FUELS

| Fuel | Product Energy/ Process Energy Input (1) | $\varepsilon_2$ Thermal Efficiency |
|---|---|---|
| **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 |

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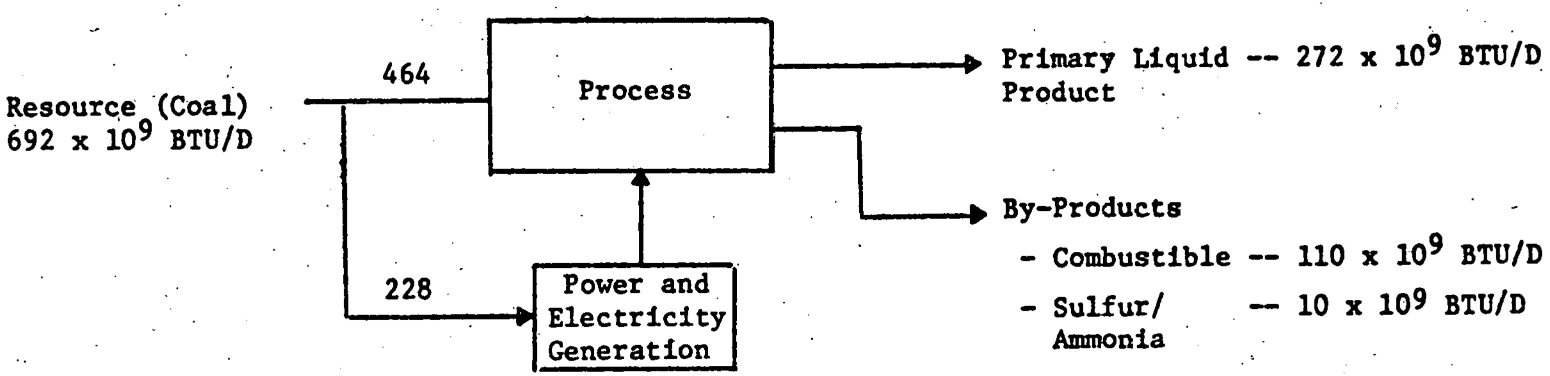
(1) See Appendix Volume IIIC - Section 10 for definition.

## FIGURE 3-4

## Example of Energy Efficiency Calculation



$$\varepsilon_1 = \frac{\text{BTU Output of Primary Fuel}}{\text{BTU Input of Total Resource}} = \frac{272}{692} = 0.393 \text{ or } 39.3\%$$

$$\varepsilon_2 = \frac{\text{BTU Output of Total Combustible Product}}{\text{BTU Input of Total Resource}} = \frac{382}{692} = 0.552 \text{ or } 55.2\%$$

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/pound, which then allows the thermal efficiency of the process to be calculated.

The $\varepsilon_2$ thermal efficiencies are illustrated in Figure 3-5 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 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 3-5, as a separate item, is the efficiency for upgrading of coal liquids, liquefaction of hydrogen, and liquefaction of methane. These efficiencies must be considered in conjunction with the basic process efficiency to arrive at an "overall" efficiency.

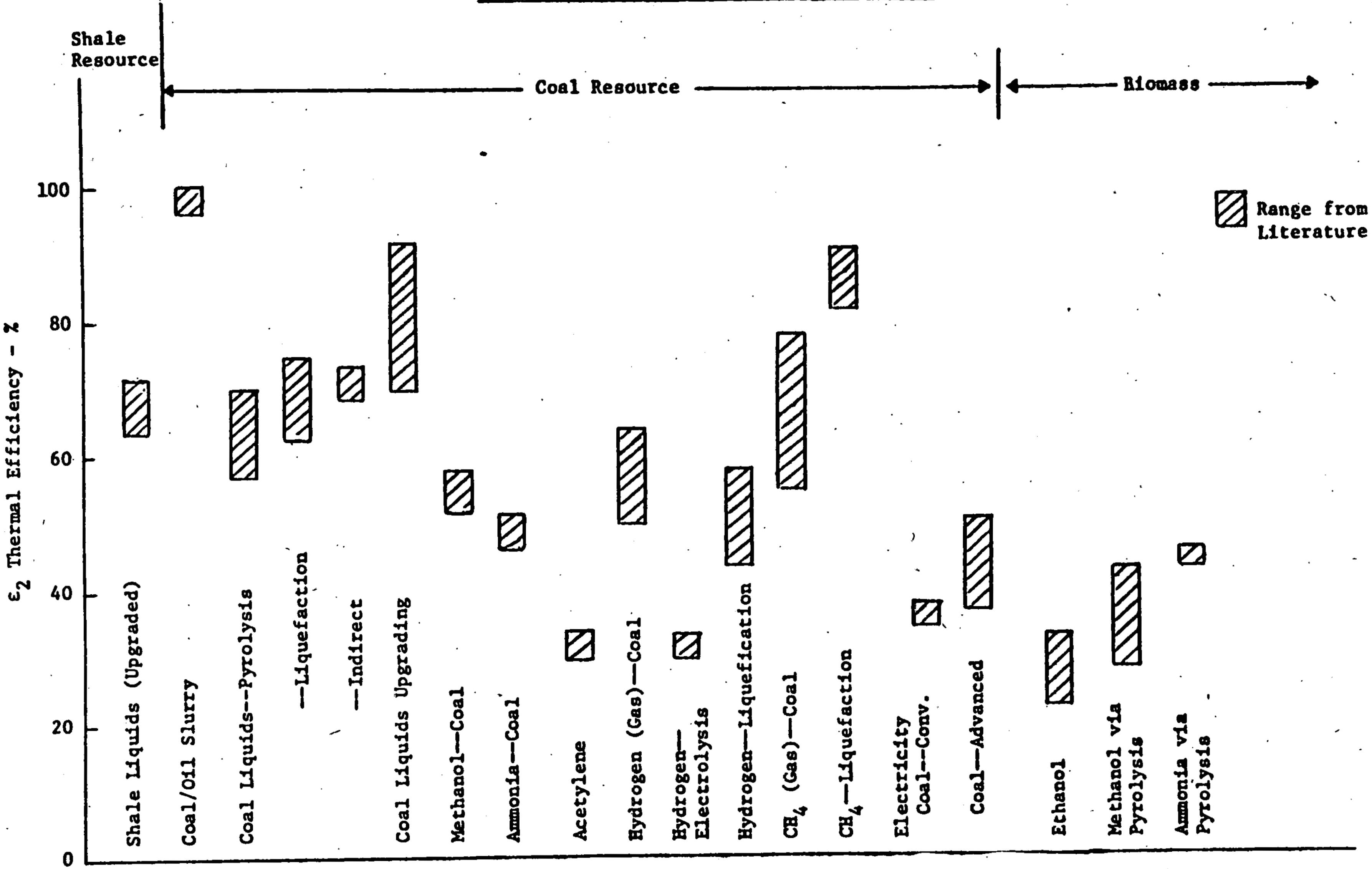
Several comments on Figure 3-5:

- In the coal liquids area, the liquefaction route was selected as representative. The pyrolysis and indirect methods have lower $\varepsilon_1$ 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 3-6 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 1.88x million BTU of coal to produce a million BTU of liquid transportation fuel. Methanol and ammonia require 2 and 2.15 million BTU of coal to produce a million BTU of liquid transportation fuel, respectively. Electricity, liquid hydrogen and acetylene require the largest amount of coal, of the alternate fuels considered.

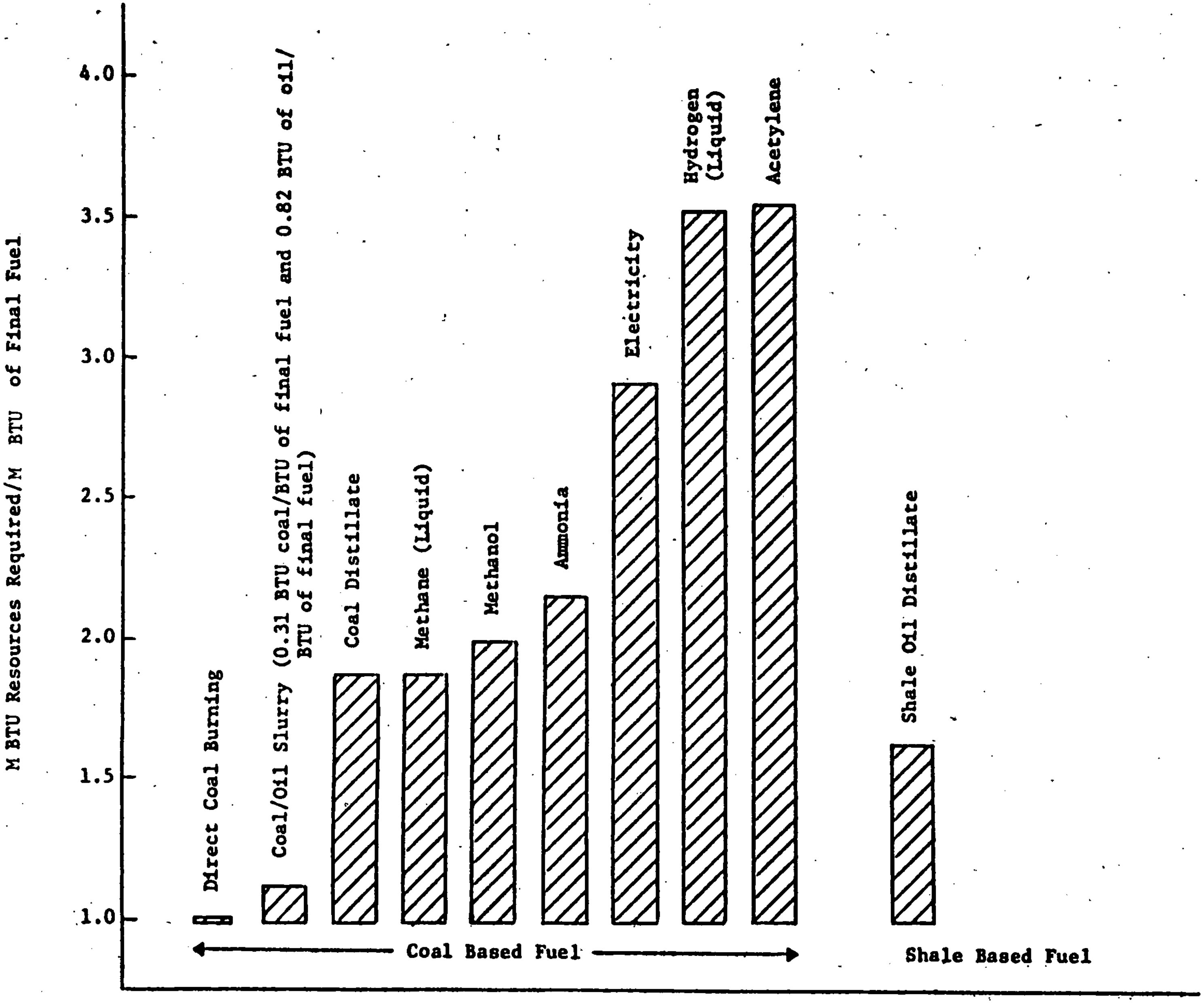
## FIGURE 3-5

## THERMAL EFFICIENCIES OF VARIOUS PROCESSES USED TO MANUFACTURE ALTERNATIVE FUELS



## FIGURE 3-6

## BASIC RESOURCE REQUIREMENTS FOR SEVERAL ALTERNATE FUELS



To produce a million BTU of distillate from shale oil required 1.63 M 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.

### 3.2.3.2 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 3-8 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.

### 3.2.3.3 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 3-7 shows the total resources required to produce distillate from coal. Two types of energy are represented--the amount of coal 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 3-7, it takes 1.82 million BTU of coal to provide a a million BTU of energy in the form of distillate in the customers' tanks. In addition, 0.06 million 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 3-7.

Similar charts for the coal-based alternate fuels are given in the Appendix (Volume IIIC). Table 3-9 summarizes the information from these figures. As shown in Table 3-9, 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 million BTU of coal to provide a million BTU of energy to the customer. Liquid hydrogen and acetylene require the most resource to provide a million BTU of fuel.

## TABLE 3-8

### Summary of Transportation Energy Requirements for Alternative Fuels

| Fuel | Primary Eff. | Fuel/Electricity Required to Move the Product BTU/$10^6$ BTU Output |
|---|---|---|
| **Coal** | | |
| - Unit train | 1.0 | 20 L(1) (Eastern Coal)*<br>31 L (Western Coal)* |
| - Slurry pipeline | 1.0 | 48 L (Western Coal) |
| - Barge | 1.0 | 13 L (Eastern Coal) |
| - Train | 1.0 | 30 L (Eastern Coal)<br>45 L (Western Coal) |
| - Train | 1.0 | 20 L |
| Crude Pipeline | 1.0 | 48 L*<br>16XL (36"ϕ-High Flow Rate)<br>46XL (18"ϕ-High Flow Rate) |
| Petroleum Pipeline (also coal or shale liquids) | 1.0 | 15 L*<br>4 L<br>4 L (25"ϕ-High Flow)<br>23 L (12"ϕ-High Flow) |
| Methanol Pipeline | 1 | 30 L* |
| Methane | $1-3.6 \times 10^{-5}$L* | - |
| Hydrogen (gas) | $1-5.2 \times 10^{-5}$L* | - |
| Electricity transmission and distribution | 0.91* | - |
| | 0.92 | - |

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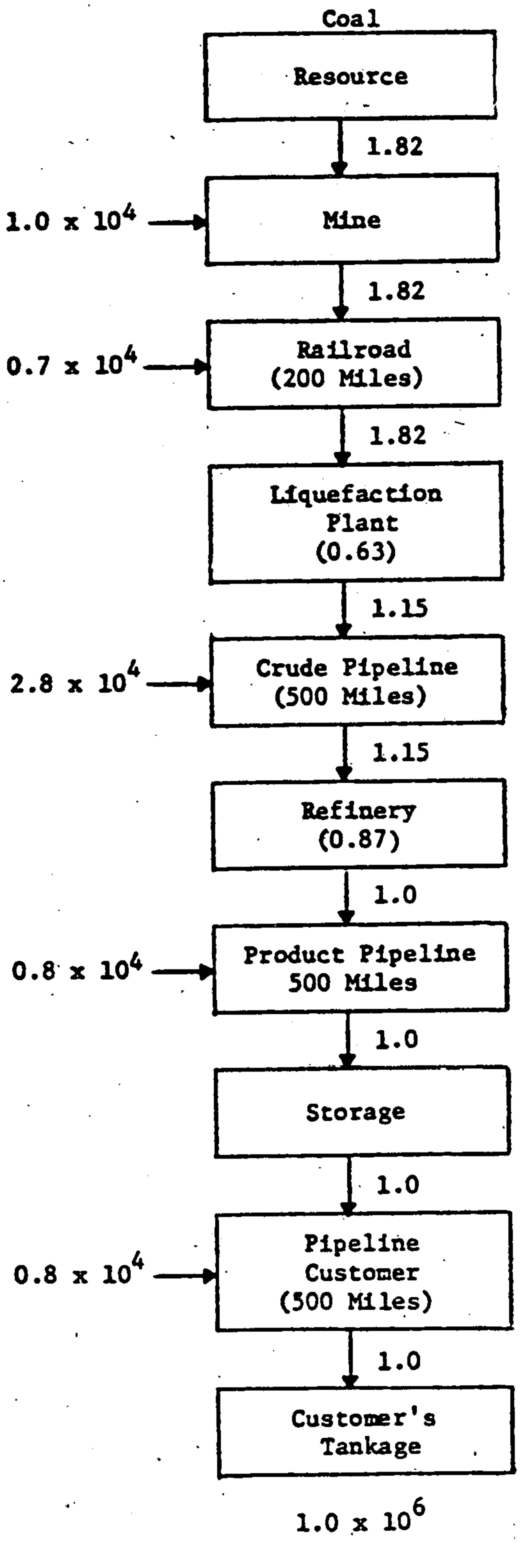
* Value used in this study.
L = transport distance in miles.

(1) 20 times the transport distance in miles.

FIGURE 3-7

COAL LIQUIDS PRODUCTION, TRANSPORTATION AND DISTRIBUTION SYSTEM



Total Resources - $10^6$ BTU/$10^6$ BTU Fuel

Coal —1.82
Ancillary—0.06
1.88

## TABLE 3-9

## Summary of Total Resources Requirements

| | BTU of Resource/BTU of Final Product | | |
|---|---|---|---|
| | Direct Requirement | Ancillary Fuel/Electricity | Total |
| **Coal** | | | |
| For Direct Burning | 1.0 | .016-.036 | 1.02-1.04 |
| Coal/Oil Slurry | 0.31-Coal<br>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 |
| **Shale** | | | |
| Shale Distillate | 1.59 | .04 | 1.63 |

### 3.2.4 Environmental Impact in Production (Vol. IIIC - Section 8)

One of the factors to be considered in the preliminary screening of the various alternate fuels is the environmental impact during production. Pollutants from a process are a function of a number of variables and no hard numbers can be assigned to any process. Some of the major factors determining qualities of effluents are plant design, location, raw materials and the means used to provide utilities.

An order of magnitude guide to the emissions from the production of various fuels is given in Table 3-10, and a breakdown of the air pollutants are given in Table 3-11. Values given in the tables are calculated based on values given in the literature. The quantity of effluents are based on BTU of fuel output. In general, a particular fuel or process should not be chosen on the basis of the effluents resulting from an arbitrary design, since it is possible to modify the emissions by adding control devices. However, the information in Table 3-11 was used to develop the rankings that will be described later.

### 3.2.5 Physical and Chemical Properties of Alternate Fuels (Volume IIIA - Section 3)

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, of 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 the Appendix Volume (IIIA-Section 3). It is evident that the properties of the fuel have an impact on many important criteria. The interrelationships are summarized in Table 3-12, which serves as the general basis for categorizing the property data collected in this study. Typical values for petroleum fuels are included 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

## TABLE 3-10

## Environmental Impact in Production ≠

| Fuel | Air*<br>lbs/ M BTU | Water<br>lbs/ M BTU | Solids<br>lbs/ M BTU |
|---|---|---|---|
| Coal** | 0-9x10$^{-3}$ (1) | 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$^{-3}$ | 0 (8-5) (8-6) | 0.06-160 (8-5) (8-6) |
| Syncrude | 0.2 -0.4 | 0-5x10$^{-4}$ | 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 -0.6 | 0-0.16 | 13 (8-2) (8-6) -19 (8-2) |
| Electricity from Coal | 1.9 | 0**** | 22-67 (8-8) |

---

* See Table 3-11.

** Does not include coal lost in cleaning or left in mine.

*** Prorated from Methanol.

≠ Values are pounds of emissions/10$^6$ 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 $H_2$.

●● Prorated from Coal Liquids.

**** Water assumed to be ponded.

(1) References are listed in the Appendix Volume IIIC - Section 8.

## TABLE 3-11

## Details of Air Pollutants

| Fuel | $SO_x$ | $NO_x$ | Particulates | Hydrocarbons | CO | Other |
|---|---|---|---|---|---|---|
| Coal(8-6)(1) | $3.6x10^{-4}$ | $5x10^{-3}$ | $1.7x10^{-4}$ | $5x10^{-5}$ | $3x10^{-3}$ | $8x10^{-5}$ |
| Coal Liquids(8-6) | 0.04 | 0.23 | $9x10^{-3}$ | $9x10^{-4}$ | $7x10^{-3}$ | $8x10^{-4}$ |
| Raw Shale(8-6) | $9x10^{-5}$ | $1x10^{-3}$ | $4x10^{-5}$ | $1x10^{-4}$ | $7x10^{-4}$ | $1x10^{-5}$ |
| Shale Syncrude(8-6) | 0.11 | 0.04 | $5x10^{-4}$ | 0.04 | $4x10^{-5}$ | $3x10^{-4}$ |
| Methanol From Coal(8-1) | 0.05 | 0.08 | $7x10^{-3}$ | $1.3x10^{-3}$ | - | - |
| Hydrogen From Coal | 0.04 | 0.07 | $6x10^{-3}$ | $1x10^{-3}$ | - | - |
| Ammonia From Coal | 0.06 | 0.1 | $8x10^{-3}$ | $1.4x10^{-3}$ | - | - |
| Methane(8-6) From Coal | 0.09 | 0.4 | 0.05 | $6x10^{-3}$ | 0.02 | $1x10^{-3}$ |
| Electricity(8-8)(8-9) From Coal | 1.2 | 0.7 | 0.01 | 0.01 | 0.04 | $2x10^{-4}$ |

(1) References are listed in Appendix Volume IIIC - Section 8

## TABLE 3-12

## Relation of Fuel Properties and Functions

| | Distribution | Storage (Bulk and on Vehicle) | Environmental Impact | Safety | Compatibility with Pet. Fuels | Prime Mover Performance | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Diesel | Gas Turbine | S.I. Internal Comb. | Fuel Cell | Stirling | Steam Boiler |
| 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 3-12 (Continued)

|  |  |  |  |  |  | Prime Mover Performance |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|---|---|
|  | Distribution | Storage (Bulk and on Vehicle) | Environmental Impact | Safety | Compatibility with Pet. Fuels | Diesel | Gas Turbine | S.I. Internal Comb. | Fuel Cell | Stirling | Steam Boiler |
| 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

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 Appendix Vol. IIIA-Section 3 as discrete studies on specific syncrudes by specific refining operations.

### 3.2.5.1 Combustion Properties

A number of significant observations can be made regarding the combustion properties of the fuels shown in Table 3-13. The boxes around some of the values in Table 3-13 indicate the areas that are discussed in the following statements.

- The low boiling points of hydrogen, methane, ammonia, methylamine and acetylene indicate that special equipment will be required to store and handle these materials. In addition aceytlene is unstable and would require special handling. Storage could be either as 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. Seasonal storage would be costly.

- 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. $NO_x$ emission standards may place a limit on operating at stoichiometric conditions.

- 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

## TABLE 3-13

## Fuel Characteristics Related to Combustion Behavior

| | Heat of Combustion (Net) | | Heat of Vap-BTU/lb | Volatility (Boiling Pt)-°F | | | | Vapor Pressure |
|---|---|---|---|---|---|---|---|---|
| Fuel | BTU/lb | BTU/Gal | @ Normal Boil Pt | Initial | 50% | 90% | Final | @ 100°F psi |
| 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 3-13 (Continued)

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

---

(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.

be demonstrated with ammonia and methanol, in view of the uncertainty in translating experience based on high octane hydrocarbon fuels to widely different compounds.

- 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, 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.

- The Cetane Number of all the fuels in Table 3-13, 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. Unfortunately, the wide flammability limits adds to the hazard of using hydrogen as a fuel.

### 3.2.5.2 Vehicular Storage Requirements of Fuels

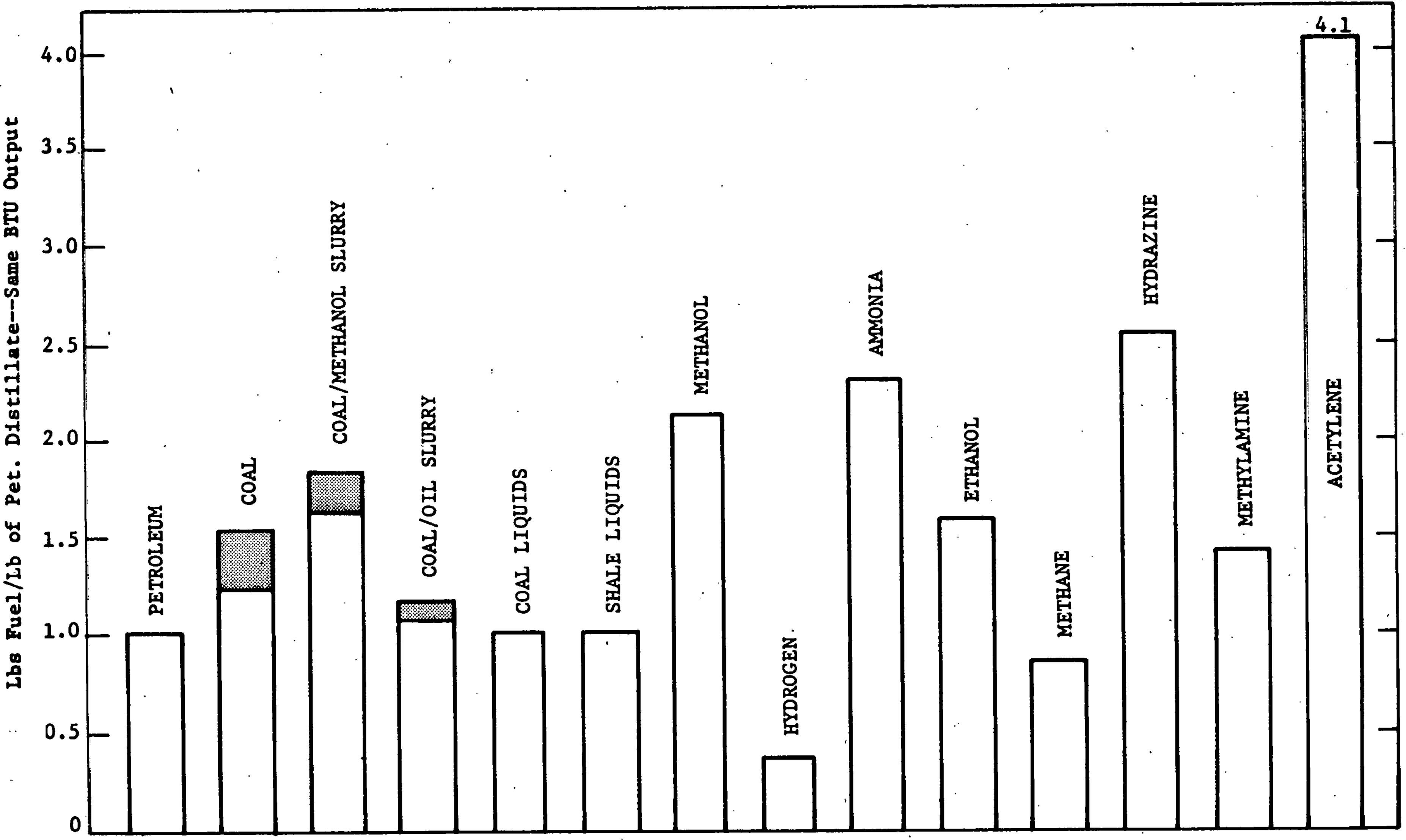
The low boiling points of ammonia, methane, hydrogen, and acetylene present a problem with regard to the storage of these fuels. For acetylene it would be necessary to store the acetylene in acetone or use calcium carbide to directly generate acetylene. The magnitudes of the storage problem for each of the fuels being considered are compared to petroleum distillate in Figure 3-8, on a weight basis, and Figure 3-9 on a volumetric basis. Detailed data are given in Table 3-14. The fuels that show a 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 the 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. 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.

## FIGURE 3-8

### Fuel Storage Requirements

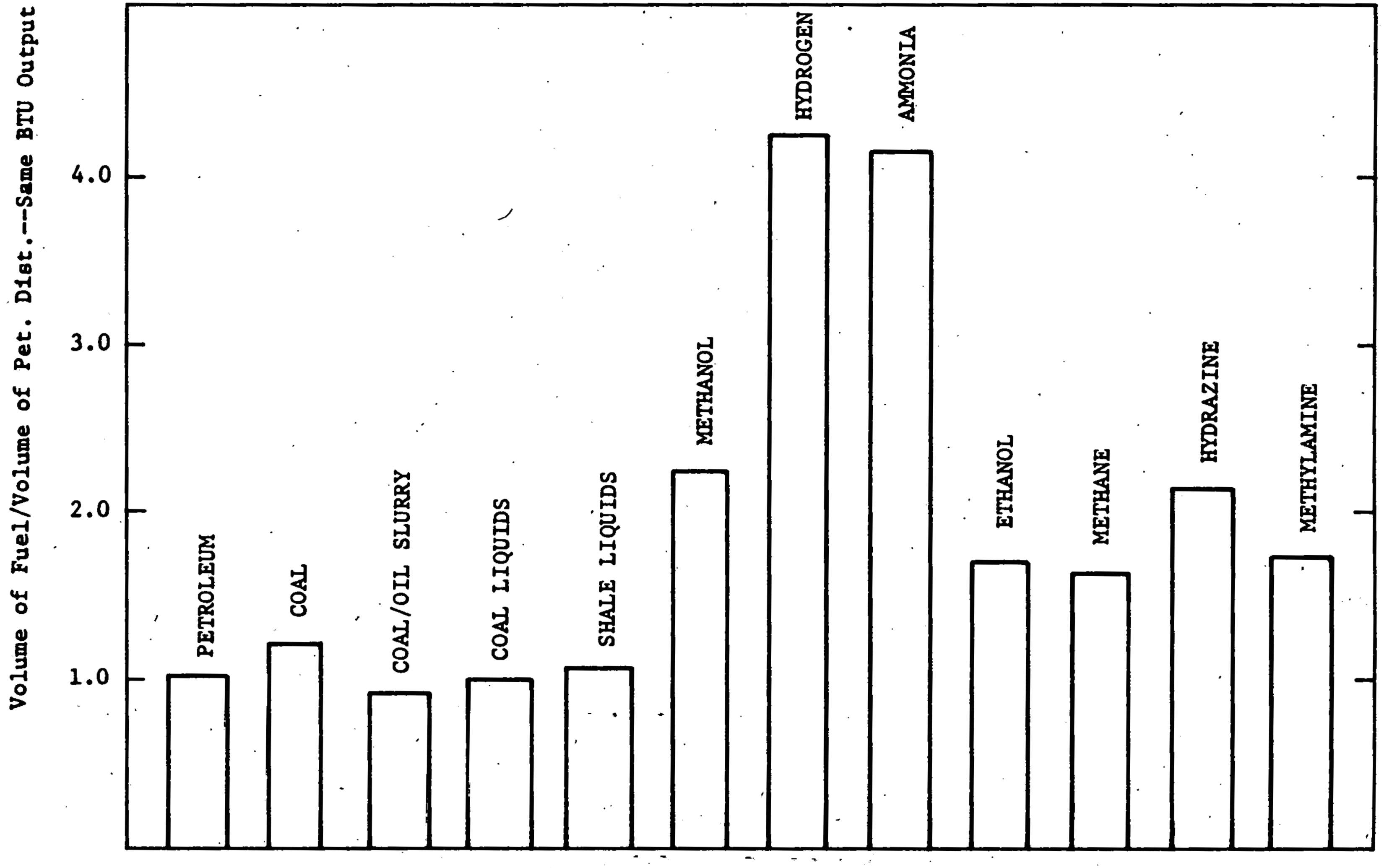
### - Weight -



## FIGURE 3-9

## Fuel Storage Requirements

- Volume -



## TABLE 3-14

## 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.

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.

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.

### 3.2.5.3 Bulk Handling and Storage of Fuels

Table 3-15 lists the characteristics related to the handling and bulk storage of the fuels. The boxes around some of the values indicate the areas that are discussed below:

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). Raw shale and syncrude also have a high freeze point and additives or processing will be required to reduce the pour point.

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.

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. Ammonia and hydrazine are apparently the most corrosive fuels considered. 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,

Table 3-15

## Convenience in Handling and Storing Various Alternate Fuels

| Fuel | 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 |
|---|---|---|---|---|---|---|---|
| Petroleum | | | | | | | |
| - Gasoline | (-40) | -30 | Nil | | NP(2) | NP(2) | NP(2) |
| - Broadcut | (-30) | -30 | Nil | | NP(2) | NP(2) | NP(2) |
| Coal | -- | | Nil | | | | |
| Coal/Methanol Slurry | | (50)(1) | | | | | |
| Coal/Oil Slurry | | (>130) | Nil | | | | |
| Coal Liquids | | | | | | | |
| - Jet Fuel (JP-4) | -90 | | Nil | | | | NP(2) |
| - Diesel | (-20—+5) | | Nil | | | | NP(2) |
| - Fuel Oil | | | Nil | | | | NP(2) |
| Shale Oil Liquids | | | | | | | |
| - Raw | 75 | | Nil | | | | NP(2) |
| - Syncrude | 50 | | Nil | | | | NP(2) |
| Methanol | -142 | 52(1) | Infinite | Infinite | | | |
| Hydrogen | -435 | -- | | | NP | NP | |
| Ammonia | -108 | -- | 33.1 | | NP | | Corrodes Copper, Brass, & Zinc |
| Oxygenated Compound | | | | | | | |
| - Ethanol | -179 | 65(1) | Infinite | Infinite | | | |
| - Higher Alcohols | (-170) | >65(1) | | | | | |
| Methane | -296 | -- | | | NP | NP | |
| Hydrazine | 35.6 | 126(1) | Infinite | Infinite | | NP | Corrosive to Certain Metals |
| Methylamine | -136 | | Very | | | | |
| Acetylene | -115 | | | | NP | | |
| Vegetable Oil (Cotton Seed) | 26 | 275 | | | | | |

---

(1) Open cup.
(2) Can be controlled by careful refining and use of additives.

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.

6. Hydrogen can cause metal embrittlement at elevated pressures even at ambient temperatures. This must be considered in designing systems for distributing and storing hydrogen.

### 3.2.5.4 Engine Maintenance

The major fuel properties that relate to engine maintenance requirements are the ash content, the amount of sodium and vanadium in the fuels, the sulfur content and the sludge forming tendency. Detailed data are given in Appendix IIIA. The fly ash content of the coal will be particularly troublesome in many applications.

The sludge tendency 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-time 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., Nitrogen containing high boiling components) 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.

### 3.2.5.5 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. Table 3-16 summarizes the toxicity hazards for some of the fuels. Detailed discussion on each of the fuels is given in the Appendix.

### 3.2.5.6 Safety

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

The pertinent properties of the possible alternative fuels are listed in Table 3-17. 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:

## TABLE 3-16

## Toxicity Hazards

| | Oral Ingestion | Skin Penetration | Inhalation | Eye, Skin, Nose Contact | Prolonged Exposure PPM |
|---|---|---|---|---|---|
| Gasoline--Petroleum/Coal/ or Shale | Low--Apart from Aspiration | Low | High | Moderate | 500 |
| Distillate--Petroleum/Coal/ or Shale | Low--Apart from Aspiration | Low | High | Moderate | 500 |
| Methanol | Very High | Moderate | Low | Slight to Moderate | 200 |
| Ethanol | Moderate | Low | Low | Slight to Moderate | 1000 |
| Methane | | | | | Asphyxiant |
| Hydrogen | | | | | Asphyxiant |
| Ammonia | Unlikely | Low | Moderate | Variable | 100 |
| Hydrazine | | | | | 1 |
| Methylamine | | | | | 10 |
| Acetylene | | | | | Asphyxiant |

## TABLE 3-17

## Fuel Performance Criteria--Safety(c)

| Fuel | Volatility Initial Boiling Point - °F | Flammability Limits - Vol % Upper | Flammability Limits - Vol % Lower | 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) |
|---|---|---|---|---|---|---|---|---|---|
| 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 ft³ | -- | -- | 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 3-17

(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.

- The lower flammability limits of methanol and ethanol are 6 vol. % and 3.5 vol. %, respectively, versus about 1 vol. % for petroleum liquids, but the flammability range is wider. 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.

### 3.2.6 Fuel Logistics
### (Vol. IIIC - Section 12)

The logistics of alternative energy sources are considered from three different aspects: (1) compatibility of alternative energy resources with present fuels and with the current fuel distribution system; (2) international and military considerations, and (3) resource availability.

Each factor 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.

### 3.2.6.1 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.

Also considered under compatibility with present fuels is the relationship between highway and non-highway transportation systems. From a fuel standpoint there may be a greater similarity between individual highway systems and non-highway subsystems than there is among the different non-highway modes. In fact, one needs to consider the overall energy supply system, since there are interactions between the transportation and non-transportation areas.

An overall rating of the various fuels from a compatibility standpoint is given in Table 3-19.

### 3.2.6.2 International and Military Considerations

International considerations may be divided into (a) fuels and (b) equipment. 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.

### 3.2.6.3 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. One way to visualize this is to consider that there will be a "pool" of fuels and energy supplies, derived from all resources. This "pool" must be divided among all of the various demands for fuels and energy and if the sum of the various demands exceeds the supplies available, then end-uses will be constrained. 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.

#### 3.2.6.3.1 Primary Energy Resources

The principal primary energy resources, except for petroleum (crude oil and natural gas) are listed in the first column of Table 3-18. The next column provides a qualitative characterization of the size of the resource base of each of the primary resources. These characterizations are defined as follows:

- 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.*
- 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.

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*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.

## TABLE 3-18

## 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<br>methanol<br>[ethanol]<br>hydrazine<br>methylamine | hydrogen<br>methane<br>ammonia<br>acetylene<br>slurries |
| Oil Shale(5),(6) | very large | negligible | high | major | raw shale oil<br>shale syncrude$^{\o}$ | |
| Peat(7) | very large | negligible | small | major | peat liquids | methane |
| Biomass (8),(9),(10),(11),(12),(13),(14) | large | medium | medium | major | methanol<br>ethanol<br>other alcohols | methane<br>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 |

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*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.

ø further processing of shale syncrude would generate a range of petroleum-type transportation fuels.

( ) denotes references, which are listed in Vol. - Section 12.

- "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 3-18, 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 3-18 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.

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*In 1978, it is anticipated that nuclear energy and hydro power will each supply about 4% of U.S. primary energy demand.

### 3.2.6.3.2 Documentation of Size of Primary Resource Base

The purpose of the following discussion is to support the characterizations of the resource base in Table 3-18:

- 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 the Appendix Volume IIIC, 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.

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*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.

- 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 3-18, only the portion of solar energy used to generate electricity or heat is considered as "solar".

- nuclear: in the context of Table 3-18 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.

### 3.2.6.3.3 Logistics of the Principal Primary Energy Resources

There are significant logistical differences among the various primary energy resources. Some of the characteristics of these differences are described below. 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.

### 3.2.6.3.4 Alternate Fuel Availability

The availability of the principal primary energy resources and the various fuels derived from these resources are shown in Figure 3-10. As shown in Figure 3-10, several of the fuels have an asterisk in the time bar--indicating the judgment that although that specific fuel may be available in a given time frame, it is expected that it will be utilized in some other end-use rather than as a non-highway transportation fuel.

### 3.2.6.4 Fuel Logistics Criteria

All three factors; availability, compatibility with the current system and international considerations, are summarized in Table 3-19. The final column is a preliminary indication of how the various fuels may be

## Alternate Fuel Availability

FIGURE 3-10

| Resource | Availability → Fuel | Now or By 1980 | By 1990 | By 2000 | After 2000 |
|---|---|---|---|---|---|
| Coal | | | | | |
| | Raw Liquids | | *---- | —— | —— |
| | Upgraded Liquids | | *---- | —— | —— |
| | Methanol | | ---- | —— | —— |
| | Hydrazine | | | | Uncertain |
| | Methylamine | | | | Uncertain |
| | Hydrogen | | *---- | *—— | —— |
| | Methane | | ---- | —— | —— |
| | Ammonia | | *---- | *—— | —— |
| | Acetylene | | | | Uncertain |
| | Oil Slurry | ---- | —— | —— | —— |
| | Methanol Slurry | | ---- | —— | —— |
| Oil Shale | Raw Shale Oil | | —— | —— | —— |
| | Syncrude | | —— | —— | —— |
| Biomass | Methanol | | *---- | *—— | —— |
| | Ethanol | —— | —— | —— | —— |
| | Methane | *—— | —— | —— | —— |
| | Other Alcohols | insignificant availability expected | | | |
| | Vegetable Oils | insignificant availability expected | | | |
| | Oil from Organic Waste | if available, would be used as blending agent | | | |

- Notes: ---- possible
  —— probable
  * probable utilization for purposes other than NHT fuels.

## TABLE 3-19

## Fuel Logistics Criteria

| Resource | Derivative Fuel | Availability[ø] | Compatibility with Current | | International Considerations |
|---|---|---|---|---|---|
| | | | Fuels | System | |
| Coal | | 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 | - | - | - |

ø ratings as follows:

1 = now or by 1980
2 = by 1990
3 = by 2000
4 = after 2000

A = possible
B = probable
U = unlikely or highly uncertain
* = probable utilization for purposes other than NHT fuels

impacted by international considerations. The rating "variable" is based on the premise 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.

## 3.3 Prime Movers

The basic background information on the different prime movers being considered in this study was given in Section 3.1.1. In these three sections, the efficiency of the various types of engines are covered, as well as the potential environmental effects from using the various fuels in the different type of power plants. The last section covers the interrelationships between fuels and prime movers.

### 3.3.1 Energy Efficiency in Use (Vol. IIIC - Section 11)

The general requirement for a heat engine is to compress a fluid (air, water, helium, etc.), add heat to this fluid at the highest possible temperature, and then release the exhaust at the lowest possible temperature. Thus, the efficiency of any engine is the fraction of chemical heat in the fuel, which after release by oxidation is converted to useful work at a shaft or in the case of aircraft to useful thrust. The thermal efficiency of a prime mover is much more a function of its design and operating conditions, than of the particular fuel that is used.

The efficiency of an engine is largely a function of its compression ratio, its tolerance to a high top working temperature and its ability to complete the combustion of its fuel while the working fluid is still under considerable compression. The thermal efficiency for four different types of prime movers, shown below, illustrates this, since each varies in compression ratio and inlet and outlet working fluid temperature.

| | Diesel | Otto | Gas Turbine | Steam Turbine |
|---|---|---|---|---|
| In | 3000°F + | 3000°F + | 2000°F | 1000°F |
| Out | 600°F | 1000°F | 900°F | 80°F |
| Comp. Ratio | 20 | 8-12 | 7 | 2000 psig - Vac. |
| % Eff. | 40 | 30 | 25 | 35 |

In this study all efficiencies are expressed as the percentage of the net heating value of the fuel which is converted to work.

### 3.3.1.1 Thermal Efficiency of Various Prime Movers

The list of prime movers in order of efficiency is as follows:

| Engine | % Efficiency |
|---|---|
| Fuel cell/electric motor | 50 - 60 |
| Gas turbine/combined cycle | 40+ |
| Diesel | 35 - 40* |
| Stirling | 30 - 40 |
| Free piston | 25 - 30 |
| Boiler/steam | 25 - 35* |
| Otto | 22 - 34* |
| Gas turbine | 25 - 32* |

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.

The probable efficiency for combinations of various fuels and prime movers have been listed in Table 3-20. 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 and coal/oil slurry to run in diesel engines, 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.

Overall, if a given fuel can be burned in a particular prime mover, the thermal efficiency of the prime mover will be about the same, for all fuels. There are a few exceptions to this generalization which is described in Section 3.3.1.4.

### 3.3.1.2 Advantages of Various Prime Movers

- Diesel Engines. From an efficiency standpoint 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 at part load. It is for this reason that the diesel has come to dominate railroad and marine propulsion.

## TABLE 3-20

| 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 | -- | -- | -- | -- | -- | -- | -- |
| 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 | 33-44 | 27-33 | -- | -- | -- | -- | -- | 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.

- Free Piston Engines. The free piston engine is a form of hybrid between the diesel and the gas turbine, which gives a 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 that it can burn anything from gasoline to bunker fuel oil.

- Gas Turbine. The efficiency of the gas turbine is not as high as some of the other engines, because in some instances efficiency has been traded to obtain low weight per unit of power (aircraft) and because of their low cost per horsepower and lack of cooling water requirement (pipeline pumping). The efficiency can be improved by the use of regenerators and combined cycles. In addition, increasing the turbine inlet temperature will improve efficiency. 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. There are indications that liquid hydrogen and alcohols could give higher efficiencies.

- Spark or Pilot Ignited Engines (Otto Cycle). 'In non-highway transportation, these engines are primarily used in small aircraft and boats and in certain pipeline applications. The upper limit on efficiency for this type of engine is about 34% and they require a fuel with a high octane number. There are some special advantages for hydrogen and alcohols with this type of engine.

- Externally Fired Engine (Steam Turbines, Stirling and Closed Cycle Gas Turbines). The efficiency of engines where the fuel is burned externally depends on three factors: (1) efficiency of the combustion equipment, (2) the operating temperature range of the working fluid, and (3) the efficiency of the turbine or engine. One feature of the externally fired engine is that they may be considered as omniverous, and only slightly affected, as far as efficiency goes, by the quality of fuel used.

- Fuel Cell/Electric Motor. The fuel cell/electric motor has the highest efficiency of the prime movers considered and the efficiency is maintained at all loads, and may even be better at part load than at full load. However, the fuel cells are much heavier than the internal combustion engine producing equal power.

#### 3.3.1.3 Fuel/Engine Incompatibilities

There are some fuels that do not have the physical properties to be compatible with a diesel engine. There are at least three levels of incompatibility: (1) the fuel may not ignite at a reasonable compression ratio; (2) the fuel may ignite, but with such a delay that the conversion of heat to work cannot be optimized and engine damage may result; and (3) the fuel may ignite but take so long to burn that its heat content is not released and there is unburned fuel in the exhaust gas. There are several modifications that can be made to overcome these problems. These include fumigation for the diesel engine, additive treatment, e.g. centane improver or double injection. After these modifications have been made and the fuel becomes usable, the thermal efficiency of the engine is close to that of the conventional engine running on more conventional fuels.

#### 3.3.1.4 Fuel Properties that Enhance Efficiency

There are certain fuels, mainly hydrogen and the alcohols, which have properties which permit modifications to conventional engines that will enhance their thermal efficiency. Thus, with hydrogen, since it has a wide range of flammability, it can be run in a spark ignited engine with a very lean mixture, resulting in improved efficiency. This improvement in efficiency is also due to the rapid combustion characteristic and the specific heat properties which improve the thermodynamic cycle. In addition, liquid hydrogen can act as a heat sink and allow higher inlet temperatures to a gas turbine, thus providing better thermal efficiency.

To a lesser extent the alcohols exhibit some of the special properties of hydrogen, i.e. ability to operate at leaner limits than gasoline and the ability to absorb heat by virtue of their relatively high latent heat of vaporization. The thermal efficiency of any engine using methanol as fuel can be increased if waste engine heat is available to convert the methanol to the gaseous state. The degree of improvement is greater with methanol than for ethanol.

### 3.3.2 In-Use Emissions with Alternative Fuels (Vol. IIIC - Section 9)

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 various types of prime movers. While the emission impact of each fuel/powerplant combination, not ruled out by non-emission considerations, needs to be evaluated, it is of interest to look at the contribution of non-highway transportation to the total emission burden, shown in Table 3-21. As indicated, the non-highway transportation emissions are a relatively minor contributor to the total U.S. emissions burden. However, particular modes can impact to a greater extent in localized areas. For example, aircraft could be a source of particulate and $NO_x$ near airports; emissions from railroads could be a problem in urban areas; and with some marine fuels, emissions may force the use of one fuel in port while another fuel could be used on the open seas.

#### 3.3.2.1 Emissions of Various Engine/Fuel Systems

In recent years, numerous investigators have studied the performance of various prime movers with non-petroleum 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. The major conclusions from these studies are summarized below.

- Alcohols

The use of alcohols in spark-ignition engines would lead to somewhat lower emission of CO, hydrocarbons, and $NO_x$, due to operating with leaner combustion. Aldehyde emissions are likely to be higher and there may be some unburned alcohol emissions.

## TABLE 3-21

## Non-Highway Transportation Contribution to U.S. Emissions

### U.S. Emissions, Millions Tons/yr

| Transportation | Particulates (1) | $SO_x$ (1) | $NO_x$ (1) | HC (1) | CO (1) | BaP (2) |
|---|---|---|---|---|---|---|
| Grand Total | 15.9 | 32.7 | 21.7 | 23.8 | 97.0 | $900 \times 10^{-6}$ |
| Railroads | 0.057 | 0.130 | 0.846 | 0.215 | 0.297 | $0.32 \times 10^{-6}$ |
| Aircraft | 0.162 | 0.038 | 0.155 | 0.486 | 0.836 | $0.24 \times 10^{-6}$ |
| Marine Vessels | 0.025 | 0.102 | 0.194 | 0.367 | 1.084 | $0.50 \times 10^{-6}$ |
| Pipelines | 0.002 | 0.010 | 0.185 | 0.046 | 0.028 | $0.10 \times 10^{-6}$ |
| Sub-Total | 0.246 | 0.280 | 1.380 | 1.114 | 2.245 | $1.16 \times 10^{-6}$ |
| % of Grand Total | 1.55 | 0.856 | 6.36 | 4.68 | 2.31 | 0.12 |

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(1) Derived from May 1976 report of the National Emission Data System.

(2) Benzo (α) pyrene - estimated in this study.

With a stratified charge spark ignition engine, there was an increase in CO and hydrocarbons and a decrease in $NO_x$ when alcohols were tested.

The use of alcohols in gas turbines would produce lower $NO_x$ and smoke emissions, but increased CO and hydrocarbon emissions. However, the CO and hydrocarbon emissions from a gas turbine are low, so emissions would not be a major factor to consider.

- Hydrogen

The use of hydrogen in a gas turbine would eliminate CO, $CO_2$, hydrocarbon and smoke emissions. There is conflicting data on the impact on $NO_x$ emissions.

- Other Gaseous Fuels

There are no major benefits or debits with gaseous fuels other than for ammonia. With ammonia, $NO_x$ emissions may be a problem.

- Coal and Shale Oil Liquids

The emissions from coal or shale oil liquids are expected to be the same as for petroleum fuels if the coal and shale liquids are refined to be fully equivalent. There may be a problem with $NO_x$ emissions due to potentially higher fuel nitrogen levels. Also, the higher aromatic content with coal liquids could cause increased smoke emissions and carcinogenicity problems with particulate emissions.

- Coal and Coal/Slurries

The use of coal in any type of prime move would cause problems in emission levels, especially in particulates.

#### 3.3.2.2 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 given in the Appendix Volume IIIC. 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.

### 3.3.3 Prime Mover - Fuel Interaction (Vol. IIIA - Section 4)

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.

The way a given fuel burns may make it incompatible with some types of engines. 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.

In the following sections, some of the critical fuel properties for each particular type of prime mover are discussed.

#### 3.3.3.1 Diesel Engine

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. As mentioned above, the measure of combustion quality for a diesel engine is 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, 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. Thus, cetane number consideration is less important for slower speed engines.

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, but other more aromatic fuels that can be expected from other coal liquefaction processes are not necessarily excluded, provided they are upgraded.

The diesel engine, in the sizes which are applicable to non-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 fuels containing undistilled residue, 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.

### 3.3.3.2 Gas Turbines (Open Cycle)

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.

Synthetics like liquid hydrogen, the alcohols, methane and low contaminant distillate fuels are all possible fuels 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.

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.

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

One potential problem on using alcohols in gas turbines is the possible contamination of the fuel with salt water--if transported by tanker or barge movement. Sodium contamination even at a concentration of one part per million of fuel can be very damaging in causing sulfidation of the 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.

### 3.3.3.3 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 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. Therefore, if certain liquids derived from coal, having perhaps very low cetane numbers, turn out to be poor in diesel operation the possibility remains that they might be used in free piston engines.

### 3.3.3.4 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 ratio, 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.

### 3.3.3.5 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 the working fluid--boiling water, air, hydrogen or helium, etc. Thus, the design problems are those normally faced by boiler manufacturers. 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 contemplated for these externally fired engines, will have to be studied carefully.

### 3.3.3.6 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:

| Fuel | Prime Mover |
|---|---|
| Powdered coal and coal/oil slurry | Diesel engine |
| Ammonia | Gas turbine |
| Coal | Gas turbine |

While diesel engines have been made to run on coal, in both cases there was a significant loss of efficiency and operating problems. In one case a fairly dilute slurry, 15% of solvent refined coal ground to 2 micrometers was used. Even with that careful preparation, the conventional fuel injection system plugged in short time.

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.

# 4. SELECTION OF ALTERNATE FUELS

## 4.1 Methodology and Ranking of Fuels
(Vol. IIIC - Section 13)
(Vol. IIIA - Section 2)

In the preliminary screening phase, a method has been developed that will allow one to select alternate fuels in a sound, logical, and technical manner. The main emphasis is on the fuels/prime mover/user interaction and it is assumed that technology is available to produce the fuels. The three major factors considered were: (1) fuel manufacture criteria; (2) fuel performance criteria; and (3) fuel logistics factors. A Likert scale was used to put the various factors on a basis which allows dissimilar factors to be combined into an overall ranking. The type of scale used allowed any given criterion of quality to be rated relative to some standard as

+2 signifying "much better"
+1 signifying "better"
0 signifying "equivalent or "don't know"
-1 signifying "inferior"
-2 signifying "much inferior"

In the fuel manufacturing area, three factors were considered; (1) the cost of production, distribution and storage; (2) overall energy efficiency up to point of use; and (3) the environmental impact in production.

The rating scale used for the cost of production, distribution and storage was as follows:

| Ranking | Cost Range - $/ M BTU (Delivered to Customer) |
|---|---|
| +2 | Up to 3 |
| +1 | 3 to 6 |
| 0 | 6 to 10 |
| -1 | 10 to 15 |
| -2 | > 15 |

The rating scale used for the overall energy efficiency category was as follows--

| Rating | BTU of Resource/BTU of Fuel |
|---|---|
| +2 | 1-1.3 |
| +1 | 1.31-1.7 |
| 0 | 1.71-2 |
| -1 | 2.01-2.5 |
| -2 | > 2.51 |

A similar rating scale was established for the environmental criteria. The overall environmental rating was then combined with the overall energy efficiency rating and the cost rating, to arrive at an overall manufacture rating, as shown in Table 4-1. Similar ratings were made for the fuel performance area (toxicity, safety, materials compatibility, storage requirements, convenience in handling and storage and environmental impact during use) and for the fuel logistics area (fuel availability, compatibility with present system, and international considerations). The rankings for these two areas are given in Tables 4-2 and 4-3.

To arrive at an overall ranking, the manufacturing, performance and logistics ratings were combined, assuming equal weight for the three areas, and are shown in Table 4-4. While the absolute numbers have no meaning, they do allow the fuels to be grouped into four areas for consideration in the detailed evaluation phase.

## 4.2 Compatibility of Fuels and Prime Movers (Vol. IIIC - Section 13)

In evaluating the performance potential for each fuel, it is necessary to consider the compatibility of the fuels and prime movers. A matrix was established for the 18 different fuels and the 8 different types of prime movers, and a rating established for each combination using a Likert scale ranging from the "best" where no modifications would be required to use the fuel in the current designs to the "worst" where it would not be practical to use the fuel since an entirely new design would be required. From this exercise it is possible to determine that some fuels simply are not potentially usable in certain types of engines, as shown in Table 6.

Based on this type of analysis, it is possible to get a semi-quantitative comparison of the relative difficulty of substitution of fuels, into the types of engines being considered in this study. The following list gives the relative ease of substitution of the fuels (listed in order of increasing difficulty of substitution). The broadcut fuel was considered for possible aircraft application.

1. Broadcut (petroleum)
2. Shale distillate
3. Coal 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

## TABLE 4-1

### Fuel Manufacture Criteria--Ratings

| Fuel | Cost Rating | Overall Energy Efficiency | Environmental Impact in Production | Overall Rating |
|---|---|---|---|---|
| Coal/Methanol Slurry | 0 | 0 | 0.3 | 0.1 |
| Coal/Oil Slurry | 2 | 2 | 0.7 | 1.6 |
| Coal | 2 | 2 | 0.7 | 1.6 |
| Coal Liquids | | | | |
| - Distillate | 0 | 0 | 0.3 | 0.1 |
| - Gasoline | 0 | 0 | 0.3 | 0.1 |
| Shale Liquids | | | | |
| - Distillate | 1 | 1 | -1 | 1 |
| - Gasoline | 1 | 1 | -1 | 1 |
| Methanol from | | | | |
| - Coal | -1 | 0 | 0.3 | -0.2 |
| - Biomass | -2 | 0 | 0 | -0.7 |
| Hydrogen (Liquid) from | | | | |
| - Coal | -2 | -2 | 0.3 | -1.2 |
| - Electrolysis | -2 | -2 | 0 | -1.3 |
| Ammonia from | | | | |
| - Coal | -2 | -1 | 0 | -1.0 |
| - Biomass | -2 | 0 | 0 | -0.7 |
| Oxygenated Compounds | | | | |
| - Ethanol--Corn | -2 | 0 | 0 | -0.7 |
| - Ethanol--Sugarcane | -2 | 0 | 0 | -0.7 |
| Methane (Liquid) from | | | | |
| - Coal | -1 | 0 | 0.3 | 0.2 |
| Hydrazine | -2 | -1* | 0 | -1.0 |

## TABLE 4-1 (Cont'd)

### Fuel Manufacture Criteria--Ratings

| Fuel | Cost Rating | Overall Energy Efficiency | Environmental Impact in Production | Overall Rating |
|---|---|---|---|---|
| Methylamine | -2 | -1* | 0 | -1.0 |
| Acetylene | -2 | -2 | 0 | -1.3 |
| Oil from Organic Waste | -1 | 0 | 0 | -0.3 |
| Electricity from | | | | |
| - Coal/Nuclear | -1 | -2 | -0.3 | -1.1 |
| - Solar | -2 | 0 | 0 | -0.7** |

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*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.

## TABLE 4-2

## FUEL PERFORMANCE CRITERIA

| | | | | Storage Requirements | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Fuel | Toxicity | Safety | Materials Compatibility | Weight (Fuel Only) | Volume (Fuel Only) | Avg. | Convenience in Handling and Storage | Environmental Impact During Use | Overall Rating |
| 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 |

## TABLE 4-3

## 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 |

## TABLE 4-4

## Overall Ranking of Fuels for Non-Highway Transportation

| | Criteria | | | |
|---|---|---|---|---|
| Fuel | Manufacture | Performance | Logistics | Overall |
| Shale Liquids | | | | |
| Raw Shale Oil | 1 | 0 | -0.8 | +0.2 |
| Syncrude-Gasoline | 1 | 0 | 0 | 1 |
| -Distillate | | | | 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 |
| Methane from Coal | -0.2 | +0.3 | -0.8 | -0.7 |
| Oil from Organic Waste | -0.3 | -0.1 | -0.5 | -0.9 |
| Oxygenated Compounds | | | | |
| Ethanol-Corn | -0.7 | -0.7 | -0.3 | -1.7 |
| Ethanol-Sugarcane | -0.7 | -0.7 | -0.3 | -1.7 |
| Methanol from | | | | |
| Coal | -0.2 | -0.7 | -0.8 | -1.7 |
| Biomass | -0.7 | -0.7 | -1.0 | -2.4 |
| Electricity from | | | | |
| Coal | -1.1 | | -1 | -2.1 |
| Nuclear | -1.1 | N/A | -1 | -2.1 |
| Other Solar | -0.7 | | -2 | -2.1 |
| Coal/Methanol Slurry | 0.1 | -1.2 | -1 | -2.1 |
| 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 |
| Hydrazine | -0.7 | -1.3 | -2 | -4.3 |
| Methylamine | -0.7 | -1.4 | -2 | -4.4 |
| Acetylene | -1.3 | -1 | -2 | -4.3 |

It is also possible to obtain a semi-quantitation comparison of which types of prime movers have the greatest degree of flexibility for using different types of fuels. The following is a list of the prime movers in descending order of fuel flexibility:

1. Boiler/steam turbine
2. Stirling
3. Stationary non-aircraft 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.

### 4.3 Selection of Fuels and Prime Movers for Each Mode of Non-Highway Transportation (Vol. IIIC - Section 14)

One of the major objectives of the preliminary screening was to narrow down the best of alternate fuels and prime movers for more detailed evaluation. The same methodology described above was used to rank the fuels that would be of potential interest for each type of prime mover. The various prime movers of interest for each mode of non-highway is shown in Table 4-6. In some cases, the number of prime movers is greater than can be included in an in-depth study. In these cases the list of prime movers was narrowed down, based on the characteristics of the type of engines used in each mode of transportation.

The fuels and prime movers recommended for consideration in the detailed evaluation phase are shown in Tables 4-7 through 4-10. The numbers shown indicate the relative ranking of the fuels for each type of prime mover. This is a preliminary ranking.

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*Non engine related fuel factors would move aircraft gas turbine further down the list.

## TABLE 4-5

## Summary of Fuel/Engines That Are Incompatible

| Fuels | Otto Cycle |  | Diesel |  | Gas Turbine |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|
|  | Normal Spark | Stratified Charge | Marine | Railroad | Stationary(1) | Aircraft | Stirling | Free Piston | Steam |
| 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 | X |  | 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 |  | X |  |  |  |
| Oil - Organic Waste | 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.

## TABLE 4-6

## Prime Movers of Interest for Non-Highway Transportation

| | Mode of Transportation | | | |
|---|---|---|---|---|
| Type of Prime Mover | Pipeline | Rail | Marine | Aircraft |
| 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 4-7

## Fuels/Prime Movers Selected for In-Depth Study for Aircraft

| Fuel | Gas Turbine | Otto Normal Spark Ignition(1) |
|---|---|---|
| Shale Distillate | 1 | |
| Coal Distillate | 2 | |
| Methane (ℓ) | 3 | |
| Hydrogen (ℓ) | 4 | |
| Broadcut Petroleum | Not Rated | |

---

(1) Will not be covered in-depth. Possible fuel of interest are gasoline (from shale or coal), ethanol, methanol, and methane (ℓ).

## TABLE 4-8

## Fuels/Prime Movers Selected for In-Depth Study for Pipeline

| Fuel/Energy Carrier | Diesel* (Med. Speed) | Stationary* Gas Turbine | Otto Cycle | | Electric Motor | Fuel Cell |
|---|---|---|---|---|---|---|
| | | | Stratified Charge | Spark Ignited | | |
| 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** | |

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*Will include combined cycle consideration.
**Will be included in study.

# TABLE 4-9

## Fuels/Prime Movers Selected for In-Depth Study for Railroads

| Fuel/Energy Carrier | Diesel | Steam Engine | Stirling Engine | Gas Turbine | Electric(1) | Fuel Cell |
|---|---|---|---|---|---|---|
| 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 4-10

## Fuels/Prime Movers Selected for In-Depth Study for Marine

| Fuel | Diesel | Steam Engine | Free Piston | Gas Turbine | Stirling | Fuel Cell |
|---|---|---|---|---|---|---|
| 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 | | | | |

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*Light distillate

# 5. PIPELINES

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## 5.1 Background

Pipeline systems can be divided into three basic types; liquids, gases, and slurry pipelines. The liquid pipelines can be subdivided into crude oil lines, petroleum product lines, water supply, waste water lines, and special products such as petrochemicals, liquid ammonia, etc. In the future, coal derived liquids, shale oil based liquids, and alcohols could also be moved by pipeline. The major gas moved via pipeline is natural gas, but other gases are moved today over relatively limited distances. In the future, low or medium BTU gases, SNG from coal, and hydrogen may also be moved by pipeline. Two coal-water slurry pipelines have been built and operated and several are in the planning stage. In the future, coal-methanol slurries have also been proposed as an alternate to coal-water slurries.(5-1) A recent study by Banks, et al(5-2), gives the energy consumption for the various types of pipeline, which is summarized below.

| | Energy Consumption, Quads, 1976 |
|---|---|
| Gas | |
| Natural Gas | 0.71 |
| Liquids | |
| Crude Oil | 0.07 |
| Petroleum Products | 0.068 |
| Water Supply | 0.05 |
| Waste Water | 0.017 |
| Slurry | |
| Coal-Water | 0.0044 |

### 5.1.1 Type of Prime Movers Used for Various Types of Pipelines

#### 5.1.1.1 Petroleum Liquids

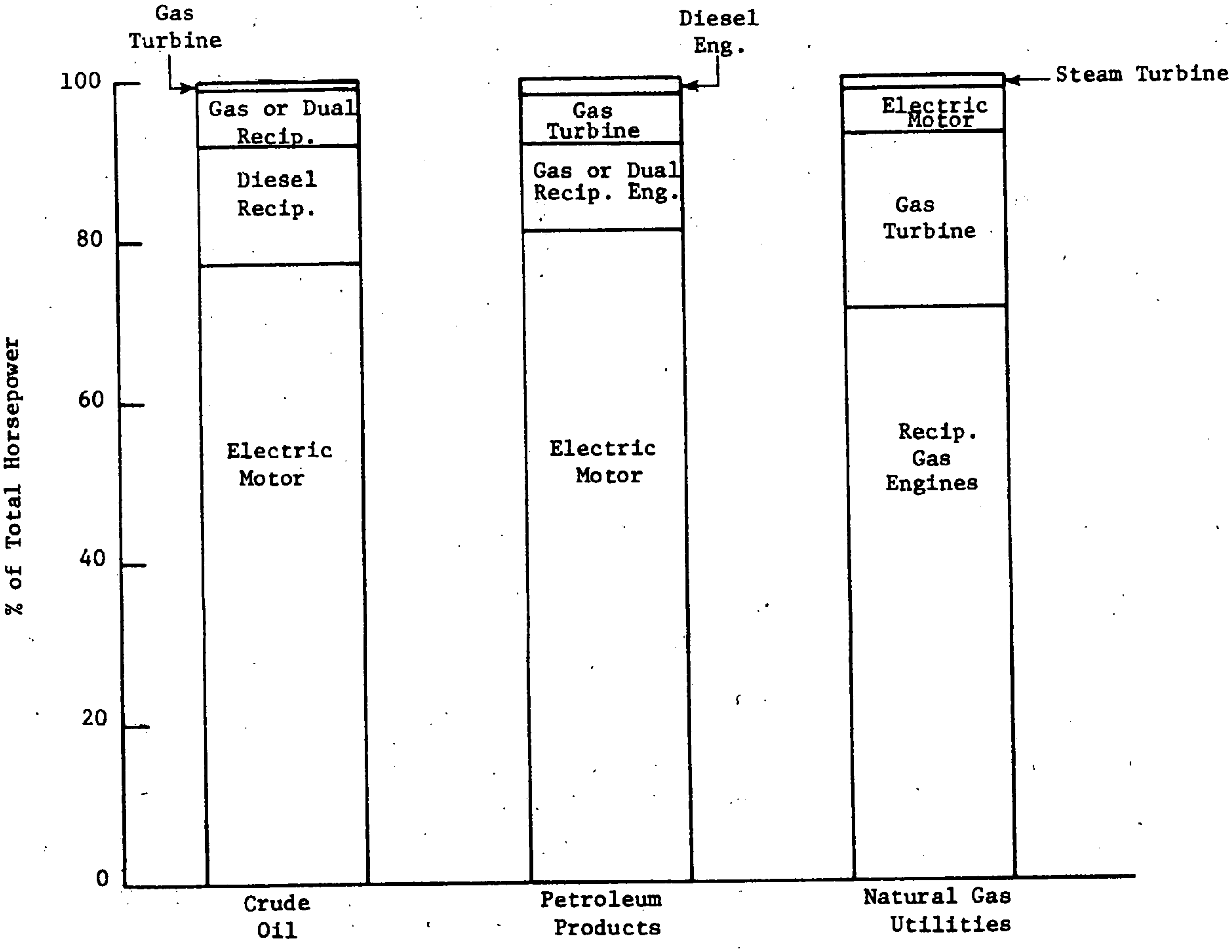
The majority of prime movers for petroleum liquids, crude and products, are electric motors. As shown in Figure 5-1, 77% of the installed pump horsepower for crude oil was supplied by electric motors, while 15% of the pumps were driven by diesel engines. With petroleum products, 81% of the drivers were electric motors, while gas reciprocating engines and gas turbines supply the balance of the drivers. Details are given in Table 5-1. One advantage for electric motors is that the motors can be controlled remotely and no manpower is required on site. One disadvantage

FIGURE 5-1

Installed Compressor & Pump Horsepower for Petroluem Liquid & Natural Gas Pipelines

1970-71

Percent of Total Horsepower



# TABLE 5-1

## Installed Pump Horsepower (BHP) - Petroleum Liquids Pipeline

1970-71

| | Crude Oil | | Products | |
|---|---|---|---|---|
| | BHP | % | BHP | % |
| Reciprocating Gas Engines - Gas | 147,280 | 3 | 6,120 | <1 |
| - Diesel/Gas | 211,230 | 4 | 178,430 | 11 |
| SUB TOTAL | 358,510 | 7 | 184,550 | 11 |
| Diesel Engine | 783,590 | 15 | 28,890 | 2 |
| TOTAL RECIPROCATING | 1,142,100 | 22 | 213,440 | 13 |
| Gas Turbine | 65,520 | 1 | 100,940 | 6 |
| Steam Turbine | 1,050 | <1 | - | - |
| Electric Motor | 4,032,700 | 77 | 1,384,920 | 81 |
| TOTAL | 5,241,370 | 100 | 1,699,300 | 100 |

Source: Reference 5-2

with constant-speed AC motors is that throttling of the liquid flow is sometimes necessary to control thruput and this can result in waste of energy. 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.

#### 5.1.1.2 Natural Gas Utilities

As shown in Figure 5-1, in 1970-71 reciprocating gas engines accounted for 71% of the installed compressor horsepower in the movement of natural gas. Gas turbines account for another 22% of the installed prime movers, so that together, 93% of the compression energy is supplied by gas taken from the pipeline. Whether this will be economical in the future, as the value of the gas being transmitted increases, is one of the questions that will be answered by this study. The distribution of the natural gas installed compressor horsepower between transmission, distribution, storage, and field and gathering is given in Table 5-2.

#### 5.1.1.3 Water Pumping

Water pumping can be subdivided into three groups: (1) agricultural wells, (2) municipal water and sewage, and (3) the California aqueduct. The type of prime mover and installed horsepower for these three areas are as follows:

| | Installed Horsepower | Type of Prime Movers |
|---|---|---|
| Agricultural Wells | 7,500,000 | 100% diesel engines |
| Municipal Water & Sewage | 930,000 | 50% electric<br>50% reciprocating |
| California Aqueduct | 900,000 | 100% electric |

Source: Reference (5-4)

#### 5.1.1.4 Coal-Water Slurries

The longest and largest coal-water slurry pipeline built to date is the Black Mesa line connecting the Black Mesa, Arizona, coal field to the Mohave Generating Station in southern Nevada. Four pump stations are required, utilizing piston pumps with electric motor drives and hydraulic couplings for speed control.(5-1)

### 5.1.2 Factors Considered Important in Prime Mover-Fuel Selection

The factors that are considered in selecting a type of prime mover and the fuel to be used are as follows:

- Initial installation cost
- Energy cost

## TABLE 5-2

## Installed Compressor Horsepower in Natural Gas Utilities

| | Installed Compressor and Pump Horsepower (BHP) | | | | | |
|---|---|---|---|---|---|---|
| | Natural Gas Utilities Only | | | | | |
| Compressor Drive | Transmission | Distribution | Storage | Field + Gathering | Total | % |
| Recip. Gas Engine | 7,573,030 | 680,760 | 1,042,390 | 1,540,225 | 10,836,405 | 71 |
| Diesel | - | 16,740 | - | | 16,740 | <1 |
| Dual Fuel | - | - | - | | - | |
| Total Recip. | 7,573,030 | 697,500 | 1,042,390 | 1,540,225 | 10,853,145 | 72 |
| Gas Turbine | 3,090,940 | - | - | 264,160 | 3,355,100 | 22 |
| Steam Turbine | 129,540 | 42,180 | - | - | 171,720 | 1 |
| Electric | 470,850 | 333,570 | - | - | 804,420 | 5 |
| Total Horsepower | 11,264,360 | 1,073,250 | 1,042,390 | 1,804,385 | 15,184,385 | |
| Pipeline Miles | 252,621 | 595,653 | 3,704 | 66,556 | | |

Source: Reference 5-2

- Maintenance and operating cost
- Maintenance and operating manpower
- Available energy supply. In the future it will be important to consider this as a non-petroleum source.
- Reliability
- Multiple relocation possibilities, i.e. - can the equipment be used at more than one site.

Each of these factors will be considered in the final ranking of the fuels and prime movers.

## 5.2 Summary and Conclusions

### 5.2.1 Liquids Pipelines

- The electric motor is expected to be the most economical prime mover over the size range considered, 500 to 5000 horsepower, provided the cost of the fuel used for a diesel or gas turbine costs more than $4/MBTU.

- If the cost of liquid fuels is less than about $4/MBTU than either a diesel or a gas turbine would give a lower total annual cost. All of the alternate fuels considered as possible fuels for pipeline service have a cost greater than $4/MBTU; therefore, it is unlikely any of these would be used in place of electric motors, unless the cost of providing electric power to a site was very high.

- The choice between a diesel engine and a gas turbine driver would depend on the size. At the 500 hp size the two types are about equal in annual cost. Above this size range the gas turbine is cheaper to operate. The gas turbine has a lower initial investment and maintenance cost but the annual fuel costs are greater than for a diesel engine.

- In addition to being more economical on an annual cost basis, the electric motor is also more attractive from the initial cost standpoint; can be controlled from remote locations, and is preferred from a total energy conservation standpoint. If the electric power is generated by coal or nuclear power, then the liquid pipeline energy requirements can be converted to non-petroleum sources.

- There is no incentive to consider the use of fuel cells for liquid pipeline applications.

### 5.2.2 Gas Pipelines

- The most economical and overall energy efficient prime mover-fuel combination is the electric motor using coal or nuclear energy to generate the electricity, as long as the fuel cost is greater than $4-5/MBTU. This means that it is more economical to use an electric motor drive to compress SNG or hydrogen rather than a gas turbine or gas reciprocating engine using SNG or hydrogen from coal as the fuel. The cost of both of these fuels is expected to exceed $5/MBTU.

- The geographical location of the pipeline has a major impact on what is practical. If the compressor station is very large or if an electrical power system is not reasonably close, the economics could change in favor of a gas turbine driver.

- With a low or medium BTU gas it may be more attractive to use a gas turbine, depending on the cost of electricity. A site specific study would be required to answer this question.
- In the smaller size ranges of 500 hp, the annual cost of operation for an electric motor, a gas turbine, and a gas engine are essentially equal. As the size of the driver increases, the electric motor becomes more attractive.
- On an annual cost basis, there is a small advantage for a molten carbonate fuel cell compared to a gas turbine and gas engine. There is no advantage for a $H_3PO_4$ electrolyte fuel cell for gas pipeline application.
- Molten carbonate fuel cells are not projected to be as attractive as electric motors for gas compression at the investment level assumed in this study. A 25% reduction in investment would be required for the annual operating cost for a fuel cell system to be breakeven with an electric motor drive.
- Fuel cells do have a significant advantage over gas turbines in fuel efficiency at part load. However, in actual practice, this situation is generally handled by adding compression capacity in increments and running all units at maximum capacity.
- There does not appear to be enough incentives for the use of fuel cells in gas transmission operations to justify supporting the development of fuel cells for this purpose alone. If fuel cells are commercialized for other applications, their potential for use in pipeline services should be considered when better information on costs and efficiencies becomes available. It is not expected that molten carbonate fuel cells will be available commercially before 1990. Presumably, these conclusions will be firmed up by the contracted study on applications of fuel cells to pipeline operations being made for the Department of Energy.

## 5.3 Economic Factors

Since economics is a major factor in selecting the type of prime mover and the fuel, comparisons have been made among the investment, maintenance and operating and fuels costs for various conventional types of prime movers. In addition, similar estimates were made for fuel cells for gas pipeline applications. The basic cost relationships were developed by Exxon Pipeline Company, from literature references and are presented in Appendix 5-A. along with a sample calculation to illustrate their application. Estimates of the cost and operating characteristics of the fuel cells studied were obtained from United Technologies Corporation (UTC) and these data are also included in Appendix 5-A. The fuel cells are described in the appendix Volume A.

Investments, as calculated from the relationships given in Appendix Table 5-A-1, represent the total capital costs for each pipeline compression station. These costs include prime mover, compressor, controls, piping and land required, but exclude storage tanks, dehydration equipment, housing, major office structures and major site improvements if they are required.

### 5.3.1 Liquid Pipeline Prime Movers

In considering the type of prime movers to consider for future application, the types of prime movers now in use serve as a good starting point. Therefore, the three basic types of prime movers considered are the diesel reciprocating engine, a gas turbine, and an electric AC motor (constant speed drive) each with a centrifugal pump. Table 5-3 summarizes the efficiencies used for each of these prime movers. For all cases a constant "pipeline horsepower" (PHP) of 2000 HP was used, resulting in a prime mover horsepower requirement of 2500 for a pump efficiency of 80%. It was assumed that a single unit would be required, except for the constant speed AC motor case, where it was assumed that three units would be required. The basis for the investments are given in Appendix 5-A. The annual operating cost are based on three factors.

(1) A capital charge of 20%, which may be lower than would be acceptable to most pipeline companies since this represents about a 10% DCF. If a higher capital recovery factor, representative of a 15% DCF is used, then the electric AC motor case becomes even more attractive.

(2) Maintenance cost, and

(3) An energy cost which is a function of the thermal efficiency of the prime mover and the assumed fuel cost. The data shown in Table 5-3 are based on a liquid fuel cost of \$4.9/MBTU and an electricity cost of 5.1¢/KWH.

Based on the information in Table 5-3, several observations can be made about the three types of drives.

- From an initial investment standpoint, the electric motor is the most attractive, followed by the gas turbine, and then the diesel, as shown below.

Investment - for a Single Unit (\$1980)

| | | For a 2000 PHP Requirement |
|---|---|---|
| Electric Motor - Constant speed | 308k\$ + \$123/HP | 500k\$ |
| Gas Turbine | 460k\$ + \$308/HP | 1230k\$ |
| Diesel | 430k\$ + \$461/HP | 1580k\$ |

## TABLE 5-3

## Liquid Pipeline Prime Mover Economics

| | Diesel Engine + Centrifugal Pump | Advanced Gas Turbine + Centrifugal Pump | Electric AC Motor + Centrifugal Pump |
|---|---|---|---|
| | | | Constant Speed |
| **Efficiencies, %** | | | |
| Prime Mover (LHV) | 38 | 34 | -- |
| Pump | 80 | 80 | 80 |
| Motor | -- | -- | 95 |
| HP Required-- Prime Mover | 2500 | | |
| Number of Units | 1 | 1 | 3 |
| Investment - $M (1980) | 1.58 | 1.23 | .65 |
| **Annual Cost, $M/yr** | | | |
| Capital Charges | .32 | .25 | .12 |
| Maintenance & Operation | .13 | .098 | .05 |
| Energy(1) | .66 | .72 | .80 |
| TOTAL | 1.11 | 1.07 | 0.97 |

---

(1) Assumed fuel cost of $4.9/MBTU for diesel and gas turbine and 5.1¢/KWH for electricity.

- The maintenance cost is in the same rank order as the initial investment, as shown below.

| | k$/yr for 2000 PHP Case |
|---|---|
| Electric Motor | 49 |
| Gas Turbine | 98 |
| Diesel | 135 |

- The energy cost, however, is in the reverse sequence, based on the fuel cost assumed; as shown below.

| | k$/yr for 2000 PHP Case | Fuel Cost $/10^6 BTU |
|---|---|---|
| Diesel | 656 | 4.9 |
| Gas Turbine | 723 | 4.9 |
| Electric Motor | 803 | 14.9 (5.1¢/KWH) |

- On a total annual cost basis, the electric motor is still the most attractive, as shown below.

| | Annual Cost-k$/yr-2000 PHP Case | |
|---|---|---|
| | 20% Capital Recovery (~10% DCF) | 32% Capital Recovery (~15% DCF) |
| Electric Motor | 970 | 1060 |
| Gas Turbine | 1070 | 1210 |
| Diesel | 1110 | 1300 |

- The cost of energy represents 60-80% of the total annual operating cost.

#### 5.3.1.1 Variation of Annual Cost for Various Type Prime Movers with Size of Driver

The comparisons shown above have been for the case where 2000 pipeline horsepower is required. Since the investment and maintenance cost are made up of a fixed and a variable cost term, it is necessary to see if the same ranking holds up over the range of interest, 500 to 5000 PHP. As shown in Figure 5-2, for a fuel cost of $4.9/MBTU for liquid fuel and 5.1¢/KWH for electricity, the electric AC motor is the most attractive type of prime mover. At the 500 HP size the diesel and gas turbine have the same annual cost.

#### 5.3.1.2 Effect of Fuel Cost on Selection of Prime Mover Type

The effect of fuel cost on the selection of the type of prime mover for liquid pipeline operation is shown in Figure 5-3. At a fuel cost of \$8/MBTU the diesel and gas turbine have about the same annual operating cost. Below \$8/MBTU, the gas turbine has a lower operating cost, even though it has a lower thermal efficiency. All of these comparisons are based on an advanced gas turbine design with a 34% efficiency. At the thermal efficiency typical of current designs, the diesel is clearly more economical than the gas turbine. The annual cost for the electric motor is shown for the variable speed case and for an electricity cost of 5.1¢/KWH and 4.2¢/KWH. The 4.2¢/KWH is based on a bus bar electricity cost of 3.3¢/KWH, and a distribution cost of 0.9¢/KWH, half of what was used in the base case. Thus, with electricity available at 5.1¢/KWH, the electric motor will breakeven with the diesel at a fuel cost of \$4.4/MBTU and with the gas turbine at a fuel cost of \$4.8/MBTU. All of the liquid fuels considered in this study have a delivered fuel cost greater than \$4.9/MBTU, therefore if electricity is available at the pump site, it would be the preferred type of prime mover.

In this comparison it is assumed that electric power lines are close to the site. If this is not the case, charges may be incurred for connection to the main lines. For example, installation of a 500 hp booster motor costs \$20,000 for a power line to be built seven miles to the site.(5-5) In some cases, the charges have been considerably higher - around \$100/hp for new electrical facilities. While these high rates may apply in only a few cases, they need to be considered for any site specific studies.

#### 5.3.1.3 Potential for Fuel Cell in Liquid Pipeline Service

In Section 3.1.2.1.4, the possibilities of utilizing fuel cells to power pumps and compressors in pipeline systems were discussed. For liquid oil pipelines, the majority of the pumping in the U.S. is accomplished through use of AC motors connected to utility grid power, as discussed above. It was concluded that it is unlikely that fuel cells could produce electric power at relatively small local pumping station sites at lower cost than would be available from utility central stations. Furthermore, the capital investment required for the pipeline operator would be considerably higher in the fuel cell case. This question is to be examined in more detail in a study being made for the Department of Energy, and no further consideration of this application will be included here. The comparison of fuel cells to other types of prime movers will be made for gas pipeline applications.

### 5.3.2 Gas Pipeline Prime Movers

With gas pipelines, the major type of prime mover in use today is the reciprocating gas engine, with a reciprocating compressor using natural gas directly from the line as fuel. The gas turbine has also been used with centrifugal compressors as well as the electric motors

FIGURE 5-2

Variation of Annual Cost for Various Types of Prime Movers for Liquid Pipelines as a Function of Pipeline Horsepower Requirement

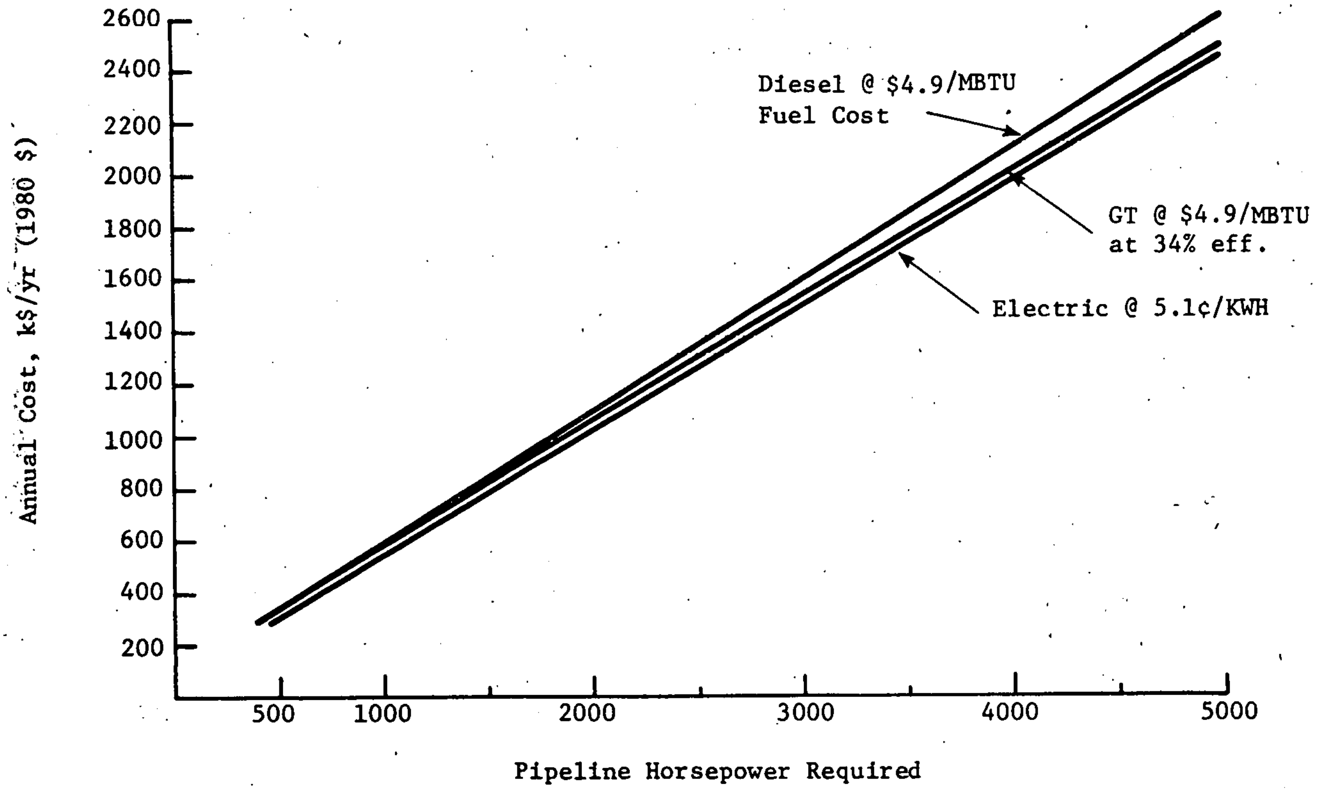
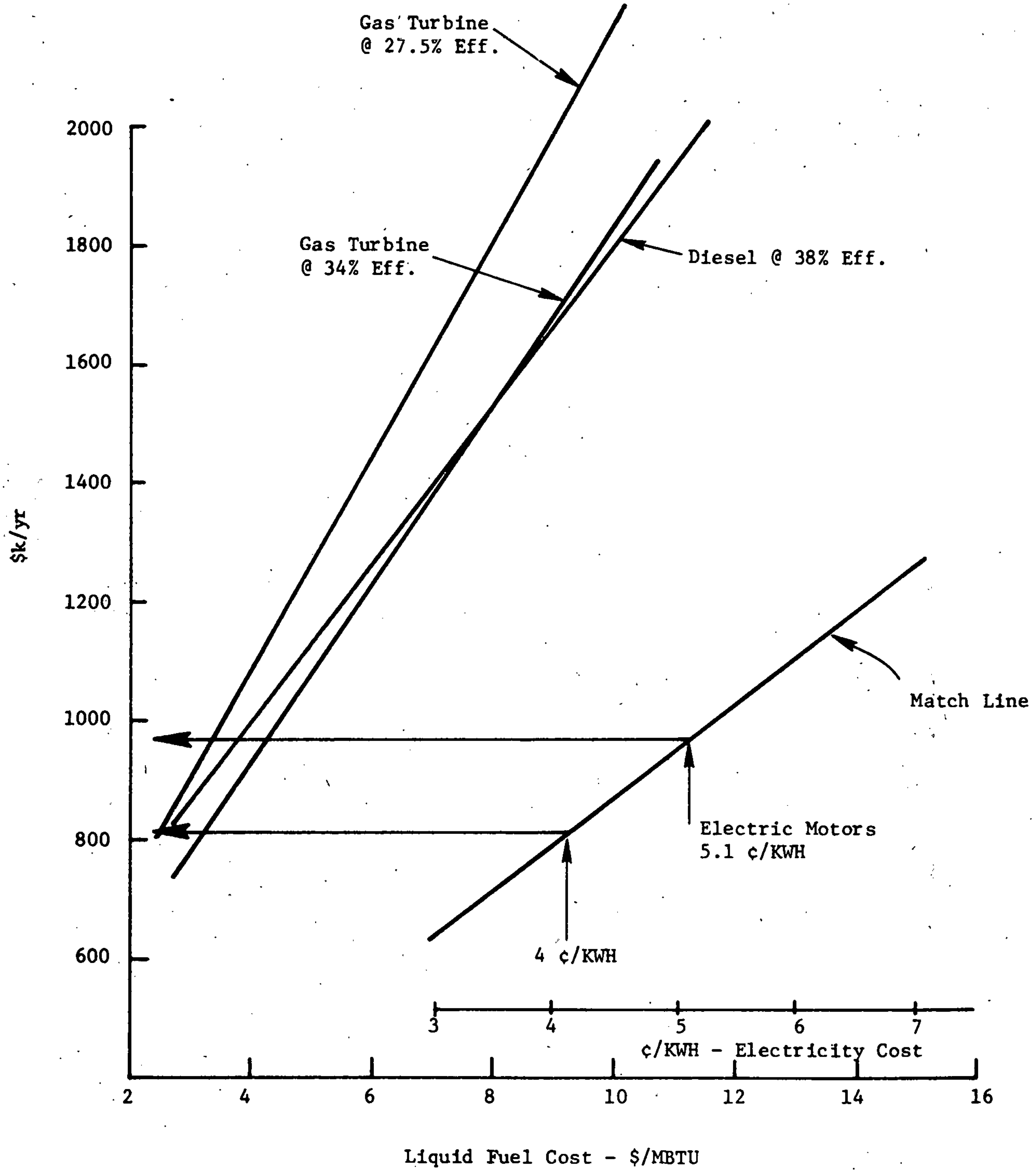


FIGURE 5-3

Effect of Fuel Cost on Selection of Prime Mover-Liquid Pipeline



# TABLE 5-4

## Gas Pipeline Prime Mover Economics

| | Gas Turbine + Centrif. Compress. | Recipr. Gas Engine + Recipr. Compress. | AC Motor on Utility Grid + Centrif. Compress. |
|---|---|---|---|
| **Efficiencies, % (LHV)** | | | |
| Prime Mover (LHV) | 34 | 39 | -- |
| Inverter | | | |
| Compressor | 80(1) | 80(1) | 80(1) |
| Motors | | | 95 |
| Gears | | | |
| HP Required - Prime Mover | 6250 | 6250 | 6250 |
| No. of Units | 1 | 1 | 3 Mot/Comp |
| Investment, $M | 2.93 | 4.04 | 2.11 |
| **Annual Costs, $M/yr** | | | |
| Capital Charges | 0.59 | 0.81 | 0.42 |
| Maintenance & Operation | 0.25 | 0.40 | 0.24 |
| Energy | 2.17 | 1.89 | 1.98 |
| TOTAL | 3.01 | 3.10 | 2.64 |

---

(1) Efficiency could also be as high as 90%. 80% used in this study for comparative purpose only.

with centrifugal compressors. These are the three types of prime movers that will be considered, plus the use of fuel cells to operate a DC motor driving a centrifugal compressor.

The gas pipeline mover economics are summarized in Table 5-4 for the three types of prime mover being considered. All three prime movers are compared for a constant "pipeline horsepower" (PHP) of 5000, resulting in a prime mover horsepower requirement of 6250 HP for an assumed 80% compressor efficiency. The efficiencies assumed for each type of prime mover are shown in Table 5-4, as well as the number of units used for each case.

Based on the information in Table 5-4, several observations can be made about these three types of drivers.

- From an initial investment standpoint, the electric motor is the most attractive, followed by the gas turbine.
- The maintenance cost for the electric motor and the gas turbine are essentially the same, with the reciprocating gas engine having a higher maintenance cost.
- The energy cost, at an assumed gas price of $5.9/MBTU, is the lowest for the gas reciprocating engine, followed by the electric motor and the gas turbine.
- On a total annual cost basis, the electric motor case is the most attractive for the conditions assumed.
- The cost of energy represents 60-75% of the total annual operating cost.

### 5.3.2.1 Variation of Annual Cost for Various Types of Gas Prime Movers with Size of Driver

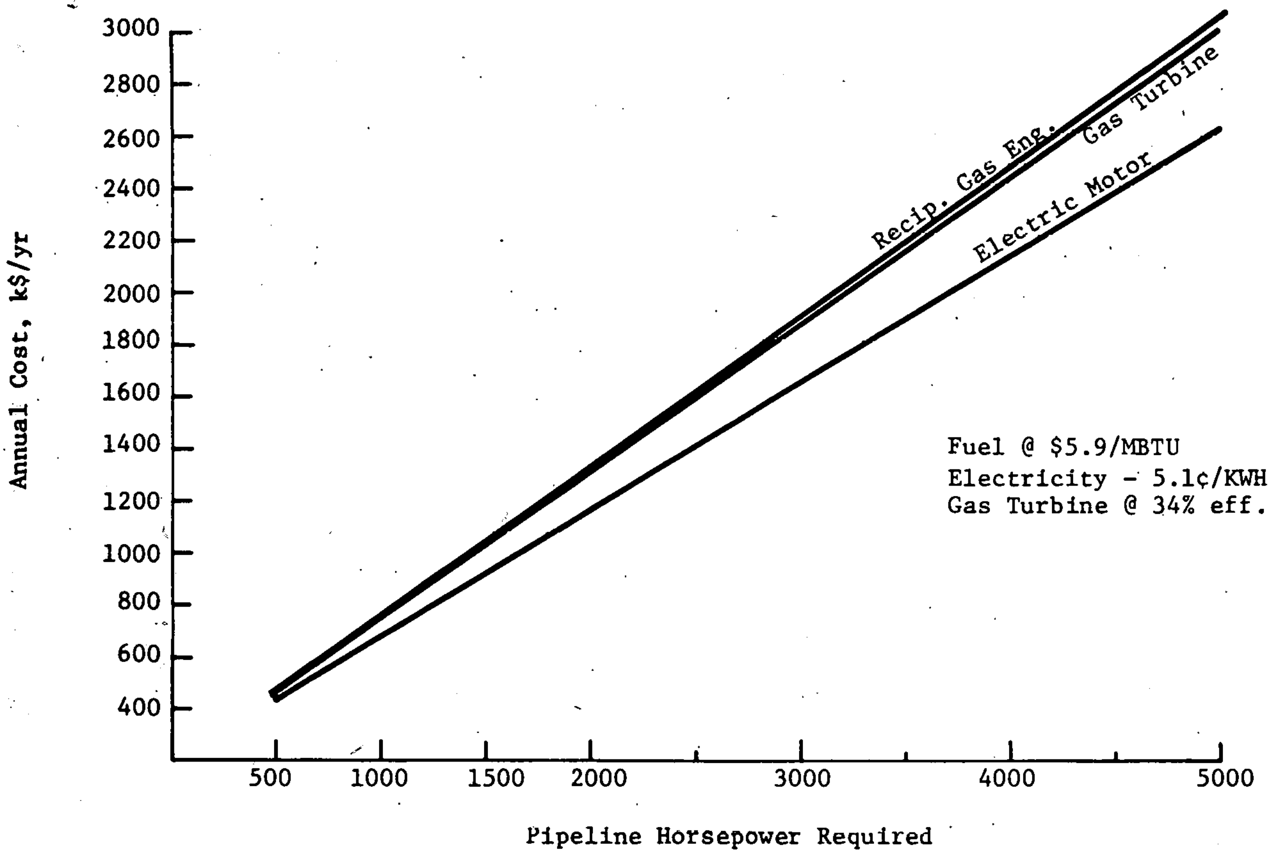
The comparison shown above was for the 5000 pipeline horsepower case. Figure 5-4 shows how the annual cost compares for the three different types of prime movers as a function of compressor horsepower required. A gaseous fuel cost of $5.9/MBTU is assumed and an electric power cost of 5.1¢/KWH. At the smaller size range, all three types of prime movers are an economic standoff. As the size of the compressor requirement increases, the electric motor becomes more attractive in the 500-5000 hp range. The economics between the reciprocating gas engine and the gas turbine are very close and other factors would determine which type of prime mover would be used.

### 5.3.2.2 Effect of Fuel Cost on Selection of Prime Mover Type

The effect of fuel cost on the selection of the type of prime mover for gas pipelines is shown in Figure 5-5. The gas turbine is the most economical below a gas cost of $5/MBTU. This assumes an advanced gas turbine with a 34% thermal efficiency. At the current thermal efficiency of 27.5%, the breakeven point between a reciprocating gas engine and a gas turbine is at a gas cost of about $3/MBTU. If the cost of electricity

FIGURE 5-4

Variation of Annual Cost for Various Types of Prime Movers for Gas Pipeline as a Function of Pipeline Horsepower Required



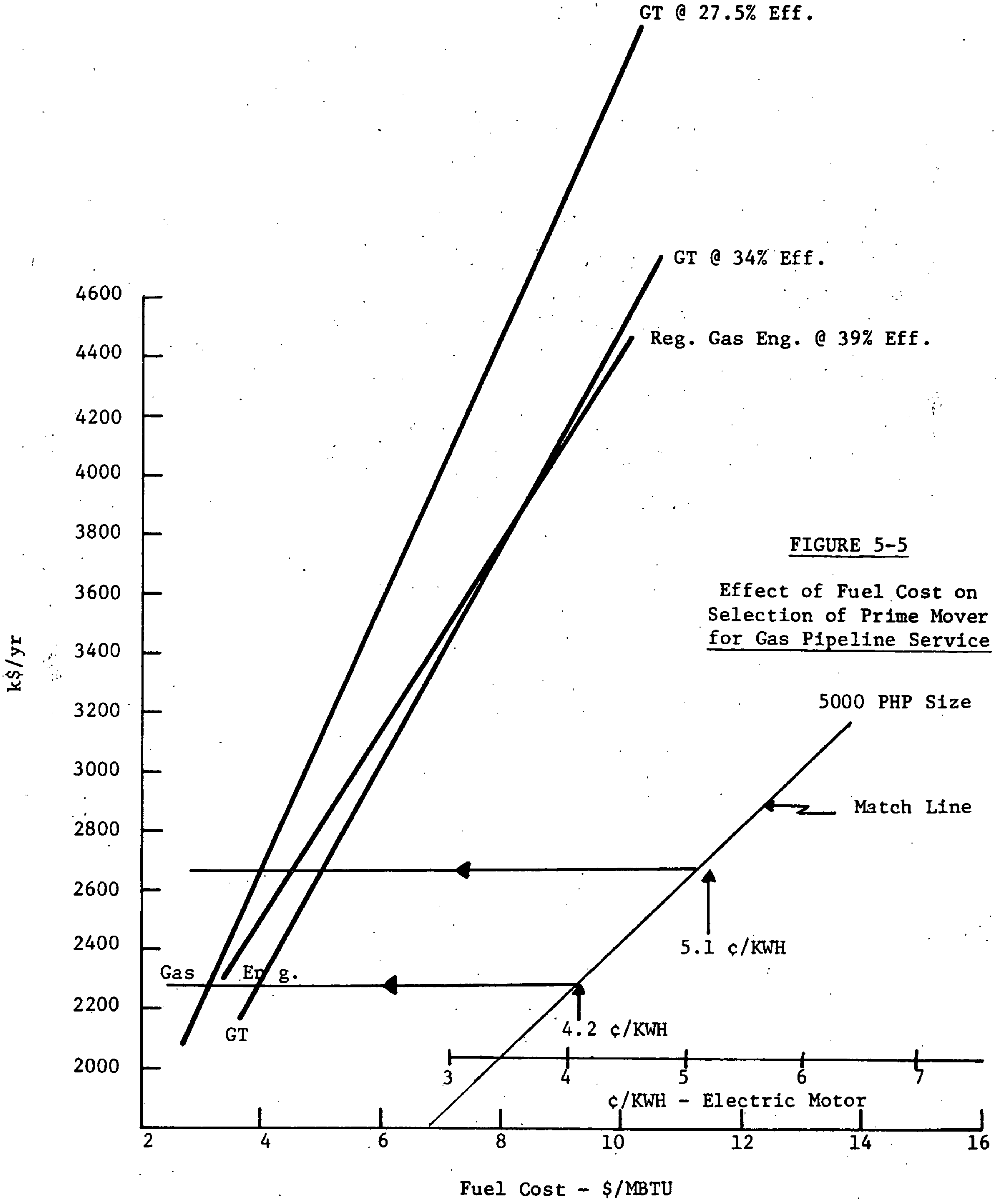


FIGURE 5-5

Effect of Fuel Cost on Selection of Prime Mover for Gas Pipeline Service drops to 4.2¢/KWH (3.3¢/KWH at the bus bar and 0.9¢/KWH distribution cost; half of the assumed cost) the breakeven point drops to $4/MBTU. The breakeven point between the gas turbine and the reciprocating engine is $8/MBTU, for this size driver.

Thus, if the cost of the gas being moved is greater than $4-5/ MBTU, it would be more economical to use electric motor drives rather than gas turbines or gas reciprocating engines. This would imply that SNG and $H_2$ (produced from coal or via nuclear power) should not be used as the fuel for gas compression--an electric driver would be more economical. In the past, when natural gas was priced at $1-2/MBTU, the gas turbine or the gas reciprocating engine was the most economical type driver.

These comparisons assume that electric power is reasonably close the the site. The location of the pipeline can have a bearing on what is practical. If a power plant would need to be built especially for the pipeline load, the electrical rates may be considerably higher than assumed in this study.

The only case where it may be more attractive to use a gas turbine rather than an electric drive would be for compressing low/medium BTU gas. In this study, the cost of producing a medium BTU gas is estimated at $4.25/MBTU, so that depending on the cost of electricity, an electric motor may not be more economical. A site specific study would be required to make this decision.

#### 5.3.2.3 Potential for Fuel Cells in Gas Pipeline Service

It is possible that fuel cells might economically be utilized in gas pipeline compression operations. In this case, DC power from the fuel cell would be used to operate DC motors driving centrifugal compressors. One advantage of this application is that weight and volume required for the fuel cell would not be limited, as they may be in mobile applications such as locomotives and ships. At the present time in the U.S., most natural gas transmission line compression is accomplished through use of combustion turbines driving centrifugal compressors or reciprocating gas engines operating reciprocating compressors. However, as pointed out in Section 3.1.2.1.4, the efficiencies available from present and known advanced design prime movers are at least as good as can be projected for $H_3PO_4$ electrolyte fuel cells, and close to those expected from molten carbonate fuel cells.

Nevertheless, a rough economic comparison was made among the current combustion turbine and reciprocating engine types of prime movers and the two types of fuel cells. Advanced versions of the conventional drivers were also considered. The comparisons were made for a compressor station of 6000 to 7000 HP (a large percentage of all compressor stations in the U.S. are this size or smaller) because at high capacities combustion turbines have a relatively greater advantage over fuel cells in cost per horsepower than they do at the 6000 to 7000 HP level. A case was also worked for driving a centrifugal compressor with an AC motor taking power from a utility grid; at the relative energy costs projected for the future in this study.

## TABLE 5-5

## Application of Fuel Cells to Pipelines

| | Gas Turbine + Centrif. Compress. | Recipr. Gas Engine + Recipr. Compress. | $H_3PO_4$ Fuel Cell, DC Motor + Centrif. Compress. | Molt. $CO_3^=$ Fuel Cell, DC Motor + Centrif. Compress. | Molt. $CO_3^=$ Fuel Cell, Inverter, AC Motor + Cen. Comp. | AC Motor on Utility Grid + Centrif. Compress. |
|---|---|---|---|---|---|---|
| **Efficiencies, % (LHV)** | | | | | | |
| Prime Mover (LHV) | 34 | 39 | 41 | 50 | 50 | -- |
| Inverter | | | | | 96 | |
| Compressor | 80 | 80 | 80 | 80 | 80 | 80 |
| Motor | | | 95 | 95 | 95 | 95 |
| Gears | | | 98 | 98 | | |
| HP Required-Prime Mover | 6250 | 6250 | 6715 | 6715 | 6850 | 6250 |
| No. of Units | 1 | 1 | 1 F.C.<br>3 Mot/Comp | 1 F.C.<br>3 Mot/Comp | 1 F.C.<br>3 Mot/Comp | 3 Mot/Comp |
| Investment, $M | 2.93 | 4.04 | 4.53 | 4.33 | 4.34 | 2.11 |
| **Annual Costs, $M/yr** | | | | | | |
| Capital Charges | 0.59 | 0.81 | 0.91 | 0.86 | 0.87 | 0.42 |
| Maintenance & Operation | 0.25 | 0.40 | 0.40 | 0.40 | 0.33 | 0.24 |
| Energy | 2.17 | 1.89 | 1.93 | 1.58 | 1.62 | 1.98 |
| TOTAL | 3.01 | 3.10 | 3.24 | 2.84 | 2.82 | 2.64 |

The results of the various cases developed are presented in Table 5-5. It will be seen that the base cases--the gas turbine and the reciprocating gas engine--are both superior to the $H_3PO_4$ fuel cell case in investment and in total annual costs. The cases for the molten carbonate fuel cell are slightly better than the base cases in annual costs, although the investments for the fuel cell cases are 7% higher than for the gas engine and about 50% higher than for the gas turbine. There is little difference between the two molten carbonate fuel cell cases; it was thought that the use of AC motors, which are only 40% of the cost of DC motors plus the speed increasing gears required, would result in a lower capital cost, but the cost of the inverter required in the AC case together with the efficiency loss associated with the inverter offset this cost advantage.

The lowest annual cost case, however, and the one with the lowest investment, is that based on using AC motors taking power from utility grids. This is based on utility power costing 5.1¢/kWhr compared to SNG cost of $5.90/k SCF. The costs of these two forms of energy will have to be compared in the future to ascertain whether the resulting differences in annual pipeline compression costs maintain their relative positions.

Consideration was given to possibilities for improvement in performance of the base case combustion turbine and the gas engine through incorporation of advanced technology. Simple-cycle gas turbine efficiencies of up to 37% have been predicted based on higher inlet gas temperatures, probably with some kind of blade cooling. Efficiencies of over 40% are possible with combined cycles, but such equipment is not feasible at the small capacity levels being considered in this study. Efficiencies with regenerative cycle turbines are probably limited to about 35-36%(5-1). Assuming that 37% efficiency can be obtained with a simple-cycle machine in this size range, without significant increase in capital investment per horsepower, the total annual costs on the same bases as the other cases in Table 5-5 would be $2.9 million, about a stand-off with the molten carbonate fuel cell case. For a reciprocating gas engine of the capacities being considered, the incorporation of an organic bottoming cycle does seem feasible.(5-1) This could increase the overall efficiency of the system to 45% with little increase in capital cost per horsepower; this would also result in total annual costs of $2.9 million.

It is also possible to improve the efficiencies of the fuel cells through design modification, at some penalty in capital cost. This can be accomplished by incorporating additional electrode surface in the fuel cells, thus reducing current density and increasing efficiency. About 10% improvement in efficiency (4 to 5 percentage points) might be achieved on a cost-effective basis. Even a 10% improvement in the molten carbonate fuel cell cases, however, would not reduce the total annual costs for those cases below the total costs for the operation of AC motors on utility grid power.

The results of this study indicate no advantage for $H_3PO_4$ electrolyte fuel cells for pipeline applications, and only a small advantage for molten carbonate fuel cells as compared to the base case gas turbines and gas engines. On the other hand, advanced gas turbines and gas engines may overcome most of this indicated advantage for the molten carbonate fuel cells.

Fuel cells do have a significant advantage over gas turbines in fuel efficiency at part load. In a gas transmission system in which throughput is increasing with time, the use of fuel cells would have an advantage over gas turbines if the equipment was required to operate at reduced capacity while line throughput was building up. Generally, however, this situation is handled by adding compression capacity in increments and running all units at maximum capacity.

A 25% reduction in investment would be required for the annual operating cost for a fuel cell system to be breakeven with an electric motor drive.

If fuel cells are developed and commercialized for other applications, their potential for use in pipeline services should be considered later when better information on costs and efficiencies become available. It is not expected that molten carbonate fuel cells will be available commercially before 1990. Presumably, these conclusions will be firmed up by the contracted study on applications of fuel cells to pipeline operations, being made for the Department of Energy.

## 5.4 Overall Energy Efficiency

One factor to be considered in selecting the prime mover and fuels that may be used in the future is the amount of basic resource required to produce a certain amount of work, either pumping liquids or compressing a gas. The efficiencies of the various prime movers were established in the preliminary screening and the amount of resource needed to produce a BTU of fuel at the engine. In this section the two different efficiencies are combined in terms of the thousands of gross BTU of primary fuel (e.g. coal, shale, biomass, etc.) required to produce one horsepower (2544 BTU of work energy), taking into account all the energy lost in conversion to engine fuel, lost in transportation to the engine, and lost as reject heat at the engine itself.

The figures were calculated using the following expression:

$$\underset{\text{(Mine to Shaft)}}{\text{BTU/HPh}} = \frac{2544}{E} \times F_1 \times F_2$$

$E$ = Engine efficiency in net BTU expressed as a fraction, e.g. .375 for diesel engines.

$F_1$ = A factor relating the gross BTU of the engine fuel to its net BTU content. This is a function of the hydrogen content of the fuel and ranges from 1.18 for hydrogen to 1.02 for coal.

$F_2$ = A factor relating the gross BTU content of the primary fuel at source to the gross BTU content of the resultant engine fuel delivered to the customer's tank, e.g. 1.82 BTU of coal at the mine are needed to produce 1.00 BTU of coal liquid at the engine. These factors are given in Section 3.2.3.3.

The engine efficiencies used are generally the mid-point figures of the ranges shown in Table 3-20, viz:

| Engine | Efficiency E |
|---|---|
| Diesel | 0.375 |
| Gas Turbine - Conv. | 0.275 |
| - Adv. | 0.34 |
| Otto | 0.28 |
| Stratified Charge | 0.30 |
| Electric Motor | 0.95 |
| Recip. Gas Engine with Methane | 0.39 |
| Combined Cycle for gas turbine/steam or diesel/bottom Rankine | 0.42 |

The factors for the fuels are:

|  | $F_1$ (gross/net) | $F_2$ (mine BTU/fuel BTU) |
|---|---|---|
| Raw Shale | 1.065 | 1.11 |
| Refined Shale | 1.068 | 1.59 |
| Coal Liquids | 1.055* | 1.82 |
| Methane | 1.125 | 1.85 |
| Methanol | 1.130 | 1.92 |
| Electricity | 1.000 | 2.89 |

*1.080 for coal derived gasoline.

For fuels having heat content in the range 18,000 BTU/lb, factor $F_1$ is approximately 1 + 0.5 (percent $H_2$ ÷ 100). For other fuels, $F_1$ was derived from tables of net and gross heat content.

The mine-to-shaft efficiency for the prime mover/fuel combinations are shown in Table 5-6.

The combined cycle with a steam turbine is included in the tabulation, even though such equipment may not be economically feasible at the capacity levels being considered in this study. This will illustrate the potential for this type of prime mover, from an energy conservation standpoint.

The relative ranking of the various fuels by resource base and type of prime mover is shown in Table 5-7. The most energy efficiency prime mover/fuel combination is the electric motor, using coal to produce the electricity. Nuclear power could also be used to generate the electricity but the efficiency would be on a different basis. Since the electric motor is also the most economical, this particular prime mover-energy combination would appear to be the prime choice for future pipeline use, except in cases where it is not feasible to run electric power lines, such as offshore production platforms.

## TABLE 5-6

## Mine-to-Shaft Efficiencies for Possible Pipeline Fuels/Prime Movers

k BTU/HPh

| | | Gas Turbines | | Otto Cycles | Combined Cycle | | Fuel Cell | |
|---|---|---|---|---|---|---|---|---|
| Fuel | Diesel | Conv. | Adv. | Strat. | Steam(2) | Electric Motor | $H_3PO_4$ | Molt. $CO_3^=$ |
| Refined Shale | 11.5 | 15.7 | 12.7 | 14.4 | 10.3 | | | |
| Coal Distillate | 13.0 | 17.8 | 14.4 | 16.3 | 11.6 | | | |
| Raw Shale Oil | 8.0 | 10.9 | 8.8 | -- | 7.2 | | | |
| Shale Gasoline | -- | 15.9 | 12.9 | -- | 10.4 | | | |
| Coal Gasoline | -- | 18.2 | 14.7 | 16.7 | 11.9 | | | |
| Methane (Coal) | 14.1 | 19.2 | 15.6 | 13.6(1) | 12.6 | | 13.9 | 11.3 |
| Methanol (Coal) | -- | 20.1 | 16.2 | 19.7 | 13.1 | | | |
| Electricity | -- | -- | -- | -- | -- | 7.8 | | |

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(1) Recip. gas engine.
(2) Included even though currently impractical in pipeline prime mover size range.

## TABLE 5-7

## Ranking of Prime Mover/Fuel Combination for Pipeline Application - Overall Mine-to-Shaft Energy Efficiency Basis

| Resource | Fuel | Prime Mover | Mine-to-Shaft Efficiency, k BTU/Hph |
|---|---|---|---|
| Coal | Electricity | Electric Motor | 7.8 |
| Shale | Raw Shale Oil | Diesel | 8.0 |
| Shale | Raw Shale Oil | Adv. Gas Turbine | 8.8 |
| Coal | Methane | Molt. $CO_3^=$ Fuel Cell | 11.3 |
| Shale | Refined Shale Oil | Diesel | 11.5 |
| Shale | Shale Oil Products | Adv. Gas Turbine | 12.7 |
| Coal | Coal Distillate | Diesel | 13.0 |
| Coal | Methane | Recip. Gas Engine | 13.6 |
| Coal | Methane | $H_3PO_4$ Fuel Cell | 13.9 |
| Coal | Distillate | Gas Turbine | 14.4 |

The next most energy efficient prime mover/fuel combination is using raw shale oil in a diesel or advanced gas turbine. It is questionable if raw shale oil could be used in a diesel, but research in this area may indicate if the problems could be overcome. Also logistical problems would probably limit the potential for using raw shale oil. Some upgrading or use of additives would be required to be able to pump the material.

The use of methane (coal resource base) in a molten carbonate fuel cell would rank next, but as pointed out in the economics section, would not be as economical as the electric motor case.

## 5.5 Fuels/Prime Movers of Possible Future Interest

### 5.5.1 Liquid Pipelines

The three basic types of prime movers that will probably be used in the future are electric motor, advanced gas turbines, and diesel engines. A simple ranking system, shown in Table 5-8, was used to arrive at the relative ranking of these three prime movers. As expected, the electric motor is the most attractive of the three prime movers and is likely to be used in almost all future applications involving liquid pipelines, except in locations where providing electric power to a site is very expensive.

The choice between gas turbine and diesel is very close. Gas turbines would probably be selected, since it would be easier to use the liquid being pumped in a gas turbine than a diesel. While a gas turbine is more critical on fuel requirements from a "cleanliness" standpoint, it is less sensitive than a diesel engine on fuel composition. The possible fuels that may be used would be raw shale oil liquids, shale distillates, coal liquids and alcohols. However, as pointed out in this study, it is unlikely that it will be economical to use these liquids as fuels, compared to electricity for an electric motor.

The third choice on type of prime mover would be the diesel, with shale or upgraded coal liquids as fuels.

Thus, the future fuels and prime movers for liquid pipelines are as follows.

| | Prime Mover | Fuel |
|---|---|---|
| Major User | Electric Motor | Electricity from coal fired power plant |
| Very Limited Use | Advanced Gas Turbine | Raw Shale Oil<br>Shale Oil Liquids<br>Coal Liquids<br>Alcohols |
| Even More Limited Use | Diesel | Shale Oil Liquids<br>Upgraded Coal Liquids |

## TABLE 5-8

### Relative Ranking of Future Liquid Pipeline Prime Movers

| | Electric Motor | Diesel | Advanced Gas Turbines |
|---|---|---|---|
| Initial Installment Cost | 1 | 3 | 2 |
| Maintenance Cost | 1 | 3 | 2 |
| Energy Cost | 3 | 1 | 2 |
| Total Annual Cost | 1 | 3 | 2 |
| Overall Energy Efficiency | 1 | 2 | 3 |
| Proven Reliability | 1 | 3 | 2 |
| Total Overall | 8 | 15 | 13 |
| Total Using Annual Energy Cost Plus Last Two Factors | 3 | 8 | 7 |

## TABLE 5-9

## Relative Ranking of Future Gas Pipeline Prime Movers

| | Electric Motor | Reciprocating Gas Engine | Advanced Gas Turbine |
|---|---|---|---|
| Initial Cost | 1 | 3 | 2 |
| Maintenance Cost | 1 | 3 | 1 |
| Energy Cost | 2 | 1 | 3 |
| Total Annual Cost | 1 | 2 | 2 |
| Overall Energy Efficiency | 1 | 2 | 3 |
| Proven Reliability | 1 | 1 | 1 |
| Total Overall | 7 | 12 | 12 |
| Total Using Annual Energy Cost Plus Last Two Factors | 3 | 5 | 6 |

### 5.5.2 Gas Pipelines

The three basic types of prime movers that will probably be used in the future are electric motors, reciprocating gas engines, and gas turbines. A simple ranking system, shown in Table 5-9, illustrates the relative rankings for these three systems. Clearly the electric motor is the choice for all locations where it is possible to bring power to the site. Where it is not possible to use an electric motor driver, either an advanced gas turbine or reciprocating engine will be used. The gas turbine probably would be selected, simply because it has greater flexibility in handling different types of gases. In the case of methane, the choice would be a toss-up.

The types of fuels that may be used in gas turbines would be the gases being compressed, such as low or medium BTU gases, or methane. However, in the case of methane it would be more economical and energy efficient to use electric motor drivers.

Fuel cells may have a potential in the long term (2000+) if the cost can be reduced by at least 25% relative to electric motor drivers.

## 5.6 Possible R&D Ideas

Since the most likely prime mover to be used for future pipelines is the electric motor, the amount of R&D for alternate fuels is fairly limited. From the pipeline companies viewpoint, the more important future issues they will be facing are possible regulatory constraints and pipeline construction technology for extreme environments.

Some possible areas where R&D may be useful are as follows:

- Continue to make improvements in existing gas turbine drives to increase the efficiency of the current engines, e.g. regeneration, bottoming cycles, etc.
- Investigate ways to incorporate bottoming cycles in to the current reciprocating gas engines.
- Determine if raw shale oil liquids can be used in the types of diesel engines used in pipeline service.
- Follow the R&D activity in molten carbonate fuel cells. If major cost reductions take place, relative to the cost of electric motors, this type of fuel cell may look attractive longer range in gas pipeline service.
- It may be worthwhile to make a planning study to investigate a coal-fired, cogeneration station for a very large pumping station. It would appear that electric power generated from a large coal fired plant would be more attractive.

# APPENDIX 5-A

## DATA AND CALCULATIONS

## Economic Comparison of Fuel Cells with Conventional Prime Movers in Gas Pipeline Operations

### Bases for Economic Comparisons

The costs involved for various types of conventional pipeline stations were calculated from a series of relationships provided by Exxon Pipeline Company, which are given in Table 5-A-1. These relationships were developed by Exxon Pipeline from literature references. The investment costs calculated from these relationships include prime mover, compressor, controls, piping and land required, but do not include the items listed under IV-G in the Table.

The cost and performance information for fuel cells were obtained through telephone conversations with a representative of United Technologies Corporation (UTC). These data are summarized in Table 5-A-2.

### Assumptions

- The Pipeline Horsepower (PHP) required for compressing the gas at each station is constant at 5000 HP.
- 80% efficiency for both centrifugal and reciprocating compressors.
- All costs are in 1980 dollars. A 7%/yr inflation rate was used to adjust costs to 1980 from other years.
- 20% capitalization rate on investments.
- Operating hours/total hours per year (T) = 0.9.

### Case I - Gas Turbine with Centrifugal Compressor

$$\text{Turbine HP required} = \frac{PHP}{E_p} = \frac{5000}{0.8} = 6250\ \text{HP}$$

#### Investment

Investment = 300k$ + 200k$/unit + $300/HP (I-B-3, Table 2-A-1)

Assume single turbine-compressor unit

Then investment = 300k$ + 200k$ + $300 x 6250 = $2.38M (1977 $)
= $2.93M (1980 $)

Note: This formula is based on currently available combustion turbines of about 30% efficiency at full load based on 1000 Btu/SCF gas. Since the SNG being considered in this study has a lower heating value (LHV) of 870 Btu/SCF (Section 7, Task II report), the corresponding efficiency of this turbine is 34% on a LHV basis.

Capital Charges

At 20%/yr capitalization rate,

Capital charges = \$2.93M x 0.20 = 585k\$/yr (1980 \$)

Maintenance Costs

$= 20\text{k\$} + 10\text{k\$/unit} + (30 \times \text{HP})T^{0.5}$ (II-B-2, Table 5-A-1)

$= 30\text{k\$} + (30 \times 6250)0.95 = 208\text{k\$/yr}$ (1977 \$)
$= 255\text{k\$/yr}$ (1980 \$)

Fuel Costs

$= \frac{\text{PHP}}{4.5}$ (gas cost, ¢/kSCF) $\frac{T}{E_p \times E_e}$ (III-C, Table 5-A-1)

SNG cost = \$6.00/M Btu at point of manufacture.

LHV of SNG = 870 Btu/SCF

Therefore, cost of SNG = \$5.22/kSCF (LHV) at point of manufacture. Assume \$5.90/kSCF (LHV) to allow some cost of transmission to average compression station.

Fuel Cost $= \frac{5000}{4.5} \times 590 \times \frac{0.90}{0.80 \times 0.34}$ = \$2.17M/yr (1980 \$)

Total Costs

= \$0.585M + \$0.255M + \$2.17M = \$3.01M/yr (1980 \$)

Case II - Reciprocating Gas Engine with Reciprocating Compressor

Turbine HP required $= \frac{\text{PHP}}{E_p} = \frac{5000}{0.8} = 6250$ HP

Investment

= 300k\$ + 175k\$/unit + \$450/HP (I-B-4, Table 5-A-1)

Assume single engine-compressor unit

= 300k\$ + 175k\$ + \$450 x 6250 = \$3.29M (1977 \$)
= \$4.04M (1980 \$)

Capital Charges

At 20%/yr capitalization rate,

Capital charges = \$4.26M x 0.20 = 810k\$/yr (1980 \$)

Maintenance Costs

$= 20k\$ + 5k\$/unit + (50 \times HP)T^{0.5}$ (II-B-3, Table 5-A-1)

$= 20k\$ + 5k\$ + 300k\$ = 325k\$/yr$ (1977 \$)
$= 400k\$/yr$ (1980 \$)

Fuel Costs (III-C, Table 5-A-1)

$$= \frac{PHP}{4.5}\ (¢/kSCF)\ \frac{T}{E_p \times E_e}$$ Take $E_e = 39\%_{LHV}$ (Ref. 5-1)

$$= \frac{5000}{4.5} \times 590 \times \frac{0.9}{0.8 \times 0.39} = \$1.89M/yr \text{ (1980 \$)}$$

Total Costs

= \$0.81M + \$0.40M + \$1.89M = \$3.10M/yr (1980 \$)

## Case III - Phosphoric Acid Electrolyte Fuel Cell with DC-Motor-Driven Centrifugal Compressor

Investment

Fuel Cell

Investment = \$300/HP (1980 \$) (Table 5-A-2)

DC Motors, Gears and Centrifugal Compressors

For AC motors (3600 RPM) + centrifugal compressors

Investment = 250k\$ + 125k\$/unit + \$175/HP (1977 \$) (I-B-1, Table 5-A-1)
= 308k\$ + 154k\$/unit + \$215/HP (1980 \$)

AC motors (1750 HP, 3600 RPM) cost \$25/HP (1978 \$)*
Efficiency = 95%

DC motors (1750 HP, 850 RPM) cost \$57/HP (1978 \$)*
Efficiency = 95%

Speed increasers (850 to 3600 RPM) cost \$9/HP (1978 \$)**
Efficiency = 98%

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*Information obtained from Louis Allis representative, June 1978.
**Information obtained from Lufkin Gear Co. representative, June 1978.

Increase in cost for DC motors + speed increasers vs AC 3600 RPM motors

$$= (\$57 + 9) - \$25 = \$41/HP\ (1978\ \$)$$
$$= \$47/HP\ (1980\ \$)$$

Assume 3 units for station (DC motors not normally available above around 2000 HP; also, multiplicity of units desirable for station reliability).

Horsepower required for motors

$$= \frac{PHP}{E_g \times E_p} = \frac{5000}{0.98 \times 0.8} = 6380\ HP$$

Total investment for DC motors, speed increasers and compressors, allowing some extra costs for installation over that required for AC motors

$$= 320k\$ + \$170/unit + \$265/HP$$
$$= 320k\$ + 510k\$ + \$265 \times 6380 = \$2.52M\ (1980\ \$)$$

Horsepower required for fuel cell

$$= \frac{PHP}{E_g \times E_p \times E_m} = \frac{5000}{0.98 \times 0.8 \times 0.95} = 6715\ HP$$

Fuel Cell investment = \$300/HP = \$300 x 6715 = \$2.01M (1980 \$)

Total Investment = \$2.52M + \$2.01M = \$4.53M (1980 \$)

Capital Charges

At 20%/yr capitalization rate

Capital charges = \$4.53M x 0.20 = 906k\$/yr (1980 \$)

Maintenance Costs

Fuel Cell

Total operating and maintenance costs = 0.18¢/HPhr (1980 \$) (Table 5-A-2)

$HPhr/yr = 6715 \times 8760 \times 0.9 = 52.9 \times 10^6$

Maintenance costs $= 52.9 \times 10^6 \times \frac{0.18}{100} = 100k\$/yr$ (1980 \$)

DC Motors, Gears and Compressors

For AC motors and compressors

$= 15k\$ + (10 \times HP)(1 + 2T)$ (II-B-1, Table 5-A-1)

$= 15k\$ + (10 \times 6380)(2.8) = 195k\$/yr$ (1977 \$)

$= \$240/yr$ (1980 \$)

But maintenance of DC motors and gears would be somewhat greater; assume 300k\$/yr total.

**Total**

= 300k\$ + 100k\$ = 400k\$ (1980 \$)

**Fuel Costs**

$$= \frac{PHP}{4.5} (¢/kSCF) \frac{T}{E_p \times E_e \times E_m \times E_g}$$ (Based on III-C, Table 5-A-1)

$E_e$ (fuel cell efficiency) = 41% from Table 5-A-2

$$= \frac{5000}{4.5} \times 590 \times \frac{0.9}{0.8 \times 0.41 \times 0.95 \times 0.98}$$

= \$1.93M/yr (1980 \$)

**Total Costs**

= \$0.91M + \$0.40M + \$1.93M = \$3.24M (1980 \$)

## Case IV - Molten Carbonate Electrolyte Fuel Cell with DC-Motor-Driven Centrifugal Compressor

**Investment**

Horsepower requirements for fuel cell and motors same as in Case III: 6715 and 6380.

**Fuel Cell**

Investment = \$270/HP (1980 \$) (Table 5-A-2)
= \$270 x 6715 = \$1.81M

**DC Motors, Gears and Compressors**

Same as for Case III; \$2.52M (1980 \$).

**Total Investment** = \$1.81M + \$2.52M = \$4.33M (1980 \$)

**Capital Charges**

At 20%/yr capitalization rate

Capital charges = \$4.33M x 0.20 = \$0.86M/yr (1980 \$)

**Maintenance Costs**

Same as for Case III: 400k\$/yr (1980 \$)

**Fuel Costs**

$$= \frac{PHP}{4.5} (¢/kSCF) \frac{T}{E_p \times E_e \times E_m \times E_g}$$ (Based on III-C, Table 5-A-1)

$E_e$ (fuel cell efficiency) = 50% from Table 5-A-2.

$$= \frac{5000}{4.5} (590) \frac{0.9}{0.8 \times 0.50 \times 0.95 \times 0.98}$$

= \$1.58M/yr

Total Costs

= \$0.86M + \$0.40M + \$1.58M = \$2.84M/yr (1980 \$)

## Case V - Molten Carbonate Electrolyte Fuel Cell Including Inverter with AC-Motor-Driven Centrifugal Compressor

Horsepower required for fuel cell

$$= \frac{PHP}{E_i \times E_m \times E_p} = \frac{5000}{0.96 \times 0.95 \times 0.8} = 6850 \text{ HP}$$ ($E_i$ = 96% Ref. 5-3)

Horsepower required for motors

$$= \frac{PHP}{E_p} = \frac{5000}{0.8} = 6250 \text{ HP}$$

Investment

Fuel Cell

Cost ex inverter = \$270/HP (1980 \$) (Table 5-A-2)

Inverter Cost = \$60/kW (1977 \$) (Ref. 5-3)
= \$55/HP (1980 \$)

Therefore, investment for fuel cell plus inverter = \$325/HP (1980 \$).

Fuel cell investment = \$325 x 6850 = \$2.23M (1980 \$)

AC Motors and Compressors

= 250k\$ + 125k\$/unit + \$175/HP (I-B-1, Table 5-A-1)

= 250k\$ + 375k\$ + \$175 x 6250 = \$1.72M (1977 \$)
= \$2.11M (1980 \$)

Total Investment = \$2.33M + \$2.11M = \$4.34M (1980 \$)

Capital Charges

At 20%/yr capitalization rate

Capital charges = \$4.34M x 0.20 = \$0.87M/yr (1980 \$)

## Maintenance Costs

### Fuel Cell

Total operating and maintenance costs = 0.18¢/HPhr (1980 \$)
(Table 5-A-2)

$$\text{HPhr/yr} = 6850 \times 8760 \times 0.9 = 54 \times 10^6$$

$$\text{Maintenance costs} = 54 \times 10^6 \times \frac{0.18}{100} = 100\text{k\$/yr (1980 \$)}$$

### AC Motors and Compressors

$= 15\text{k\$} + (\$10 \times \text{HP})(1 + 2T)$ (II-B-1, Table 5-A-1)
$= 15\text{k\$}\ (\$10 \times 6250)(2.8) = 190\text{k\$/yr}$ (1977 \$)
$= 235\text{k\$/yr}$ (1980 \$)

### Total

$= 100\text{k\$} + 235\text{k\$} = 335\text{k\$/yr}$ (1980 \$)

## Fuel Costs

$$= \frac{PHP}{4.5}\ (\text{¢/kSCF})\ \frac{T}{E_e \times E_i \times E_m \times E_p}$$ (Based on III-C, Table 5-A-1)

$$= \frac{5000}{4.5}\ (590)\ \frac{0.9}{0.50 \times 0.96 \times 0.95 \times 0.8} = \$1.62\text{M/yr (1980 \$)}$$

## Total Costs

$= \$0.87\text{M} + \$0.33\text{M} + \$1.62\text{M} = \$2.82\text{M/yr}$ (1980 \$)

## Case VI - AC Motor Operating Off Utility Grid with Centrifugal Compressor

## Compressor

$$\text{Motor horsepower required} = \frac{PHP}{E_p} = \frac{5000}{0.8} = 6250\ \text{HP}\quad (3\ \text{units})$$

## Investment

$= 250\text{k\$} + 125\text{k\$/unit} + \$175/\text{HP}$ (I-B-1, Table 5-A-1)
$= 250\text{k\$} + 375\text{k\$} + \$175 \times 6250 = \$1.72\text{M}$ (1977 \$)
$= \$2.11\text{M}$ (1980 \$)

## Capital Charges

At 20%/yr capitalization rate

Capital Charges = \$2.11M x 0.20 = \$0.42M/yr (1980 \$)

Energy Costs

$$= 69 \times \text{PHP} \ (¢/\text{kWhr}) \ \frac{T}{E_p} \qquad \text{(III-A, Table 5-A-1)}$$

From Table 7-1 of the Task II report, electricity costs including distribution costs are projected to be \$14.9/M Btu in 1980. This is equivalent to 5.1¢/kWhr.

$$\text{Energy costs} = 69 \times 5000 \times 5.1 \ \frac{0.9}{0.8} = \$1.98\text{M/yr (1980 \$)}$$

Total Costs

$$= \$0.42\text{M} + \$0.24\text{M} + \$1.98\text{M} = \$2.64\text{M (1980 \$)}$$

## TABLE 5-A-1

## Pipeline Station Cost Factors

I. Investment Cost

- A. Liquid pumping stations (with centrifugal pumps)
  1. Electric AC motor - 175k$ + 75k$/unit + $100/HP
  2. Electric AC motor with variable output - 175k$ + 125k$/unit + $120/HP
  3. Gas turbine - 225k$ + 150k$/unit + $250/HP
  4. Gas engine - 225k$ + 125k$/unit + $375/HP
- B. Gas compressor stations
  1. Electric AC motor and centrifugal compressor - 250k$ + 125k$/unit + $175/HP
  2. Electric AC motor with variable output and centrifugal compressor - 250k$ + 175k$/unit + $200/HP
  3. Gas turbine and centrifugal compressor - 300k$ + 200k$/unit + $300/HP
  4. Gas engine and reciprocating compressor - 300k$ + 175k$/unit + $450/HP

II. Maintenance Costs (by type of prime mover) ($/yr)

- A. Liquid pumping stations
  1. Electric - 5k$ + ($5 x HP)(1 + 2T)
  2. Gas turbine - 10k$ + 10k$/unit + ($25 x HP) $(T^{0.5})$
  3. Gas engine - 10k$ + 5k$/unit + ($40 x HP) $(T^{0.5})$
- B. Gas compressor stations
  1. Electric - 15k$ + ($10 x HP)(1 + 2T)
  2. Gas turbine - 20k$ + 10k$/unit + (30 x HP)$(T^{0.5})$
  3. Gas engine - 20k$ + 5k$/unit + (50 x HP)$(T^{0.5})$

III. Energy Costs (by type of prime mover) ($/yr)

- A. Electric (constant speed with centrifugal pump or compressor) =

$$(70 \times \text{PHP})\ (¢/\text{kWhr})\ \frac{(T)}{(E_p)}$$

- B. Gas engine / Gas turbine

$$\left.\begin{array}{l}\text{Gas engine}\\ \text{Gas turbine}\end{array}\right\} = \frac{(\text{PHP})}{(4.5)}\ (¢/\text{kSCF})\ \frac{(T)}{(E_p\ E_e)}$$

- C. Liquid fuel

$$\text{Liquid fuel} = \text{PHP} \times 22.3 \times \frac{\$}{\text{M}}\ \text{BTU} \times \frac{(T)}{(E_p\ E_e)}$$

## TABLE 5-A-1 (Cont'd)

IV. Estimating Basis

A. 1977 costs.
B. 500 to 5,000 HP prime mover units.
C. Unattended automated/remote control station operations.
D. Fuel or electric power readily available at customary connection cost.
E. Costs apply to on-land U.S. lower 48 locations.
F. No taxes included.
G. No storage tanks, dehydration equipment, housing or major office structures, or major site improvements.
H. 95% AC motor efficiency and 1,000 BTU/SCF fuel gas.
I. Investments include costs of piping and land.

V. Notations

A. HP = Installed Horsepower
B. PHP = Pipeline horsepower for fluid movement, hydraulic or adiabatic compression
C. $E_p$ = Pump or compressor efficiency (0.70 to 0.85)
D. $E_e$ = Engine or turbine efficiency
E. $E_v$ = AC motor variable drive equipment efficiency,
Variable frequency drive = 0.93
Variable speed coupler = 0.70 @ 3/4 load
= 0.95 @ full load
F. $E_g$ = Gear train efficiency
G. $E_m$ = Motor efficiency
H. $E_i$ = Inverter efficiency
I. T = Time factor, $\frac{\text{operating hours}}{\text{total hours}}$
J. $PHP_{liquids} = 1.7 \times 10^{-5}\, Q\, (Pd - Ps)$
K. $PHP_{gases} = 8.6 \times 10^{-2}\, Q \left(\frac{N}{N-1}\right) Ts\, Zs \left[ \left(\frac{Pd}{Ps}\right)^{\left(\frac{N-1}{N}\right)} - 1 \right]$
L. Q = Flow rate, BPD for liquids, MSCFD for gases
M. Pd = Station discharge pressure, psia
N. Ps = Station suction pressure psia
O. N = Gas specific heat ratio, $\frac{Cp}{Cv}$
P. Ts = Suction temperature, °R
Q. Zs = Compressibility factor @ Ts & Ps
R. k = thousand
S. M = million

## TABLE 5-A-2

## Fuel Cells Costs and Characteristics

| | $H_3PO_4$ Electrolyte | Molt. $CO_3$ Electrolyte |
|---|---|---|
| **Total Erected Cost*** | | |
| $/kW (1977 $) | 325 | 295 |
| $/HP (1980 $) | 300 | 270 |
| **Efficiency, % (LHV)** | | |
| Full Load | 41 | 50 |
| Part Load | 43 | 54 |
| **Maintenance Costs**** | | |
| ¢/kWhr (1977 $) | 0.2 | 0.2 |
| ¢/HPhr (1980 $) | 0.18 | 0.18 |

Based on information obtained from United Technologies Corporation representative, June 1978.

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*Including fuel processor, fuel cells, controls, piping, heat exchangers, dry cooling towers, but not inverters (output is DC power at around 500 volts). Includes $55/kW (1977 $) for installation.

**Includes cost of fuel cell module replacement. No routine operators required; units run unattended with occasional inspection.

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# 6. MARINE

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## 6.1 BACKGROUND

Lloyds Register 1977 (6-1), gives a breakdown of four principal types of world shipping:

- Oil tankers
- Dry bulk carriers
- Container ships
- Other types.

The following figure shows the distribution of vessel size in these various classes of trade.

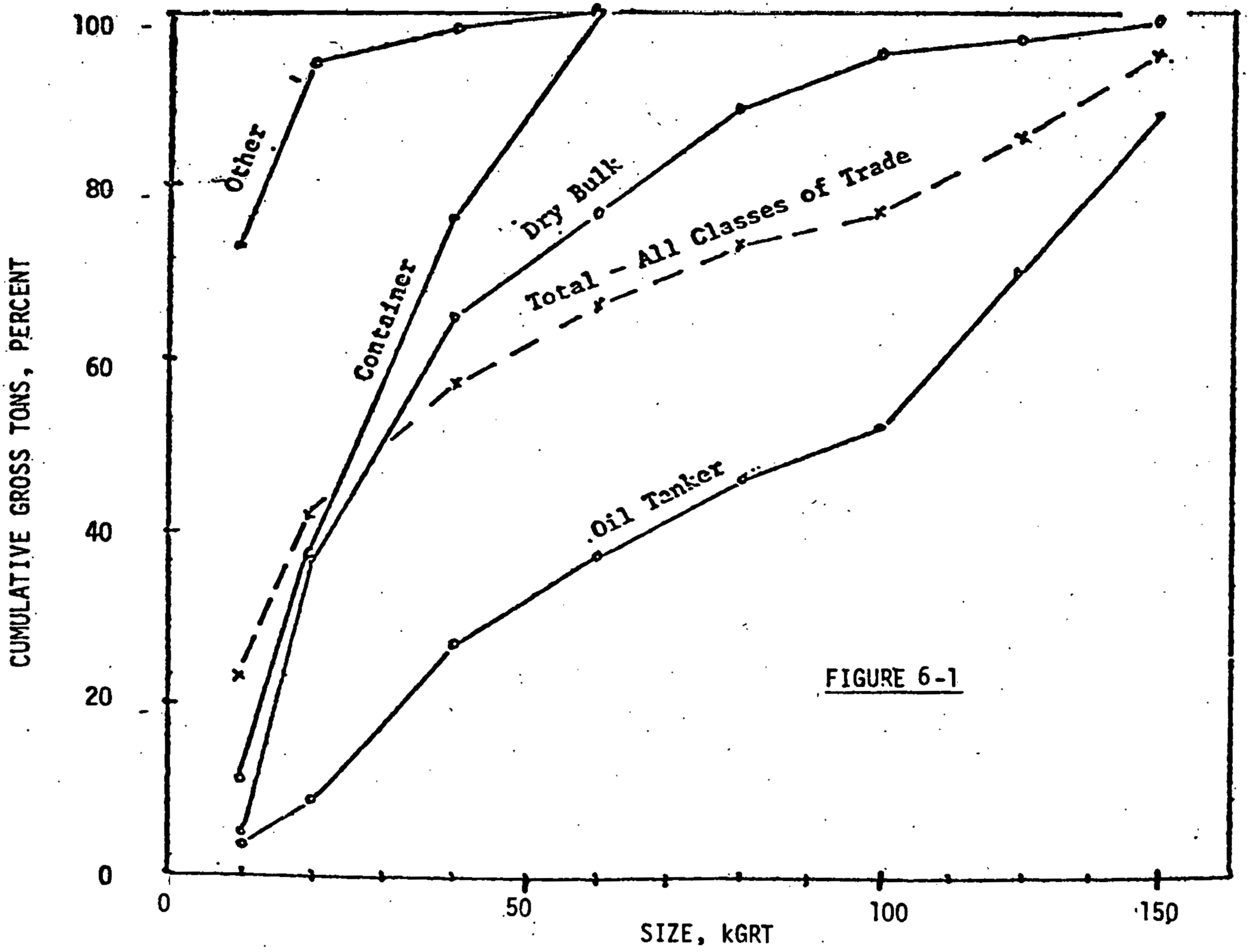

FIGURE 6-1

Most container ships register between 20,000 and 50,000 gross tons.

Oil tankers tend to be larger ships, most ranging from 20,000 to 120,000 tons, with some very large carriers over 250,000 tons to over 500,000 tons.

The horsepower requirements for these various vessels fall within a remarkably narrow range considering the variation in vessel size. A 45 000 HP engine is sufficient to drive the largest oil tanker whereas 10 000 HP is required for the relatively small sized 20,000-ton tanker.

The total installed horsepower in free-world shipping(6-1) is just over 200 million, of which three quarters is currently provided by diesel engines, the rest by steam turbines and a handful of gas turbines.

Some 10 million of the total horsepower are employed for purposes other than propulsion, namely for electric generation, pumps, winches and other auxiliaries. These auxiliaries are almost 100% diesel driven, the fuel in use today being clean petroleum distillate fuel similar to that used in trucks and railroads.

The main propulsion diesel engines are of two types: crosshead engines which are low speed (about 100 RPM two stroke), and trunk engines usually four stroke, averaging 250 RPM.

The low-speed engines are fueled either by bunker fuel oil (defined below) or by blends typically 85% of bunker fuel, 15% of distillate.

The medium-speed engines generally receive a blend which is higher in its proportion of distillate content, ranging from 40% up to 100%. Thus the fuel for the medium-speed engines has tended to cost 15 or 20% more than that used for the slow-speed engines.

Steam turbines are found mostly in larger ships (above 50,000 tons). Bunker fuel oil is currently the universal fuel for steam ships.

Gas turbines are found in some naval vessels, and in a few container ships. Before 1974, they were fueled exclusively with very clean distillate fuel for which special precautions were taken to exclude sodium and vanadium (coming from sea water and bunker fuel contamination, respectively). Since the sharp rise in fuel price in 1974, some of the container ships (but not the naval vessels) have been operated on blends of bunker fuel with distillate. These vessels have endeavored to use fuels similar in quality and cost to those used by diesel engines. However, whereas a simple centrifuge operation suffices to condition such blends for diesel engine operation, an onboard hot water washing technique followed by vanadium inhibition is required for gas turbines.

A recent study(6-6) for the Maritime Administration lists the ship population engaged in foreign trade with the U.S. as shown below.

Vessels in Foreign Trade with U.S.

1974

| | Number | % Fuel Consumed | Energy Utilization BTU/ton Mile |
|---|---|---|---|
| Liners | 1250 | 24 | 1524 |
| Tramp | 2500 | 47 | 1505 |
| Dry Bulk | 500 | 15 | 331 |
| Tanker | 500 | 14 | 219 |

Source: Ref. 6-6

The above data would indicate that about half of the vessels (tramp) would have a load factor around 40-50%, but that at least 30% of the fuel is consumed by vessels with load factors in the 75-90% range (Tanker and Dry Bulk). Since vessels have a long service life, it is necessary to consider the best fuel to use over the life of the vessel. Also, one needs to consider if the "mix" will change in the future. Since the larger size ships have a higher energy utilization factor on a BTU/ton-mile basis, directionally one would expect to see a move towards larger size vessels.

There are two principal fuels, bunker fuel oil and marine diesel oil, used today in world shipping, either separately or in blends. The following table shows typical quality characteristics:

TABLE 6-1

| | Bunker Fuel Oil | Marine Diesel Oil (Distillate Fuel) |
|---|---|---|
| Density, 15°C (60°F) | 0.98 | 0.86 |
| Visc. cs/50°C | 400 | 4 - 8 |
| Redwood/100°F | 3500 | 35 - 45 |
| Sulfur, % | 2 - 4 | 0.3 - 1.3 |
| Ash, % | 0.1 | 0.001 |
| Sodium, ppm | 50 | less than 1 |
| Vanadium, ppm | 80 - 300 | less than 1 |

The next table shows the 1977 free world fleet, its division by engine type and the approximate amount of energy in quads delivered in the form of the two fuels listed above.

TABLE 6-2

1977 World Fleet Installed Horsepower

| Millions of Horsepower | | | Horsepower Supplied by Fuel Type | | |
|---|---|---|---|---|---|
| | | | Bunker F.O. | Blends | Distillate |
| Steam | | 60 | 60 | -- | -- |
| Diesel | Low speed | 115 | 35 | 80 | -- |
| | Med. speed | 33 | -- | 14 | 19 |
| | Auxiliary | 10 | -- | -- | 10 |
| Gas turbine | | negligible | -- | -- | -- |
| Total | | 218 | 95 | 94 | 29 |
| Quads energy per year (Btu x $10^{15}$) | | | 2.2 | 2.1 | 0.6 |

Compared with total U.S.A. energy consumption, of the order 75 quads/year, the free world fleet used 5 quads in 1977.* Only a small percentage of these fuels comes from U.S. sources (about 0.8 quads).

### 6.1.1 CURRENT COSTS OF SHIPPING

Current prices for the 5 quads of energy discussed in the section above, average $2.40/million net Btu (1977 dollars) or $2.77 in 1980 dollars.

The average efficiency of all propulsion engines at sea is 39%(6-2), which means that the fuel cost per horsepower hour produced is:

$$\frac{2547 \times \$2.77}{0.39 \times 10^6} = \$0.018/\text{HPH}$$

It is more convenient to look at the cost per horsepower year. If the ship is at sea for 330 days per year the total number of hours run is 7920, so a horsepower year can be defined as 7920 horsepower hours. Then the fuel cost of the horsepower year is 7920 x $0.018 = $143. This is representative of current fuel costs for a horsepower year. While this represents a high load factor (90%), the impact of different load factors will also be considered.

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* Free world energy consumption was about 180 quads in 1977; marine fuel consumption accounted for 2.7% of this total.

The other cost components are those associated with capital recovery and with the maintenance of the engine and system used, be it steam, diesel, gas turbine or any other kind of prime mover.

Regarding capital, it was necessary to decide how much of the machinery and energy producing auxiliaries should be counted as "engine components." Using Exxon International's system of accounting, a uniform practice was used in this study of including six components with an example given below:

| | Low-Speed Diesel Propulsion (9500 HP)(22,000 T) | |
|---|---|---|
| | $ Million | $/HP |
| Engine | 1.77 | 186 |
| Boiler | 0.42 | 44 |
| Propeller system | 0.18 | 19 |
| Auxiliaries | 1.60 | 168 |
| Electric power | 0.47 | 50 |
| Shipyard installation | 1.40 | 148 |
| Total | 5.84 | 615 |

It will be seen that the diesel engine per se costs $186/horsepower but that its associated machinery, including a boiler to supply heating and a separate diesel generator to supply electricity, plus the cost of installation in the ship, adds up to $615/horsepower.

By putting these capital cost items on the basis of a single horsepower, comparisons can be made between various engines. With suitable scaling factors the comparison can be made even if they are employed in ships of different sizes. If the choice of a different engine obviates the need for certain auxiliaries (for example a steam engine might be able to use a single-boiler system for both propulsion and heating), that advantage can be reflected as a lowering of the total package cost which is more meaningful than the differential cost of the stripped-down engines themselves.

In this report a capital recovery rate of 20% per annum has been used. For the diesel ship example shown that would equate to $123/Hp year.

Maintenance costs of a diesel engine, including lube oil costs are of the order 0.21¢/horsepower hour, so for the 7920 hours of service per year envisaged here (330 days at sea) the maintenance cost would be $17/horsepower year.

Total cost of the horsepower year in 1980 dollars on conventional petroleum fuel would therefore be:

| | $/Horsepower Year (Diesel-9500 HP) |
|---|---|
| Fuel cost (42% eff.) | 133 |
| Capital recovery (20%) | 123 |
| Maintenance | 17 |
| | 273 |

For comparison, corresponding costs in 1980 dollars for a steam turbine system burning bunker fuel oil would be:

| | $/Horsepower Year (Steam-45,000 HP) |
|---|---|
| Fuel cost (32% eff.) | 162 |
| Capital recovery | 81 |
| Maintenance | 12 |
| | 255 |

While this comparison implies that steam is more economical than diesel power, it should be noted that the steam example above is for a much larger ship (45,000 HP - 400,000 tons) than was the case of diesel (9500 HP - 22,000 tons).

The shipping companies have tended to select steam power on the very large ships, and diesel for almost everything else. Steam turbine efficiency falls off in the smaller sizes and the capital costs increases.

The cost associated with a horsepower year in a 22,000 ton steam ship would be about:

| | $/Horsepower Year (Steam-9500 HP) |
|---|---|
| Fuel cost (28% eff.) | 185 |
| Capital recovery* | 112 |
| Maintenance | 16 |
| | 313 |

* Capital components of the turbine itself have been escalated for a size reduction taken to the 0.8 power, and auxiliaries and shipyard installations have been brought up to parity with the diesel ship since they would be common to the two cases.

Gas turbine ships were ordered at a time when fuel was much cheaper than it is today. Their benefits were in terms of speed, compact engine room, minimization of crew and ability to perform maintenance without loss of time at sea.

Today their costs per horsepower year would be estimated as follows, depending upon whether they employ clean distillate fuel, or residual blends with washing and vanadium inhibition.

| | $/Horsepower Year - (Gas Turbine) | |
|---|---|---|
| | Distillate Fuel | Blended Fuel |
| Fuel cost* | 288 | 247 |
| Capital cost | 87 | 89 |
| Maintenance | 12 | 21 |
| | 387 | 357 |

* Note that at the time these vessels were put into service the fuel cost would have been of the order $60/horsepower year and the disparity between the horsepower year costs of these vessels and the alternative diesel powered ship would have been much less, and sufficient to justify the gas turbines for the special services they required. This disparity is likely to increase in the future.

To summarize this introductory section, shipowners are accustomed to the following costs for various classes of vessel.

| | $/Horsepower Year |
|---|---|
| Large steam ships | 250 |
| Diesel ships | 280 |
| Gas turbine ships | 350+ |

This background is provided as a base for the forward look into the ways future non-petroleum fuels may be used.

The attitude of engine builders is that diesel ships will continue to be viable because their efficiency is unsurpassed by any other engine (except the fuel cell), and their engines have a proven capability of operating on the lowest cost petroleum product (which fuel cells do not).

Some believe that the future will see a steady reversion to steam ships, probably with efficiencies improved over today's average (32%), capable of burning coal/oil slurry and eventually coal itself. However, although not a large fraction of total marine horsepower, there is a numerically large portion of the world fleet comprising vessels below 9000 HP.

The diesel engine is ideally suited to these smaller craft and would almost certainly be retained even though the price differential between liquid fuel and coal increased beyond $3/MBtu.

Gas turbine engines available for use at sea, equipped with regenerators, have increased in efficiency from 28% used in the example above, to 34% in the size range 30-40,000 HP. This is above the common steam cycle efficiency so that on certain fuels the large gas turbine ship could be competitive with steam.

However, the steam ship could burn coal which the gas turbine cannot. The interplay of capital, fuel and maintenance costs for several types of engine with different types of fuels is discussed in the next sections.

## 6.2 SUMMARY AND CONCLUSIONS

- For new, large (45,000 Hp) vessels, the most economical and energy efficient prime mover/fuel combination is a steam engine using coal as the fuel.
- Medium size vessels (9500 Hp range) with load factors in the 60-90% range would find diesel more attractive if they can get a liquid fuel for less than $4.50/MBTU. If the liquid fuel cost more than this coal would be more attractive.
- Small size vessels (4500 Hp range) will probably stick with diesel powered engine up to a fuel cost of $5-6/MBTU.
- Diesel engines and regenerative gas turbines would look attractive at a high load factor if a fuel can be obtained for $3/MBTU. The only possible fuel that could fall in this category would be an unrefined shale oil.
- Coal-oil slurry is another possible candidate, especially if a slow speed diesel could be modified to work on a coal-oil slurry. This is especially true for smaller size ships.
- The use of fuel cells does not appear to be attractive for this application.

- The incentive over a coal-steam plant to make coal work in a gas turbine or diesel is insufficient to justify R&D.
- The incentive over coal-steam is also too small to justify R&D on stirling engines in the 10,000 Hp range.
- The incentive is small to improve the efficiency of a marine steam plant burning coal.
- Most current marine prime movers could operate on an unrefined shale oil.
- If $LCH_4$ is available as boil-off, the preferred engine would be a steam fired turbine or a gas turbine. The choice depends on ratio of boiloff to total fuel and size of ship.
- Phase out of liquid fueled ships will be very long; they consume very little of the world's energy, and they consume the lowest grade of petroleum which can be made from poor quality crudes - at small cost.
- Future prime movers used in international marine trade must be able to find usable fuels worldwide.
- For coastal trade vessels, new construction would favor coal-fired steam turbines except for those vessels carrying Alaskan crude. Regenerative gas turbines or combined gas turbine/steam turbine engines would be a possibility on this route.
- Great Lake vessels may also find steam turbines attractive if environmental restrictions would not limit the use of coal. Use of shale oil distillate or Canadian Tar Sand Oil in a diesel is another possibility.
- Tug boats on inland waterways will continue to use medium-to-high speed diesel engines, with distillate from shale oil.
- Pleasure craft propulsion systems will probably develop in a parallel fashion to highway traffic. Fuel possibilities include alcohols and shale or coal derived gasolines.

## 6.3 TOTAL ECONOMICS AS A FUNCTION OF ENGINE TYPE AND FUEL TYPE (NON-PETROLEUM FUELS)

Table 6-3 summarizes the following in combination.

- Cost of engine, its auxiliary components and installation at the shipyard all in 1980 dollars per shaft horsepower at the engine.
- Heat rate in Btu (LHV)/HPH, and efficiency expressed as a percentage taking HPH = 2547 Btu.

## TABLE 6-3

## ECONOMIC FACTORS FOR VARIOUS MARINE ENGINES AND POSSIBLE FUTURE FUELS

| | | | | Gas Turbine | | | | Fuel Cells | |
|---|---|---|---|---|---|---|---|---|---|
| **$/Horsepower** | Steam/Oil | Steam/Coal | Diesel | Simple | Regen. | Stirling | Free Piston | $PO_4$ | $CO_3$ |
| Engine | 86 | 86 | 186 | 75 | 167 | 300 | 200 | 347 | 321 |
| Boiler | 58 | 230 | 44 | 50 | 50 | 50 | 50 | 44 | 44 |
| Propeller | 20 | 20 | 19 | 53 | 53 | 20 | 20 | 19 | 19 |
| Auxiliaries | 148 | 158 | 168 | 125 | 138 | 158 | 158 | 168 | 168 |
| Power supply | 21 | 21 | 50 | 35 | 35 | 35 | 35 | 32 | 32 |
| Shipyard installation | 73 | 100 | 148 | 75 | 100 | 150 | 150 | 167 | 159 |
| Total | 406 | 615 | 615 | 413 | 543 | 713 | 613 | 777 | 743 |
| **Fuel** | | | | | | | | | |
| Btu/HPH | 7990 | 7990 | 6060 | 9250 | 7280 | 7280 | 9258 | 6212 | 5094 |
| % E (LHV) | 32 | 32 | 42 | 28(25) | 35(34) | 35 | 28 | 41 | 50 |
| **Maintenance** | | | | | | | | | |
| ¢/HPH | .15 | .21 | .21 | .15 | .18-.22 | .15 | .50 | 0.17 | 0.17 |
| **Fuel Costs/HPY** | | | | | | | | | |
| ($1.23/MBTU) | -- | 78 | 59 | 90 | -- | 71 | 90 | 61 | 50 |
| ($2.80/MBTU) | 177 | -- | 134 | 205 | -- | 161 | 205 | 138 | 113 |
| ($3.00/MBTU) | 190 | -- | 144 | 220 | (178) | 173 | 220 | 148 | 121 |
| ($4.90/MBTU) | 310 | -- | 235 | 359 | 283 | 283 | 359 | 241 | 198 |
| ($6.30/MBTU) | 398 | -- | 302 | 461 | 364 | 364 | 461 | 310 | 254 |
| ($9.00/MBTU) | 570 | -- | 432 | 659 | 519 | 519 | 659 | 443 | 363 |
| ($9.50/MBTU) | 601 | -- | 456 | 696 | 548 | 548 | 696 | 467 | 383 |

- Maintenance cost in 1980 cents per horsepower hour generated.
- Fuel costs to generate a horsepower year all on the common basis that the engines will run at rated power for 7920 hours/year (330 days at sea).

The sums of the three cost components are given in Table 6-4.

In order of thermal efficiency (E) the engines are:

| | |
|---|---|
| Fuel Cells/DC Motors | |
| Molten carbonate type ($CO_3$) | 50% |
| Phosphate type ($PO_4$) | 41% |
| Diesel | 42% |
| Stirling | 35% |
| Gas turbine regenerative | 34% (35% on clean fuel) |
| Steam* | 32% (28% smaller ships) |
| Gas turbine simple | 28% (25% smaller ships) |
| Free piston | 28% |

* Higher efficiencies are possible but may not be justified if coal is the fuel.

The candidate fuels in order of cost are:

| | $/MBtu (F) |
|---|---|
| Coal | 0.9-1.6 |
| Coal/oil slurry | 2.80+ |
| Raw shale oil | 3-3.5 |
| Shale liquids | 4.7-5.1 |
| Coal liquids | 5.9-9.7 |
| Liquid methane | 9.05-12.55 |

## TABLE 6-4

## ANNUAL OPERATING COST OF VARIOUS PRIME MOVERS - FUEL COMBINATIONS - $/HPY

|  | Steam |  |  | Gas Turbine |  |  |  | Fuel Cells |  |
|---|---|---|---|---|---|---|---|---|---|
| 30 000 HP + | Liquid Fuel | Solid Fuel | L.S. Diesel | Simple | Regen. | Stirling | Free Piston | $PO_4$ | $CO_3$ |
| FUEL COST - $/MBTU |  |  |  |  |  |  |  |  |  |
| ($1.23) |  | 217 | 199 | 189 | 200 |  |  | 184 | 167 |
| ($2.80) | 270 | -- | 274 | 304 | 287 |  |  | 261 | 230 |
| ($3.00) | 283 | -- | 284 | 316 | 298 |  |  | 271 | 238 |
| ($4.90) | 403 | -- | 375 | 448 | 405 |  |  | 364 | 315 |
| ($6.30) | 491 | -- | 442 | 553 | 489 |  |  | 433 | 371 |
| ($9.00) | 663 | -- | 572 | 743 | 642 |  |  | 566 | 480 |
| ($9.20) | 675 | -- | 581 | 757 | 653 |  |  | 576 | 488 |
| ($9.50) | 694 | -- | 596 | 779 | 670 |  |  | 591 | 500 |
| **9000 - 15 000 HP** |  |  |  |  |  |  |  |  |  |
| ($1.23) |  | 266 | 199 | 205 | 209 | 225 | 251 | 229 | 212 |
| ($2.80) | 321 | -- | 274 | 332 | 308 | 316 | 364 | 307 | 275 |
| ($3.00) | 335 | -- | 284 | 348 | 321 | 328 | 379 | 316 | 283 |
| ($4.90) | 472 | -- | 375 | 481 | 419 | 437 | 516 | 410 | 360 |
| ($6.30) | 574 | -- | 442 | 614 | 529 | 518 | 616 | 479 | 416 |
| ($9.00) | 769 | -- | 572 | 798 | 663 | 673 | 811 | 612 | 525 |
| ($9.20) | 784 | -- | 581 | 814 | 675 | 685 | 825 | 621 | 533 |
| ($9.50) | 806 | -- | 596 | 838 | 692 | 702 | 847 | 636 | 545 |
| **4500 HP Ship** |  |  |  |  |  |  |  |  |  |
| ($1.23) |  | 299 | 199 |  |  |  |  |  |  |
| ($2.80) | 354 | -- | 274 |  |  |  |  |  |  |
| ($3.00) | 370 | -- | 284 |  |  |  |  |  |  |
| ($4.90) | 523 | -- | 375 |  |  |  |  |  |  |

Combinations delineated by boxes are considered unlikely to have technical success.

In order of capital investment, engine plus auxiliaries plus shipyards installation, the candidates are:

| | $/Horsepower | |
|---|---|---|
| | Large Ships (30-45,000 HP) | Smaller Ships (9-15,000 HP) |
| Liquid fuel fired steam | 406 | 533 |
| Simple gas turbine | 413 | 443 |
| Gas Turbine - Regenerator | 543 | 573 |
| Free piston | -- | 613 |
| Low-speed diesel | 615 | 615 |
| Fuel cells - phosphate | 549 | 777 |
| molten carbonate | 518 | 743 |
| Coal fired steam | 615 | 804 |

For very small ships (about 4500 HP) the following investments are calculated.

| | $/HP |
|---|---|
| Liquid fired steam | 580 |
| Coal fired steam | 896 |
| Low speed diesel | 615 |

In the case of very small ships the total cost of a horsepower year is less for diesel than for liquid fired steam at practically any fuel cost.

The solid coal fired steam plant becomes viable when liquid fuel for the diesel engine is priced at $2/MBtu above the price of coal.

In order of maintenance costs the various combinations are:

| | $/Horsepower Hour (M) |
|---|---|
| Oil fired steam | 0.0015 |
| Simple gas turbine | 0.0015 |
| Stirling | 0.0015 |
| Fuel cells - $PO_4$ | 0.0017 |
| - $CO_3$ | 0.0017 |

| | |
|---|---|
| Coal fired steam | 0.0021 |
| Diesel | 0.0021* |
| Regenerative gas turbine | 0.0023 |
| Free piston | 0.0050* |

* Substantial lube oil requirements relative to other engines.

The cost of operation of a horsepower unit for one year is given by the expression.

$$\$/HPY = 0.2\ I + 7920\ \left(\frac{F \times 2547}{10^4\ E} + M\right)$$

I = investment, $/HP

F = fuel cost, $/MBtu

E = efficiency, %

M = maintenance, $/HPH

### 6.3.1 COAL-FIRED ENGINES (COAL $0.9-1.6/MBTU)

Clearly any engine which can be made to operate on coal is going to be of interest since coal has the lowest price of the candidate fuels.

In Table 6-5, the cost of a horsepower year is given for each engine in each of two sizes of ship, whether it can burn coal or not. Those which have a low chance of technological success have been enclosed in boxes.

TABLE 6-5

| | $ Cost/HPY with Coal | |
|---|---|---|
| | Large Vessel 30,000 HP+ | Smaller Vessel 9000 - 15,000 HP |
| Coal fired steam | 196-240 | 242-293 |
| Stirling engine | -- | 206-247 |
| Low-speed diesel | $\boxed{183\text{-}216^*}$ | $\boxed{183\text{-}216}$ |
| Gas turbine, simple | $\boxed{159\text{-}210}$ | $\boxed{173\text{-}230}$ |
| , regenerative | $\boxed{180\text{-}222}$ | $\boxed{188\text{-}232}$ |
| Free piston | $\boxed{\text{--}}$ | $\boxed{227\text{-}277}$ |

* Figures in boxes represent combinations of fuel and engines which are not likely to be technically satisfactory.

Even if coal could be burned in a gas turbine, or in a diesel engine, the economic advantages of such combinations over a coal-fired steam plant appear insufficient to justify consideration for the large vessels. This conclusion can be drawn without even asking whether the combination of coal with diesel engines is practicable. For large vessels the coal-fired steam plant represents a relatively small extension of existing well proven technology, namely, the installation of coal-fired boilers in ships.

Such boilers would have twice the height, more than twice the mass and nearly four times the combustion volume of their oil-fired counterparts. Fuel storage for equal range would have to be 50% larger in volume than that of today's oil-fired steamships, but this factor applies to any coal-fired ships, however powered.

An important consideration will be the cost of such boilers and their fuel and ash handling auxiliaries.

On <u>land</u>, a coal-fired boiler costs between 5 and 8 times as much as an oil-fired boiler, including equipment to control sulfur and particulate emissions to low levels.

On the assumption that less pollution control would be necessary at sea, coal-fired boiler costs have been estimated at $40/hourly pound of steam in the large vessels, $53/hourly pound of steam for smaller vessels. These figures compare with $10/hourly pound of steam for oil-fired burners.

One boiler manufacturer has indicated that these cost projections are too severe, and that sea-going coal boilers may be obtained for no more than twice the oil-fired cost. If so, then the cost of the horsepower year for a large coal-fired steamship would fall to $188/HPY.

Smaller steamships would be more expensive to build on a horsepower basis, and would be slightly less efficient. The estimated cost for the horsepower year is $266 at 9500 HP, rising to $299 at 4500 HP. The basis for all capital adjustments and efficiencies is given in Appendix 6-A. Again the supposition has been made that the coal-fired boiler would entail four times the cost of a similarly sized oil-fired boiler. With the lower cost estimate, the cost of the horsepower year would be about $223-$250.

The only practical alternative for a smaller coal-fired vessel would be the Stirling engine, which shows a horsepower year cost of $225. Since such an engine, in the size range of about 10,000 HP would represent an entirely new technological venture, there seems hardly enough advantage over steam to justify even a demonstration. Although there are no firm data on the cost of such a large Stirling engine a figure of $300 per HP for the engine itself has been taken on the basis that Stirling engines must cost more than diesels, for which there is a firm basis of $186/HP.

Even if the chosen Stirling engine cost should be in error by $100, that would reduce the Stirling cost in dollars per horsepower year to $205, not sufficiently below the cost of a steam-driven vessel to generate real interest.

There seems no doubt that if shipbuilding pick-up after 1985 (following its current slowdown due to recession), a coal-fired steam power plant will remake its appearance, in the first place for ships involved in international coal transportation.

### 6.3.2 COAL-OIL SLURRY ($2.80+/MBTU)

The costs per horsepower year for the various engines when fueled by coal-oil slurry are shown in Table 6-6.

TABLE 6-6

| | $ COST/HPY WITH COAL-OIL SLURRY | |
|---|---|---|
| | Large Vessels 30,000 HP + | Smaller Vessels 9000 - 15,000 HP |
| Steam | 270 | 321 |
| Stirling | -- | 364 |
| LS diesel | 274 | 274 |
| Gas turbine-simple | 304 | 332 |
| Gas turbine-regenerative | 287 | 308 |
| Free piston | -- | 364 |

The situation here is similar of the situation on coal-fired boilers. Most engines are unlikely to run on coal slurry without extensive modification and the cost advantages compared with steam seem insufficient to produce any serious contender. The boxes placed round the figures indicate unlikelihood of technological success.

There is one important exception to this general observation, and that is the diesel engine. The diesel engines, currently installed, represent the largest fraction of total horsepower at sea today, and numerically they are an even larger fraction because they are found in ships of many sizes.

Their manufacturers have a vested interest in prolonging their use, and in keeping a place for them as alternate fuels displace petroleum fuels. Accordingly, considerable development work is being done by these manufacturers to make the diesel operate on coal oil slurry, and indeed should this work be successful, such a diesel engine would be competitive with steam fired by coal slurry, provided that the modifications to the diesel engine could be made for less than $235/HP in the 9000-15,000 HP range.

However, for new construction, the competition would not be between slurry-fired diesel and slurry-fired steam, but rather between slurry-fired diesel at $274/HPY and direct coal-fired steam at $242-293/HPY in the smaller ships and $196-240 or less in the large ships.

The gap is sufficiently small to keep the slurry-fired diesel potentially viable in the smaller vessels, but the technology whereby diesels would run on slurry is not yet proven.

### 6.3.3 RAW SHALE OIL ($3-3.5/MBTU)

The corresponding horsepower year costs are shown in Table 6-7:

TABLE 6-7

| | $ COST/HPY WITH RAW SHALE OIL | |
|---|---|---|
| | Large Ships 30,000 HP + | Smaller Ships 9000 - 15,000 HP |
| Steam | 283-315 | 335-372 |
| Diesel | 284-307 | 284-307 |
| Gas turbine simple* | 316-355 | 348-389 |
| Gas turbine regenerative* | 298-326 | 321-339 |
| Stirling | -- | 328-357 |
| Free piston | -- | 379-414 |

* With on-board fuel washing.

All of the prime movers are fairly close in estimated operating cost and thus competitive. Probably all the engines would be able to operate on raw shale oil with very little more on-board treatment than is currently given to bunker fuel oil, viz. centrifuging for diesel, washing for gas turbines.

Among the group, the free piston engine is least economical, being penalized by low efficiency and with maintenance cost higher than that of the diesel engine.

Even if its efficiency were raised to 32% and its maintenance costs reduced to parity with diesel, the cost of the raw shale/free piston horsepower year would still be $340/HPY, easily surpassed by the diesel because of the latter's outstanding efficiency.

With raw shale oil (or some similar liquid fuel) at $3-3.5/MBTU the diesel engine remains in a relatively favorable position particularly for the smaller ships and the regenerative gas turbine becomes a very close contender for the large vessels.

However, from the point of view of international supply, coal would be more likely to be available worldwide. Accordingly, it seems likely that new construction will go towards a coal-fired steam boiler/turbine in the 2000-2010 decade.

## 6.3.4 OTHER FUELS, COAL AND SHALE LIQUIDS AND LIQUID METHANE

With one exception, the other fuels are all technically satisfactory for any of the engines or can be made so with little modification. The quality features which they have, are, in general unnecessary for the engines envisaged, and there is no way to compensate for their high costs by any meaningful increase in efficiency. The exception is the two possible coal liquid candidates.

These candidates could appear in either of two forms:

a. As a high-quality paraffinic liquid from indirect liquifaction (i.e. Fischer Tropsch liquid) with its price a strong function of by-product methane sales.

b. A low quality, raw, unhydrogenated residue such as that appearing in Table 6-22 in the Appendix volume.

Obviously the type (a) would be by far preferable, since it could be used in diesel engines, or gas turbines. The type (b) would have several drawbacks, the first of which is that it might be heavier than sea-water. If so, its use would probably be restricted to boilers.

These higher priced fuels (shale oil distillates and coal liquids) are covered in the following tables (Table 6-8 and 6-9).

TABLE 6-8

$/HPY SHALE DISTILLATE ($4.7-5.1/MBTU)

| | Large Ships | Smaller Ships |
|---|---|---|
| Steam | 391-416 | 458-487 |
| Diesel | 365-384 | 365-384 |
| Gas turbine regenerative | 392-415 | 406-429 |
| Stirling | -- | 426-450 |
| Free piston | -- | 500-529 |

All of these are much above the cost of a coal-fired horsepower year which was $217/HPY for large ships and $266/HPY for smaller vessels.

## TABLE 6-9

### $/HPY COAL LIQUIDS ($5.9-9.7/MBTU)

| | Large Ships | Smaller Ships |
|---|---|---|
| Steam | 467-707 | 544-817 |
| Stirling | -- | 496-716 |
| Diesel | 412-603 | 420-603 |
| Gas turbine regenerative | 448-669 | 474-687 |

If the coal liquid is high in aromatics and of low hydrogen content. i.e. a raw coal-liquid from direct liquifaction, it will be usable as a liquid steam boiler fuel or Stirling engine fuel. It might be usable in low-speed diesel engines, and is likely not to be satisfactory in gas turbines because of its very aromatic nature, which in the extreme case makes the fuel heavier than water and consequently very difficult to clean on board.

There are two conclusions to be drawn:

1. If this were the <u>only</u> fuel available there would be real pressure to make it work in the diesel engine.
2. As long as coal is available, this fuel would not appear to be attractive for new construction, because ships can be fired directly with solid coal for about half the cost per HPY.

With the fuel cost in the $9/MBTU range, the diesel engine is clearly the best, but the horsepower year cost is twice that of a coal-fired ship.

The annual operating cost for various prime movers using liquid methane are shown in Table 6-10.

## TABLE 6-10

### $/HPY LIQUID METHANE ($9.05-12.55/MBTU)

| | Large Ships | Smaller Ships |
|---|---|---|
| Steam | 666-888 | 771-1022 |
| Diesel (spark ignited) | 572-740 | 572-740 |
| Gas turbine regenerative | 633-827 | 650-847 |
| Stirling | -- | 679-881 |
| Free piston | -- | 813-1065 |

If liquid methane were the only fuel available, the gas turbine might have slightly more advantage than this table indicates. In the table, it has been assumed that a diesel engine, converted to run on high octane methane, would retain its "sea-going efficiency" of 42%. If, in fact, this necessitated a change to an Otto cycle engine at 13:1 compression ratio, the efficiency might fall to 38 or 39% and the cost of the horsepower year from the modified engine would then increase and bring it very close to the gas turbine alternative.

A special case arises when it is contemplated to use methane boil-off as engine fuel on an LNG tanker. To the extent that boil-off must be tolerated, that fuel can be considered to be free, and the choice of engine would be that which combines low investment with reasonable maintenance, namely steam (gas fired) or a gas turbine. However, methane is not always available as free boil-off.

1. If the boil-off is not enough to sustain the ship on her total cargo-carrying journey, she must either use a second fuel or dip into her cargo (valued at \$9.05-12.55/MBTU) for the balance.
2. When she travels in ballast, she must either keep some methane aboard for engine use (again \$9.05-12.55/MBTU) or use a second fuel.

Obviously the ratio of the boil-off to total fuel required affects the choice of engine. For the very large ships involved in this trade, steam boilers fired by methane and/or by raw shale oil would be the most economical.

In medium-sized ships, a regenerative gas turbine fired with the same two fuels could be the most economical.

## 6.4 SENSITIVITY OF FINDINGS

With the candidate fuels under discussion at the prices which were developed in this study, coal, fired directly in steamships is a clear winner for large ships, while for smaller ships the diesel engine is close to parity with coal-fired steam if it can be operated on coal/oil slurry, or if it can obtain a fuel at \$3-3.50/MBTU, such as raw shale oil. These conclusions are for a high load factor and an assumed capital recovery factor as well as the assumed fuel cost. All of these factors are considered as sensitivities below.

### 6.4.1 COAL PRICE

If coal were to double in price, but raw shale oil to remain at \$3.00, for example, the following costs would apply to the combinations under discussion:

TABLE 6-11

| | Large Ships | Smaller Ships | Smallest Ships |
|---|---|---|---|
| Coal ($2.46/MBtu) steam | 295 | 355 | 403 |
| Coal-oil slurry ($3.30/MBtu) | | | |
| steam | 301 | 356 | 394 |
| diesel | 298 | 298 | 298 |
| Raw shale ($3/MBtu) | | | |
| steam | 283 | 335 | 370 |
| diesel | 284 | 284 | 284 |
| G.T.-Reg. | 298 | 321 | -- |

Such a change in the relative price of solid coal and raw shale oil (i.e. a doubling of the coal price) puts the diesel or gas turbine ship close to parity with steam for large vessels, and they are even better for smaller ships. For the smallest ships, diesel would be attractive against coal fired steam even if the price of liquid fuel rose to $5.50/MBTU.

Thus the ratio of coal price to "lowest grade diesel fuel price" is of major importance to the competitive position of the coal fired steamship. Also it affects the length of economic life left to the diesel engine.

Raw shale oil appears to be the only source of "lowest grade diesel fuel", which might take the place of today's ships' fuel, namely bunker fuel oil derived from petroleum.

It appears that a liquid fuel, suitable for diesel engines cannot be made from coal at a price much less than $9/MBtu, certainly not for less than $6/MBtu.

Under that situation, if shale oil is not developed, future ships will be coal-fired steam ships and the diesel powered fleet nurtured on petroleum, will be phased out through scrappage.

However, the period of phase-out may be very lengthy because the world shipping fleet consumes very little of the world's energy, and that which it does consume is the lowest grade petroleum fuel, which can be made from the least valuable types of crude oil for a very small processing cost.

### 6.4.2 LOAD FACTOR

The previous comparison between various prime movers for each type of fuel has been made for a 90% load factor. The choice of load factor can be very critical in selecting the best fuel/prime mover combination. Possible load factors by class of trade are summarized in Table 6-12.

TABLE 6-12

LOAD FACTORS OF VARIOUS TYPE SHIPS

| | % |
|---|---|
| • Tankers, Bulk Containers | |
| - Long Hauls | 80-90 |
| - Short Hauls | 70-75 |
| • Grain Vessels - Long Hauls | 70-75 |
| • Dry Cargo - Bulk | 40-45 |

The comparison between a coal-fired boiler and a diesel engine for a 45% load factor is shown in Figure 6-2.

The chart shows where the diesel engine would be attractive as a function of the delta investment/HP between the two types of engines and the delta fuel cost between coal and liquid diesel fuel. The line has a slight curvature in it since it has been assumed that the efficiency of the steam boiler decreased with size down to the 4500 HP engine. The delta investments used in this study are indicated on the chart, i.e. for a large ship (45,000 HP) an equal investment for a coil boiler and a diesel, with the coal boiler investment increasing as the size of the ship decrease to a delta of $360/HP for a 4500 HP engine. In this illustration, if coal cost $1.50/MBTU and a liquid fuel cost $3/MBTU, the delta fuel cost would be $1.50/MBTU. At this delta coal would be attractive for large ships at this load factor while a diesel engine would be the best choice for the medium and small size ships. If the delta fuel cost increased to $4/MBTU then coal would be the choice for the medium size vessel.

Figure 6-3 shows how load factor influences the choice between a diesel engine and a coal fired boiler. At the 90% load factor, even the small size vessels would find coal attractive at a fuel cost delta of $3/MBTU. As the load factor decreases, the diesel powered vessel will become more attractive. Thus, the following would appear to be true:

- Large size vessels should find coal attractive at any load factor

- Medium size vessels would be in a breakeven position if they can get a liquid for a delta fuel cost of $3/MBTU at the 60% load factor. Above this delta fuel cost coal would be attractive

FIGURE 6-2

COAL FIRED BOILER VERSUS DIESEL ENGINES

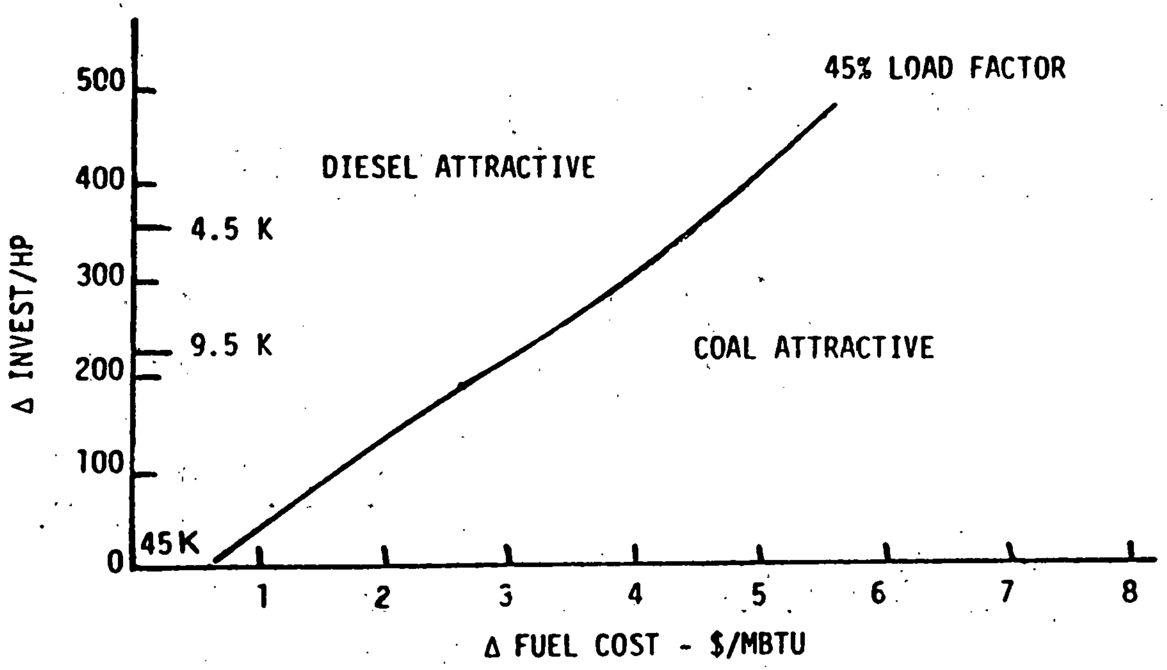
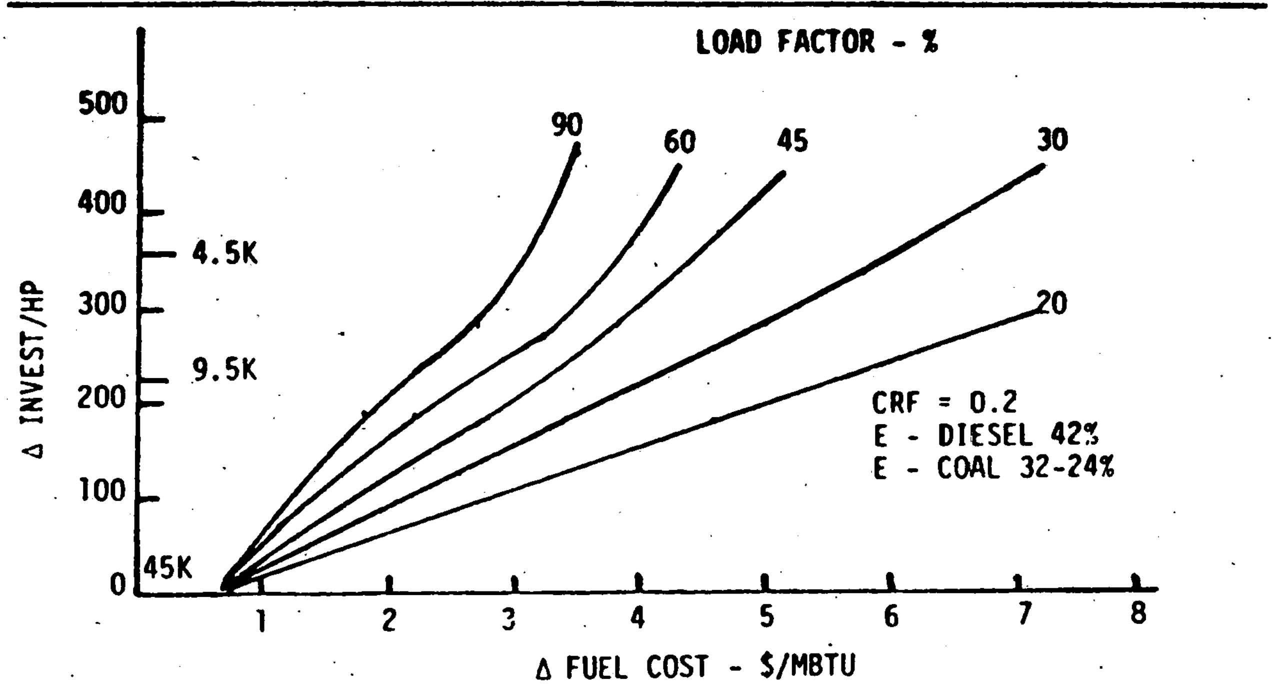


FIGURE 6-3

## COAL FIRED BOILER VERSUS DIESEL ENGINES



- Smaller size vessels will probably stay with diesel engines up to a fuel cost delta of $4-5/MBTU at a load factor of 40-45%.

### 6.4.3 CAPITAL RECOVERY

The above conclusions have been made for a capital recovery factor of 20% (about 10% DCF). The sensitivity of capital recovery factor is shown in Figure 6-4. For example, at a 12% DCF return, a medium size ship would burn coal if diesel fuel cost more than about $3/MBTU at a 90% load factor, or $3.50/MBTU at a 60% load factor. As the return level increases, the breakeven cost for diesel fuel increases slightly. For a small size ship, as the return level increases, the price a user would be willing to pay increases to around $5-6/MBTU at the 60% load factor.

### 6.5 FUEL CELLS

Phosphate-type fuel cells are no more efficient than a marine diesel engine and they need, generally, a better grade of fuel of the low sulfur distillate type. Their costs are expected to be about as follows in 1980 dollars.

| | $/HP |
|---|---|
| Reformer, Cell and controls | 250 |
| DC Motors | 55 |
| Gears | 26 |
| | 331 |

This is for the engine components which would replace either a diesel engine ($186/HP) or a steam engine/boiler/condenser (about $150/HP).

Accordingly, unless certain special properties of the phosphate fuel cell permit substantial savings in auxiliaries, ship's power supply or shipyard installation, it would not appear to be competitive with other engines at sea.

The molten carbonate cell, which may become commercially available by about 1990, should have an efficiency of 50% and may therefore be competitive in certain circumstances.

Table 6-13 shows the cost of the horsepower year obtained with fuel cells in large and smaller sized ships on each of the fuels which could be used to drive them. Essentially these fuels are those which can provide hydrogen by steam reforming on the ship, viz.

FIGURE 6-4

DIESEL - COAL/STEAM COMPARISON

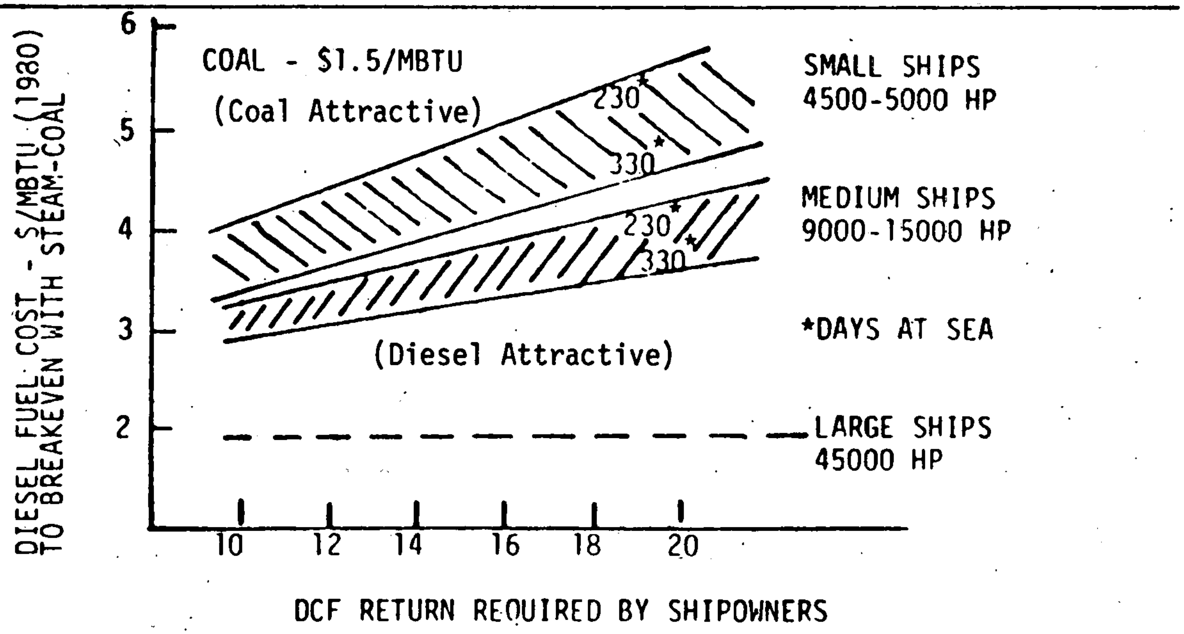


TABLE 6-13

Synthetic Distallate at ($4.90/MBTU)
Synthetic Distillate at ($9.00/MBTU)
Liquid Methane ($9.50/MBTU)

| | $/HP Yr. | | | |
|---|---|---|---|---|
| | Large Ships | | Smaller Ships | |
| Fuel Cost Of | $PO_4$ | $CO_3$ | $PO_4$ | $CO_3$ |
| $4.90/MBTU | 364 | 315 | 410 | 360 |
| $9.00/MBTU | 566 | 480 | 612 | 525 |
| Liquid methane | 591 | 500 | 636 | 545 |

The main point to be noted is that unless some equivalent feedstock at about $4.90/MBTU can be made available for use of these cells, they stand no chance of competing with liquid-fuel-fired steam, coal-fired steam or diesel engines.

If shale distillate is made available, it seems certain that something cheaper would be available for the diesel engine (e.g. raw shale).

Therefore, the best possibility for the fuel cell at sea would be for large ships using molten carbonate cells, giving the HPY for $315. This would be close enough to diesel at $284/HPY to justify a closer examination.

However, given coal at $0.9-1.6/MBTU the coal-fired steam boiler/turbine should be able to undercut the molten carbonate fuel cell by $100/HPY for large and smaller vessels.

Under an unlikely scenario, wherein methane became the only fuel available, the molten carbonate fuel cell would have the lowest cost ($/HPY) of any engine because of its superior efficiency.

## 6.6 POSSIBLE ROLE OF A SAILING SHIP

If a sailing ship could rely on the wind for 80% of her propulsion, and handled the other 20% with a diesel engine running on raw shale oil, 1584 horsepower hours would be used per year through each installed HP of the diesel engine at a cost of $158 for capital, fuel and maintenance. That would leave a saving of $100/HPY over the lowest cost competitor (namely a coal-fired steamship). This $100/HPY, applied as capital, breaks even if the sails and their controls can be installed for $500/horsepower or less. Sails for a 30 foot pleasure vessel cost about $200/horsepower. The 80/20 split may be very optimistic in which case the economic driving force would be much less.

This approach would have obvious environmental and energy conservation advantages. Full diesel power has been envisaged for this vessel to insure safety and a good time schedule.

If the price of coal were to rise, the applicable capital per horsepower of sail would stay in the proportion 400 times the cost of coal in $/MBTU.

The feasibility of using sailing ships for the American Merchant Marine was investigated at Michigan University.(6-7) They found that commercial sailing ships would be limited in size to about 50,000 ton cargo dead weight. This limit is a result of the need for deep draft to develop side force in on-wind sailing, and of the need for a reasonable aspect ratio. Channel depths dictate the limit in the former instance; considerations of reasonable spar structure is the limit in the latter case. The study did find that it should be quite feasible from a technical standpoint to handle the sails by deck-mounted machinery so that the crew duties would be comparable to those of a powered vessel.

## 6.7 OVERALL ENERGY EFFICIENCY

Table 6-14 shows the energy input in terms of primary fuel, which is required to produce one HPH (2547 Btu of work energy) taking into account all the energy lost in conversion to engine fuel, lost in transportation to the engine, and lost as reject heat at the engine itself.

The figures were calculated using the expression:

$$\underset{\text{(mine to propeller shaft)}}{\text{Btu/HPH}} = \frac{2547}{E} \times F_1 \times F_2$$

Values for $F_1$ and $F_2$ (which relate to the efficiency of engine fuel production from the primary source, and to the ratio of gross to net heat content) are given below.

The values for E, the efficiency of the engine, is the maximum value given in Table 6-3.

The most efficient combination of fuel and engine is a diesel running on raw shale oil, closely followed by Stirling running on coal.

It is interesting to note the relatively small difference between a steam engine running on solid coal (8.3 k Btu/HPH) and a molten carbonate cell running on highly refined, highly processed coal liquids (9.8 k Btu/HPH). Of course on a dollar basis the spread between these two examples is much more extreme, $190-240/HPY for coal/steam versus $480/HPY for the $CO_3$ cell.

|  | $F_1$ (Gross/Net) | $F_2$ (Mine Btu/fuel Btu) |
|---|---|---|
| Coal | 1.020 | 1.02 |
| Raw shale | 1.065 | 1.11 |
| Coal/oil slurry | 1.040 | 1.14 |
| Shale liquids | 1.068 | 1.59 |
| Coal liquids | 1.055* | 1.82 |
| Methane | 1.125 | 1.85 |

* 1.080 for coal derived gasoline.

# TABLE 6-14

## OVERALL THERMAL EFFICIENCY FROM RESOURCE TO SHAFT POWER

### k Btu/HPH Mine to Propeller

| Fuel | Engine | | | | | | Fuel Cells | |
|---|---|---|---|---|---|---|---|---|
| | | | Gas Turbine | | | | | |
| | Steam | Diesel | Simple | Regenerative | Stirling | Free Piston | $PO_4$ | $CO_3$ |
| Coal | 8.3 | -- | -- | -- | 7.6 | -- | -- | -- |
| Coal/oil slurry | 9.4 | 7.2 | -- | -- | 8.6 | -- | -- | -- |
| Raw shale | 9.4 | 7.2 | 10.8 | 8.6 | 8.6 | 10.8 | -- | -- |
| Shale liquids | 13.5 | 10.3 | 15.4 | 12.4 | 12.4 | 15.4 | 10.5 | 8.7 |
| Coal liquids | 15.3 | 11.6 | 17.5 | 14.0 | 14.0 | 17.5 | 11.9 | 9.8 |
| Liquid methane | 16.6 | 12.6 | 18.9 | 15.1 | 15.1 | 18.9 | 12.9 | 10.6 |

## 6.8 MARINE TRANSPORTATION (Other Than The Foreign Sector)

Energy consumption in Marine Transportation is highest in the foreign trade sector, but most of the ships in that trade are not U.S. flag, and most of the fuel used is not U.S. derived. There are however six other sectors which are mainly U.S. flag (and some Canadian) which in total consume about 0.5 quads of energy/yr., most of it purchased in the United States.

The following table shows the pattern of consumption in 1974, with a projection for the year 2000.

TABLE 6-15

Productivity and Energy Consumption of the Marine Transportation Industry

| | 1974 | | | 2000 | | |
|---|---|---|---|---|---|---|
| Industry Sector | Long Tons of Cargo Moved (millions) | Energy Consumed (quads) | % | Long Tons of Cargo Moved (millions) | Energy Consumed (quads) | % |
| Foreign trade | 654.9 | 2.360 | 80.5 | 1573.6 | 5.600 | 84.3 |
| Great Lakes | 175.3 | 0.052 | 1.8 | 325.0 | 0.100 | 1.5 |
| Inland waterways | 535.8 | 0.089 | 3.0 | 789.0 | 0.100 | 2.2 |
| Coastal | 213.0 | 0.112 | 3.8 | 403.0 | 0.300 | 3.8 |
| Offshore | -- | 0.064 | 2.2 | -- | 0.200 | 2.9 |
| Pleasure craft | -- | 0.225 | 7.6 | -- | 0.300 | 3.8 |
| Fishing and miscellaneous | -- | 0.032 | 1.1 | -- | 0.100 | 1.5 |
| Total | 1579.0 | 2.934 | 100.0 | 3090.6 | 6.700 | 100.0 |

Source: Ref. 6-8

It will be seen that the largest proportional growth has been forecast for "Offshore" activities, meaning drilling and ocean-floor mining operations. Fishing will increase due to the extension of coastal limits to 200 miles. Pleasure craft are forecast to grow only modestly in their energy demands, and to decline significantly in terms of percentage.

In total, the portion of fuel used in marine transportation from U.S sources was 0.8 quads in 1974, and is forecast to be 1.1 quads in 2000 A.D.

## GREAT LAKES SHIPPING

Iron ore, coal, and mining products account for 90% of the tonnage movements on the Great Lakes. Most vessels are U.S. flag, about 50% steam, 50% diesel.

## INLAND WATERWAYS (Rivers and canals)

Goods are moved on these waters principally by grouped barges, powered by diesel tugboats or towboats. The engines are essentially railroad type diesel engines fueled by all-distillate fuel.

## COASTAL

A large part of the coastal tonnage is expected to be Alaska crude in medium-size tankers.

## OFFSHORE AND FISHING

The operations off-shore utilize essentially medium-speed railroad type diesel engines for drillings and for operating the small craft support between shore and rig. Fishing is likewise powered by diesel engines most of which are high speed and of modest horsepower, less than 1000 hp.

## PLEASURE CRAFT

These are fueled either by gasoline or by #2 diesel fuel of the type called Marine Gas Oil in international trade.

Essentially, extension of the study of marine transportation into these inland and domestic sectors draws attention to four distinct types of vessels:

- seagoing vessels essentially identical with those in foriegn trade and subject to the considerations discussed in that section
- lake-going vessels similar to the above but subject to more stringent requirements as regards environmental control
- tug-boats, etc., employing what are essentially railroad diesel engines
- smaller craft employing engines very similar to those used on the highway.

Accordingly the following possibilities are considered likely with regard to future fuels for each of these four classes of marine transportation.

## SEAGOING VESSELS IN COASTAL TRADE

New construction would favor coal-fired steam turbine propulsion except on the very important Alaska route. This is essentially a sea-link between petroleum pipelines and as such would be the last to suffer shortage of petroleum derived diesel fuel. The ships' fuel could be cut from the crude oil by a simple topping operation on shore. Regenerative gas turbines or combined gas turbine/steam turbine engines would be a distinct possibility on this route especially if arrangements could be made to store fuel of special type at each end of the voyage.

## LAKE-GOING VESSELS

Vessels on the Great Lakes have a much longer life than those in ocean trade. Fifty years is not an unusual period of activity for such vessels.

Thus a vessel built today might be expected to continue in service until 2030 AD. It would probably be prudent to build such vessels for steam turbine propulsion and to make arrangements for either oil or coal to be used as fuel. Such a vessel would provide an excellent test bed for fluidized combustion.

Furthermore the Great Lakes are sufficiently limited geographically to make coal handling feasible at most of the ports. Cleveland could become a major bunkering port for coal. On the other hand, shale oil (or Canadian Tar Sand Oil) could be made available at all these ports without special economic hardship.

## TUG BOATS ON INLAND WATERWAYS

If raw shale oil is made available at $3/MBtu, these craft would have an assured future with the type of diesel engine that they presently use. Under the crowded conditions of navigation that these craft encounter, it is doubtful that the medium-to-high speed diesel engines would be given up, even if diesel fuel rose in cost to $5/MBtu.

## PLEASURE CRAFT

These craft use essentially highway fuels and would develop, or change, in parallel fashion to highway traffic.

Fuels such as alcohol would be serious technical contenders for the engines which currently use gasoline, but cost would favor the use of shale or coal derived gasolines. A return to sail power would be logical as fuels increase in price.

## 6.9 RESEARCH NEEDS

Engine manufacturers are performing much research into the possibilities of running modified diesel engines and modified gas turbines on low quality fuels, similar in properties to today's bunker fuel oil. The main question in their minds concerns, if, when, and at what price such a replacement might become available.

Since shale oil seems to be the only candidate which comes close to fitting the description of a bunker fuel replacement, shale oil and coal could be the only serious contenders for future ship propulsion.

In steam propulsion, a great deal of experience is available from oil-fired ships. Steam cycles could be improved to increase efficiency. For example, a ship rated at 32% efficiency in these examples could be raised to 37% by adoption of more severe steam conditions such as 1900 psig/1050°F/reheat. However, the amount of capital which is justifiable to make such an improvement depends on the value of the coal saved, which would only be $12/horsepower year for a large vessel with coal at $1.23/MBtu. That is, at 20% capital recovery one would only wish to spend a maximum of $60/horsepower to effect the improvement. Whether this is practical or not calls for a closer inquiry into the actual costs of coal-fired boilers for sea-going application. $60/horsepower translates into about $10 per hourly pound of steam.

In turn, the establishment of reliable boiler costs requires agreement as to the environmental restraints which are required of coal-fired ships in terms of emissions to air and water. Such vessels would probably have to burn a cleaner fuel in harbor.

Some R&D ideas for the marine area are outlined below.

- A study on logistics of coal supply to ships - is it feasible - is space available to store and handle the coal?
- A study on coal/oil slurry for existing vessels - could it be used in current boilers? What are the storage requirements; is it possible to modify a low speed diesel to burn a slurry?
- A study on the best type of boilers for coal - Is fluid bed combustion a possibility? What are the environmental restrictions; the size limitations ?
- Should fuel cells be considered for smaller ships?
- A study on the future market for various fuel in each class of vessels.
- Investigate if a low speed diesel can burn coal.
- Study how the transition will be made from the current fuels to alternate fuels.

# APPENDIX 6-A

## CAPITAL INVESTMENT AND ENGINE EFFICIENCY DETAILS CHOSEN FOR TABLE 6-3

### FIRM DATA

Columns (1) and (3) reflect data obtained from Exxon International based on orders for shipbuilding 1980. Column (1) is a 400 000 ton - 45 000 HP steamship with efficiency 32%.

Column (3) is a 22 000-ton low-speed diesel driven ship, 9500 HP with efficiency 42%. Both have sufficient steam provided for cargo heating.

The auxiliaries which are common to both vessels include:

Auxiliary condenser, air ejector
Fans, uptake and stack
Lube oil system
Fuel oil system
Drinking water, wash water, sanitary system
Auxiliary steam system
Feed, condensate, salt water system
Salt water evaporators
Cargo pumps and turbine, steam piping
Machine shop

Not all of these would be considered part of the propulsion plant by all vessels owners but they were treated this way for all ships in this study. That means that about $150 of each installed horsepower for each vessel is accounted for by this list of auxiliaries.

In the case of gas turbine ships the figure has been reduced because the fuel and lube systems are included in the costs of the engine itself.

Column (5), the regenerative gas turbine contains the following figures obtained from General Electric for a 30 000 HP, 5002-BR engine.

| | Total Plant 30 000 HP | $/HP |
|---|---|---|
| Engine | $5 million | 167 |
| Gearing and propeller | $1.6 million | 53 |
| Fuel washing and vanadium inhibition | $0.4 million | 13 |

In Column (5) the cost of the propeller is given as $53/HP for gas turbine ships, versus $20 for all other ships.

## DERIVATIONS

### A. Coal-Fired Boilers

The figure $230 for the coal-fired boiler in Column (2) represents $40 per hourly pound of steam, which is four times the cost of the corresponding oil-fired boiler in Column (1).

According to information provided by Foster Wheeler, this may be too conservative.

Shore-based boilers are selling for between $40 and $70 per hourly pound of steam depending upon the degree of air pollution control required.

The implications of boiler price are discussed in the text.

### B. Simple Cycle Gas Turbines

In Column (4) the cost of the engine itself has been taken as $75/HP. This is consistent with quotations of $100/kW for simple turbine electrical generation. The efficiency of 28% is taken from experience with FT 4A engines aboard transatlantic container ships operating on distillate fuel. The lower figures in parentheses (25%) applies to such ships when fueled with residual blends.

The discrepancy between the simple turbine auxiliaries at $125/HP versus $138 for the regenerative turbine is the $13 for fuel washing given by GE. Actually either vessel could employ the fuel washing and indeed would have to do so if raw shale oil were used.

### C. Stirling Engine Costs

A Stirling engine in the size range 9000 to 15 000 HP would be an entirely new development. Design and relative weight considerations alone (leaving out development costs) would place it at least 50% more costly than diesel. The figure of $300/HP in Column (6) was chosen on this basis. As in all cases, an error of $100 in capital estimate reflects as $20 per horsepower year and this is discussed in the text.

### D. Free Piston Engine Costs

In Column (7) the free piston engine has been costed just marginally above the firm diesel engine price.

### E. Shipyard Installation

The firm figures are $73 for large steamships, $148 for smaller diesel ships.

Stirling and Free Piston have been put in at $150 since they are applicable (if at all) to smaller ships.

Gas turbines have been given figures toward the lower end of the firm extremes, $75 for the simple turbines, $100 for the regenerative types. Coal-fired steam ships have been given $100 for installation, i.e. $27 more for installing the coal boiler and its fuel and ash handling equipment.

## F. Maintenance

The figure 0.21¢/HPH is from Exxon International experience, backed up by published examples in the diesel engine users handbook.

The free piston at 0.5¢/HPH is an extrapolation from the diesel case recognizing the heavy maintenance load experienced aboard the John Patterson.

Figures for oil-fired steam, coal-fired steam and for the gas turbines have been taken from corresponding published figures in plants generating electricity.

They are all less than the diesel case. An error of 0.1¢/HPH reflects as a change of $8 in the cost of a horsepower year.

Maintenance for the Stirling has been estimated to be the same as that of a simple gas turbine.

## G. Value of Cargo Space Occupied by Fuel

Coal-fired vessels require a 50% larger volume for fuel space, than is needed with any of the other fuels. (Methane does not have to be considered.)

To drive a horsepower unit for a 40-day voyage requires:

Diesel - 1 barrel of fuel oil

Oil-fired steam - 1.3 barrels of fuel oil

Coal-fired steam - 2 barrels of space for coal

Thus the coal-fired vessel could be considered to have lost 1 barrel of cargo space for every horsepower. In the year, that barrel of space could have carried 8 bbls of product (8 voyages per year).

At 50¢/barrel shipping charges (on a 40-day voyage), that lost space could have earned $4 which should be debitted against the cost of a coal-fired horsepower year. This is small compared with the cost of the horsepower year which is between $200-300. With new ships, the vessel could be built slightly larger to handle the coal storage. In the case of Colliers, the delta cost would be almost nothing.

## H. Scale-up and Scale-down Factors

While the firm data relate to vessels of different sizes

45,000 HP - steam
30,000 HP - gas turbine
9,500 HP - diesel

it is possible to make reasonable extrapolations of capital costs and engine efficiencies to ships of other sizes. Table 3-2 gives total costs per horsepower year for two sizes of ship on each fuel. The following criteria have been used to translate between the two sizes.

### Steamships

Engine, boiler, and shipyard installation costs have been scaled as follows:

$$\text{Total cost B} = (\text{size B}/\text{size A})^{0.8}\ \text{Cost A}$$

$$\text{Cost B/HPH} = (\text{size A}/\text{size B})^{0.2}\ \text{Cost A/HPH}$$

Thus a coal boiler cost of \$230/HP for a 45 000 HP ship becomes:

$$\$230 \times \left(\frac{45,000}{9,500}\right)^{0.2} = \$230 \times 1.364 = \$314/\text{HP}$$

for a 9500 HP coal-fired steam ship.

Propeller, auxiliaries and power supply have been costed at parity with the small diesel ship.

### Diesel Ships

No scaling factors have been used. The view taken is that the cost of a horsepower on a diesel vessel is essentially the same regardless of size.

### Gas Turbine Ships

\$30/horsepower was added to each gas turbine ship as she was scaled from 30 000 HP down to the 12 000 HP range.

### Stirling and Free Piston Engines

These were taken as having applications to small ships only.

### Efficiencies

Were scaled as follows:

| | Large Ships | Smaller Ships | Smallest Ships |
|---|---|---|---|
| Oil fired steam* | 32% | 28% | 25% |
| Coal fired steam* | 32% | 28% | 24% |
| Diesel | 42% | 42% | 42% |
| Simple GT (clean) | 28% | 26% | -- |
| " (dirty) | 28% | 25% | -- |
| Regen. GT (clean) | 35% | 34% | -- |
| " (dirty) | 34% | 32% | -- |
| Stirling | -- | 35% | -- |
| Free piston | -- | 28% | -- |

The possibilities for higher efficiency are discussed in the text.

### Maintenance

Figures were taken as the same for each individual engine regardless of ship size. Maintenance was increased to 0.22¢ for the case of a gas turbine running on dirty fuel.

### Fuel Cells

Were costed as follows:

| | $/HP | |
|---|---|---|
| | $PO_4$ | $CO_3$ |
| Cells, fuel processor and controls | 250 | 225 |
| DC Motors | 55 | 55 |
| Gears (45,000 HP) | 22 | 22 |
| " (9500 HP) | 26 | 26 |

Taking other auxiliaries, boiler and propeller as given for steam in the large engine size, and as given for diesel in the small engine size leads to the following total capital for machinery and auxiliaries in fuel-cell driven ships.

| | $/HP | |
|---|---|---|
| Size | $PO_4$ | $CO_3$ |
| 45,000 HP | 549 | 518 |
| 9,500 HP | 777 | 743 |

## HYDRAZINE AND HYDROGEN AS POTENTIAL FUELS

Suggestions have been made in the literature that hydrazine and hydrogen would be desirable fuels for fuel cells in marine applications(6-3,-4,-5) However, as was shown in this study, hydrazine is projected to cost at least six times as much as distillates from coal, so that it does not appear that hydrazine-based fuel cell systems could ever compete economically with fuel cells based on other fuels, or with other types of prime movers.

Considering the higher thermal efficiency possible with hydrogen in a KOH electrolyte fuel cell (60% versus 50% in a molten carbonate fuel cell) the effective cost of hydrogen gas at the manufacturing plant would be about equivalent to that of direct coal gasoline, but more expensive than indirect coal distillates. However, when bulk transportation costs to bring the hydrogen to marine storage depots are added, the equivalent cost of hydrogen, allowing for fuel efficiency differences, would be appreciably greater than the cost of liquid distillates from coal. In addition the costs for storing hydrogen at the marine depots would be considerable, and the logistics involved in maintaining hydrogen in storage at necessary ports of call around the world would be costly. Furthermore, the large costs involved in storing hydrogen on board ships (in metal hydrides, as gas under pressure, or as a cryogenic liquid) add another significant increment to the total costs for use of hydrogen which leads to the conclusion that hydrogen is completely uneconomic for marine use based on the cost structure for the fuels considered in this study.

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# 7. RAILROAD

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## 7.1 SUMMARY

U.S. railroads are currently powered largely by two major workhorses.

1. The 3000 HP diesel electric freight hauling locomotive which costs close to $100 for each horsepower deliverable to the electric motors which drive the wheels. Maintenance costs, reported annually by the operators to Interstate Commerce Commission average $25,000/yr (0.4¢/HPH delivered).
2. The 1600 HP diesel electric switching engine, which costs close to $160/HP, incurs approximately $12,000 for maintenance/yr.

Both types of locomotive spend considerable time with their engines idling.

With fuel at $3/MBtu, the current cost of diesel ($1980), the annual fuel costs are:

| | k $/Year for Fuel | |
|---|---|---|
| | Freight | Switching |
| Fuel consumed working | 160 | 18 |
| Fuel consumed idling | 12 | 10 |
| | 172 | 28 |

If the current cost of a horsepower year is defined as:

20% capital recovery + cost of fuel +
maintenance cost

then the following figures are derived by dividing each of the cost items given above by the total horsepower of the locomotive.

| | $ Cost per Horsepower Year | |
|---|---|---|
| | Freight | Switching |
| Capital | 21 | 33 |
| Fuel | 56 | 17 |
| Maintenance | 8 | 8 |
| Total | 85 | 58 |

Both engines are thermally efficient since they are based on the diesel cycle. However, there would be something of the order $4 per HPY in fuel to be saved on the freight operation, and $6 per HPY on the switching operation, if the extensive idling time were eliminated. Presently the operators view this modest expense as being justified in terms of minimizing total maintenance costs and in keeping the locomotive instantly available.

In order for an alternative prime mover to compete against today's diesel electric locomotive, it must show some advantage in one or more of the following ways:

1. lower capital cost
2. ability to burn a lower cost fuel than the diesel engine can burn (e.g. coal)
3. higher thermal efficiency
4. lower maintenance
5. qualify for the $4-6/HPY savings in idling fuel cost mentioned above.

An alternative engine would qualify on point (5) if it does not have to idle. However, this advantage could be lost if the many starts and stops cause increased maintenance. None of the alternatives considered in this report, are likely to better the current diesels in terms of lower capital.

Steam engines and Stirling engines would be able to burn coal. The low efficiency of a practical steam engine would offset part of the monetary savings associated with the low cost fuel, and both candidate coal burners would be much more expensive in first costs than the diesel electric prime mover. The first costs would be dependent upon the degree of air pollution control required.

Fuel cells are more efficient than the diesel engine, more expensive in first costs, lower in maintenance costs, and they would qualify for the non-idling bonus. The phosphate type fuel cell becomes competitive with the diesel locomotive for freight hauling when fuel costs rise above $6/MBtu.

Gas turbines have been employed on locomotives but have not competed economically with the diesel option except where fuel prices have been extremely low. This is partly because the gas turbines were left idling for lengthy periods, a mode in which their fuel consumption is much higher than that of the diesel engine.

A regenerative gas turbine would be closely competitive with diesel electric for freight hauling provided means could be found to obviate the need for idling. A simple cycle gas turbine or a regenerative GT might compete with the diesel for switching provided it could be supplied at a capital cost lower than $200 per horsepower. Economics would make it mandatory that the gas turbine be switched off for all but the actual working hours of operation, which for a switching locomotive add up to about six hours per day, and these six hours are not concurrent. Furthermore, switching is performed at low average power, about 25% of full power so that a gas turbine would be required which could maintain reasonable efficiency down to quarter load.

While it is beyond the scope of this study to investigate the electrification option in detail, the figures indicate that for freight hauling it must be considered seriously if conventional diesel fuel costs rise toward $8/MBtu.

For example, the total cost of operating a diesel engine on coal distillate at $9.00/MBtu is over $200/HP year, while an electric locomotive with three times the capital cost of the diesel and with electricity at 5.2¢/kWh provides the HP year for less than $150.

The $50 differential would provide capitalization for the necessary overhead lines.

Comparative cost data for all cases studied are discussed in the following sections.

## 7.2 BACKGROUND

The United States is unique in several respects regarding its railroads.

1. With the partial exception of Amtrak, the U.S. railroads are privately owned. In almost all other countries they are nationally owned, and are subsidized out of taxes at rates between 0.3% (U.K.) and 1.8% (Austria) of gross domestic product.

2. U.S. railroads are free to buy General Electric or General Motors locomotives (diesel electric) for one third the price of equivalent electric propulsion. These locomotives are relatively low in price, due to production in large numbers over many years. Foreign governments are often obliged to support their own locomotive manufacturers, who generally cannot compete in a free market with the U.S.-made locomotives.

   On the other hand, in these overseas systems, the cost of an electric locomotive is considerably less than that of the locally made diesel engine. U.S.-made electric rail vehicles are more costly than diesel locomotives.

3. Between 30 and 40% of the railways of Europe and Japan are electrified and their governments have plans to expand that percentage. Since the electrified portions are those which carry the heaviest traffic, about 60% of the railroad energy used in these countries is electrical. Thus, the electric vehicle manufacturers have an assured expanding market outside U.S.A.

Within U.S.A., electrification is almost negligible. The private companies are in competition with each other as well as with highway traffic. Their routes are long relative to the population they serve, and they lack much of the densely packed passenger routes that have favored electrification in Europe and Japan.

Thus, as long as the diesel engine can be provided with some kind of workable fuel at reasonable price, it is unlikely that there will be a move toward significant electrification.

## 7.3 CURRENT COSTS WITH DIESEL LOCOMOTIVES (Conventional Diesel Fuel at $3/MBtu)

The U.S. diesel/electric locomotive has a relatively low cost investment ($105-$163 per horsepower delivered to the wheel motors).

Unlike marine engines which work at full power for 60-90 percent of the year, locomotives fall into two main classes, freight handling and switching, neither of which utilizes the engine for more than a fraction of its full capability.

The following table shows the power and usage profile for the two classes of work.

TABLE 7-1

| | Hours Per Year | |
|---|---|---|
| Service | Freight Loco | Switching Loco |
| 3/4 to Full Power | 1145 | 114 |
| 1/4 to 3/4 Power | 1145 | 600 |
| 1/4 Power or Less | 1652 | 1100 |
| At Idle | 3942 | 6070 |
| In Shop | 876 | 876 |
| | 8760 | 8760 |

The result of these typical operating schedules is that each potential horsepower provides the following amounts of useful work to the wheel motors in the course of the year.

| | |
|---|---|
| Freight loco | 2098 HPH/yr |
| Switching loco | 434 HPH/yr |

During the hours of productive work, fuel is burned at reasonably high efficiency, of the order 30%. This is not as good as a marine diesel engine, but considering the large amount of time spent at very low load it is still impressive.

During the time spent idling, fuel is burned, the expressed justification being that the fuel so consumed is less costly than the maintenance which would be needed if the engine were started and stopped repeatedly.

Fortunately, the amount of fuel burned per hour at idle is only one-twentieth part of the fuel burned per hour at full load.

In considering alternative prime movers, the question of whether idling is needed or not, could furnish an advantage. An engine which could be stopped and readily restarted (such as an electric motor, or a fuel cell) would be credited with saving the fuel that today's diesel operation consumes. This provides a larger advantage in the case of switching engines. On the other hand if an engine must be kept idling, and if it consumes more fuel at idle than the diesel does, it would incur a greater penalty. A steam engine would probably suffer this way.

With regards to maintenance, again there would be two periods to consider -- that which is required by the hours of productive work, and that which is required during the hours of idling. For the diesel engine these are estimated to be:

| | Maintenance ¢/HPH | | |
|---|---|---|---|
| | Lube | Other | Total |
| Productive work | 0.16 | 0.16 | 0.32 |
| Idle | 0.04 | -- | 0.04 |

During productive work, the maintenance is assessed on the horsepower hours presented to the wheel motors, which are supplied as a combination of full power, half power and low power operation.

During idling, no useful horsepower hours are produced. The concept of ¢/HPH is based on the horsepower hours which could have been produced, were the engine at full power.

All these analyses are based on the horsepower hours delivered to the wheel motors, and since that power comes indirectly from the diesel engine via an alternator (for freight locos) or a DC generator (for switching locos), the efficiency of the diesel engine has to be adjusted for the two generator efficiencies which are respectively:

| | |
|---|---|
| Alternator | 95% |
| DC Generator | 92% |

Thus the efficiency of each locomotive at the wheel motors is derived as follows:

| | Efficiency of Diesel Engine | Efficiency of Electric Generation | Overall Efficiency |
|---|---|---|---|
| Freight | 32.5 | 95 | 30.9 |
| Switching | 32.2 | 92 | 29.6 |

Accordingly, fuel consumption during the productive work period is:

| | HPH/Yr | Eff. | Btu/HPH | MBtu/Yr |
|---|---|---|---|---|
| Freight | 2098 | .309 | 8243 | 17.3 |
| Switching | 434 | .296 | 8605 | 3.7 |

Fuel consumption during idle is 330 Btu per hour for each horsepower.

| | Hrs/Yr at Idle | MBtu/Yr |
|---|---|---|
| Freight | 3942 | 1.3 |
| Switching | 6070 | 2.0 |

If the total cost of a horsepower year is defined as the sum of:

Capital recovery (investment x 0.2) +

Fuel used for productive work +

Fuel used at idle +

Maintenance incurred during productive work +

Maintenance incurred at idle

then these are the two cases for a typical freight locomotive, and a typical switching locomotive based on fuel at $3/MBtu. Capital investment is $105/HP for freight, $163/HP for the switching engine, both in terms of horsepower deliverable to the wheel motors.

| | | $/Horsepower Year | |
|---|---|---|---|
| | | Freight | Switching |
| (1) | Capital recovery | 21.00 | 32.60 |
| (2) | Fuel for work | | |
| | 2098 HPH | 51.90 | -- |
| | 434 HPH | -- | 11.10 |
| (3) | Fuel for idling | | |
| | 3942 hrs | 3.90 | -- |
| | 6070 hrs | -- | 6.00 |
| (4) | Maintenance for work | | |
| | 2098 HPH | 6.70 | -- |
| | 434 HPH | -- | 5.80 |
| | (1800 hrs working) | | |
| (5) | Maintenance for idle time | | |
| | 3942 hrs | 1.60 | -- |
| | 6070 hrs | -- | 2.40 |
| | Totals | 85.10 | 57.90 |

The split between maintenance items (4) and (5) is somewhat arbitrary, since it is impossible to know exactly what portion of the maintenance is incurred during working time versus that during idle.

Lube consumption of 2 grams per HPH working, and 0.5 gms per available HPH during idle has been assumed. The totals add to the reported figures of $25,000/yr for the freight locomotive and $12,000/yr for the switching engine.

An article appeared in the British journal, The Economist, July 15, 1978 which stated that maintenance costs for a British diesel train are about twice those for fuel. While maintenance costs of diesel engines are substantial compared with some other engines, this information given in The Economist appears to be out of line with normal practice by a factor of ten. Nonetheless, the article defended electrification largely on the grounds that it would save this enormous maintenance cost. This subject is discussed further in Appendix 7-I.

## 7.4 PRIME MOVERS CHOSEN FOR COMPARISON WITH THE DIESEL ELECTRIC LOCOMOTIVE

A brief description of each candidate prime mover, with its potential economic advantages and disadvantages follows in this section. The cost components for the various engine/fuel combinations are shown in Table 7-2.

### 7.4.1 Steam Engine

Steam locomotives have a history nearly as long as the railroad itself, and some are still running on a variety of fuels, coal, firewood, residual petroleum fuel, etc. These relatively antique models have a low thermal efficiency, usually below 10%. That is not because the steam cycle itself is inherently inefficient, indeed it is not, but rather because the two requirements for efficiency are difficult to obtain on a train.

1. High pressures, with suitable superheat cannot be obtained in fire-tube boilers. Fire-tube boilers were chosen for railroad use because of their compactness and reliability.

2. About half the efficiency of a good steam cycle comes from the work done in the large low pressure end of the turbine, as steam which has already fallen from boiler pressure to atmospheric, expands further into the near-vacuum of the condenser where it emerges from the last blades (or from the last cylinder of a multiple expansion engine) as a wet fog at about 100°F.

Almost all steam locomotives built in the past made no attempt to condense the steam, forfeiting at least half the available work in the exhaust to atmospheric pressure. The potential benefit of a condenser was fully understood and was employed in ocean-going steam engines where a very convenient heat sink existed, namely the ocean itself.

The sacrifice in efficiency resulted in a compact engine, and the capital savings were used to offset the augmented fuel cost in the economic balance. Attempts to incorporate some condensing capacity aboard locomotives in the 1930s were judged not to be worth the trouble and expense.

Data on an advanced locomotive steam engine (1940 vintage) have been given by Babcock and Wilcox(7-3). It comprised a coal stoker fired water tube boiler (51 400 lbs of steam per hour, 600 psi, 900°F) driving a 4500 HP steam turbine/electric plant. The steam was not condensed. Accordingly, efficiency was modest at 17% full to half load, 14% at low load and there would be a requirement of about 1500 Btu per hour per HP, for idling.

The efficiency could be raised to 28% given a condenser, but such a concept is probably not practicable. The condenser if practicable would bring two advantages to the steam system.

- it would increase efficiency from 17% to 28%.
- it would reduce the amount of steam required to produce one horsepower hour.

Therefore the boiler cost, which is estimated to be $230/HP for the non-condensing turbine would fall in proportion to $140 with the condenser. The turbine, estimated to cost $50/HP for the non-condensing case, would become larger with a condenser and rise in cost to $100/HP.

## TABLE 7-2

### COST COMPONENTS OF ENGINE/FUEL COMBINATIONS FOR RAILROADS*

| | Diesel | Steam | Stirling | Gas Turbine Simple | Gas Turbine Regen. | Electric | Fuel Cells PO$_4$ | Fuel Cells CO$_3$ |
|---|---|---|---|---|---|---|---|---|
| Capital Cost $/HP - Freight | 105 | 300 | 300 | 133 | 200 | 315 | 307 | 274 |
| - Switching | 163 | 300 | 300 | 200 | 300 | 489 | 301 | 268 |
| Thermal Efficiency - Peak (29%) | 38 | 17 | 35 | 28 | 36 | 100 | 42 | 50 |
| - 1/2 Power (29%) | 38 | 17 | 35 | 25 | 35 | 100 | 42 | 54 |
| - Low Power (42%) | 25 | 14 | 25 | 15 | 24 | 100 | 42 | 52 |
| - Btu Consumed at Idle/HP | 330 | 1500 | 720 | ------- No Idling ------- | | No Idling | ------- No Idling ------- | |
| Maintenance - $/HPH (or Working Hour) | .0032 | .0013 | .0015 | .0019 | .0022 | .0001 | .0018 | .0018 |
| - $/HP (During Idling) | .0004 | .0008 | .0007 | -- | -- | -- | -- | -- |
| - $/HPH (with Frequent Stops) | -- | -- | -- | .0030 | .0030 | -- | -- | -- |
| Apportionment of Maintenance - $/HPHYr. | | | | | | | | |
| Freight (Fr) | | | | | | | | |
| 2098 HPH | 6.70 | 2.72 | 3.15 | 3.98 | 4.60 | 0.2 | 3.77 | 3.77 |
| 3492 Hrs Idling | 1.60 | 3.50 | 3.07 | -- | -- | -- | -- | -- |
| | 8.30 | 6.22 | 6.22 | 3.98 | 4.60 | 0.2 | 3.77 | 3.77 |
| Switching (Sw) | | | | | | | | |
| 434 HPH (1800 hrs) | 5.80 | 0.56 | 0.65 | 5.40 | 5.40 | 0.04 | 0.78 | 0.78 |
| 6070 Hrs Idling | 2.40 | 5.26 | 4.60 | -- | -- | -- | -- | -- |
| | 8.20 | 5.82 | 5.25 | 5.40 | 5.40 | 0.04 | 0.78 | 0.78 |

| Fuel Costs $/HPYr. | Diesel Fr. | Diesel Sw. | Steam Fr. | Steam Sw. | Stirling Fr. | Stirling Sw. | Simple Fr. | Simple Sw. | Regen. Fr. | Regen. Sw. | Electric Fr. | Electric Sw. | PO$_4$ Fr. | PO$_4$ Sw. | CO$_3$ Fr. | CO$_3$ Sw. |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $/MBtu | | | | | | | | | | | | | | | | |
| ($1.23) | 22.8 | 7.0 | 51.2 | 20.6 | 26.1 | 10.4 | 30.7 | 6.8 | 22.6 | 4.8 | -- | -- | 16.0 | 3.3 | 12.9 | 2.7 |
| ($2.80) | 52.0 | 15.9 | 116.6 | 46.9 | 59.4 | 23.7 | 69.9 | 15.5 | 51.4 | 11.0 | -- | -- | 36.4 | 7.5 | 29.4 | 6.1 |
| ($3.00) | 55.8 | 17.1 | 125.0 | 50.2 | 63.7 | 25.4 | 74.9 | 16.6 | 55.0 | 11.8 | -- | -- | 38.9 | 8.1 | 31.5 | 6.5 |
| ($4.90) | 91.1 | 27.9 | 204.1 | 82.0 | 104.0 | 41.4 | 122.3 | 27.2 | 89.9 | 19.2 | -- | -- | 63.6 | 13.2 | 51.4 | 10.6 |
| ($5.55) | 103.2 | 31.6 | 231.2 | 92.9 | 117.8 | 46.9 | 138.5 | 30.8 | 101.8 | 21.7 | -- | -- | 72.1 | 14.9 | 58.2 | 12.0 |
| ($6.40) | 119.0 | 36.5 | 266.6 | 107.1 | 135.8 | 54.1 | 159.7 | 35.5 | 117.4 | 25.1 | -- | -- | 83.1 | 17.2 | 67.1 | 13.9 |
| ($8.30) | 154.3 | 47.3 | 345.7 | 138.9 | 176.1 | 70.2 | 207.1 | 46.0 | 152.2 | 32.5 | -- | -- | 107.8 | 22.3 | 87.0 | 18.0 |
| ($9.00) | 167.3 | 51.3 | 374.8 | 150.6 | 191.0 | 76.1 | 224.6 | 49.9 | 165.1 | 35.3 | -- | -- | 116.8 | 24.2 | 94.4 | 19.5 |
| ($9.20) | 171.0 | 52.4 | 383.2 | 154.0 | 195.2 | 77.8 | 229.6 | 51.0 | 168.7 | 36.0 | -- | -- | 119.4 | 24.7 | 96.5 | 20.0 |
| ($9.50) | 176.6 | 54.1 | 395.7 | 159.0 | 201.6 | 80.3 | 237.1 | 52.7 | 174.2 | 37.2 | -- | -- | 123.3 | 25.5 | 99.6 | 20.6 |
| ($21.20) | 394.0 | 121.7 | 883.0 | 354.9 | 449.8 | 179.3 | 529.0 | 117.5 | 388.8 | 83.0 | -- | -- | 275.3 | 57.0 | 222.2 | 45.4 |
| ($14.90) | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | 79.6 | 16.5 | -- | -- | -- | -- |

* All cost are in terms of 1980 dollars.

The improved efficiency would produce an annual fuel saving of \$20/HP (coal fuel in freight service) so that the total capital available toward the purchase of a condenser would be:

| | \$/HP |
|---|---|
| Boiler credit | 90 |
| Turbine debit | -50 |
| Fuel credit (\$20 ÷ 0.2)* | 100 |
| Net | \$140/HP |

* 0.2 is the Capital Recovery Factor.

In the case of a switching engine, because its fuel consumption is much less, the available capital would be \$70/HP.

However, apart from the monetary questions, i.e. whether a condensing system can be bought for this available capital, there are serious practical difficulties. The standard condenser for 4500 HP service has dimensions about 12' x 12' x 8' with the turbine mounted above it, and it requires circulation of about 6000 USG/minute of cooling water. Since such a volume of water is not available to a train in the way that it is to a ship, air cooling, either directly or via a mobile cooling tower would be needed, and this would require an entirely new design. Conventional cooling towers rely on height to induce a cooling draft, and such would not pass under bridges.

The option of a condensing cycle should not be entirely ruled out, but the fact that locomotive designers seem never to have considered condensers suggests that they are impractical on railroads.

The candidate steam engine has been taken as a 17% efficient machine costing \$300/HP with electric generation from the turbine/alternator feeding power to wheel motors. There would be considerable air pollution with such a locomotive. If an efficient fly-ash precipitator were included, the capital cost could rise toward \$400/HP. For $SO_2$ control as well as fly ash the cost could go to \$550/HP taking a cost of \$42/hourly pound of steam, the lowest cost of a fully-equipped stationary coal boiler. Also, practical difficulties of negotiating bridges could again appear.

For maintenance costs, a figure of 0.13¢/HPH has been taken, namely about one-third of the corresponding diesel engine cost.

There seems to be no reason to consider a liquid fueled steam locomotive since its efficiency is low, and even if the lowest cost oil-fired boiler could be employed, the capital outlay would be higher than either the diesel or regenerative turbine.

### 7.4.3 Stirling Engine

The Stirling Engine has been costed in this study at $300/HP. This estimate is made on the following basis. U.S. railroad diesel locomotives are very low in price by world standards. The regenerative GT at $200/HP is a better yardstick of price for a developing engine. Stirling, being more complicated would cost 50% more than $200, i.e. $300/HP.

The efficiency of the Stirling is good, its maintenance should be less than that of the diesel engine, and it could be a definite contender if it can burn coal.

While the Stirling engine requires a larger heat sink than the diesel engine radiator (possibly twice as large) the problems are not on the scale that was mentioned for the steam condenser. Nevertheless, today's diesel locomotives are tight on cooling capacity, so more space would have to be found for the Stirling. The figure of $300 per HP may be too low.

Again, if coal were to be used, questions pertaining to the required level of fly ash removal and $SO_2$ control would have to be answered, and if these were to be as strict as they are for stationary use, an additional $200/HP could be needed.

### 7.4.3 Gas Turbines

In comparison with diesel engines, gas turbines possess several features which turn out to be advantageous in many applications.

1. they weigh about one-tenth the mass of equivalent diesel power
2. they cost less per horsepower, at least in size ranges above 10,000 HP
3. they need no cooling water, and much less lubricant.

Against these potential advantages, the simple cycle GT is less efficient at full power, the efficiency falls off very rapidly as it approaches quarter power, and if the engine is idled it consumes about a quarter of its full power fuel consumption. Therefore, it is not idled, but is equipped to start and stop, since full power can be obtained from full stop in about one minute. There is a penalty in terms of shortened life for frequent stops. A gas turbine locomotive in freight service might operate with only one start per day, whereas one in switching service might have to start and stop ten or twelve times per day.

The efficiency, and the efficiency/load profile can be improved by adoption of a regenerative cycle.

Gas turbines in the sizes of interest to railroad work are available, and have been used on trains in U.S.A., Canada, Japan and Germany. However, in these size ranges (1500-5000 HP) the investment costs are not less than those of the U.S. diesel electric locomotive. Figures suggested by AVCO(7-4) Lycoming are of the order $133/HP for simple cycle, $300/HP for a regenerative cycle similar to that used in the 1500 HP U.S. Army tank engine.

The light weight of these engines will be a disadvantage for these locomotives which frequently have to have deadweight added to supplement the weight of a diesel engine.

| | Weight, lbs. | % Weight of Total Locomotive |
|---|---|---|
| 3000 HP diesel engine plus alternator/rectifier | 48 000 | 16 |
| 3000 HP GT | 4 000 | 1.3 |

A regenerative gas turbine with an efficiency/load profile similar to that of a diesel engine may come close to competing for freight hauling.

1. it has the advantage (an advantage which is forced upon it) of not burning fuel at idle
2. it must however, not incur so much extra maintenance that this advantage is wiped out.

Maintenance for gas turbines is of the order 0.2¢/HPH for runs of 10-12 hours per day at an average of half load, such as freight hauling operation. If the turbine were started and stopped 10 times in a day the maintenance would rise to 0.3¢ per hour of running.

Clearly, the gas turbine is not naturally suited to switching operation, because of the many starts involved, plus the fact that its average operation would be at quarter power during the few hours that it works.

Caterpillar recently announced(7-5) that they have developed a compact regenerative turbine (about $200/HP with alternator) with an efficiency between 30 and 36 percent over a wide range of load. A 3000 HP model is available which might suit the freight locomotive requirement.

However, conversations with Caterpillar revealed that they had thought about this potential application, but did not think that it could displace the diesel economically. Apparently at today's fuel price, the gas turbine is a borderline contender, used to a limited extent in high speed passenger trains. An increase in fuel prices would, if anything make the gas turbine slightly less competitive. However, the difference in total costs is not very great, and on certain fuels such as ethanol, which certainly would operate much more satisfactorily in a gas turbine than in a diesel engine, the balance might easily swing in favor of the GT.

### 7.4.4 Electric Train

While it is beyond the scope of this study to discuss the full implications of electrification of U.S. railroads the following case has been included for comparison.

The electric locomotive has been costed at three times the cost of the diesel locomotive. That is for the locomotive alone, not for provision of overhead lines, etc. It will be seen from the appendix that The Economist article suggested that both the locomotive and the overhead lines could be provided for three times the horsepower cost of a U.S. diesel freight locomotive, but that was for densely populated passenger routes.

With "fuel" at 5.2¢/kWh, i.e. $14.90/MBtu, and 100% efficiency (direct to the wheel motors) the horsepower year costs $143 for freight and $114 for switching. This only becomes competitive against diesel if diesel fuel is unavailable at less than $6/million Btu. Again, this conclusion is valid only if the overhead lines have been provided and fully depreciated.

### 7.4.5 Fuel Cells

A separate appendix (7-II) has been devoted to a full discussion of fuel cells and their application to railroads. Below, is a condensation of the main points.

Fuel cells, while costly are no more so than several of the other engines considered in this study. Their efficiency is the highest, maintenance is reasonable, and they can be switched off to save fuel which other engines waste when idling. Finally, they may be capable of being electrically coupled to the wheel motors in a way that would save part of the losses which today's locomotives suffer in the alternator or direct current generators (viz., the 5% loss on freight engines and the 8% loss on switching locos).

A phosphoric acid cell looks as though it could break even with a diesel engine at a fuel cost of $5/MBtu. Similarly a molten carbonate cell would break even at a fuel cost of $4/MBtu.

The weight of the fuel cells is somewhat higher per horsepower than that of an equivalent diesel engine, but this would not necessarily incur any disadvantage.

| | Mass of Engine Plus Fuel, Lbs | % of Mass of Total Locomotive |
|---|---|---|
| 3000 HP diesel engine plus alternator rectifier and fuel | 71,000 | 24 |
| phosphate fuel cell plus voltage regulator plus fuel | 88,000 | 30 |

A detailed design and engineering study is needed to determine the feasibility of using fuel cells on locomotives. Three important questions which have to be answered are:

1. Can the weight and volume requirement be accommodated? The volume of a phosphate cell system and its fuel is about 2600 ft$^3$, compared with 1600 ft$^3$ for a diesel/electric engine and its fuel. The weights and volumes of molten carbonate cells are not known at present.
2. Would the cells be adversely affected in performance by vibration, shocks, and tilting?
3. In the case of carbonate cells, operating at 1200°F, what problems of safety are there to be overcome?

## 7.5 DISCUSSION ON A FUEL-BY-FUEL BASIS

### 7.5.1 Coal

Two engines which have the capability to use coal are the steam engine and the Stirling. Both would become complicated and unwieldy if they were forced to meet emission standards comparable to those required on stationary boilers and furnaces.

The lowest investment that might be expected with either engine would be $300/HP, almost three times that of a diesel locomotive.

Both engines would continue to consume coal during idle periods. Whereas a diesel engine at idle consumes about 5% of its full power consumption, these coal burning engines are expected to burn at a rate 10% of full power.

The breakdown of costs for the horsepower year are as follows, on the basis of coal fuel at $1.23/MBtu.

| | $/HPY Coal Fired | | | |
|---|---|---|---|---|
| | Steam | | Stirling | |
| | Freight | Switching | Freight | Switching |
| Capital Recovery | 60 | 60 | 60 | 60 |
| Fuel | 51 | 21 | 26 | 10 |
| Maintenance | 6 | 7 | 6 | 7 |
| | 117 | 88 | 92 | 77 |
| D.F.B.E.C.* | 4.75 | 8.30 | 3.43 | 6.40 |
| B.E.I.C./$9** | 700 | 320 | 825 | 375 |

* The diesel fuel break-even cost (DFBEC) is the price of fuel in \$/MBtu at which a diesel engine is competitive with the prime mover/fuel combination under discussion. As an example, a Stirling engine (coal fired with \$300/HP capital) competes with diesel for freight hauling, any time the cost of diesel fuel rises above \$3.43/MBtu.

This means, that unless the diesel engine can obtain and operate on raw shale oil (the only candidate fuel in the \$3 price range), the Stirling could be viable for freight hauling.

** B.E.I.C./\$9 is the "Break Even Investment Cost" at which the prime mover/fuel combination competes with a diesel engine when diesel fuel reaches \$9/MBtu.

For example, this would happen if the only fuel available to a diesel engine were distillate at \$9/MBtu. In that case, the cost of a Stirling engine in freight hauling service could be allowed to rise to \$825/HP, far above the \$300/HP figure which has been used in this report. \$825/HP would give considerable allowance for air-pollution control equipment.

Both the Stirling and the steam engine owe whatever advantages they have to their ability to burn low cost coal, while it is assumed that their competitor, the diesel engine will not be able to burn coal. In switching, an operation which consumes little fuel, the overriding economic consideration becomes the capital investment, and the diesel engine remains competitive with the coal burning candidates almost up to the \$9/MBtu fuel price.

### 7.5.2 Coal/Oil Slurry

Again, two practical candidates for coal/oil slurry are the steam driven, and the Stirling locomotives.

It is possible that the diesel engine can be made to operate on coal/oil slurry though there would be no incentive to do that if a fuel like raw shale oil were available.

The breakdown of costs for coal/oil slurry consuming engines is as follows; with a coal/oil slurry cost of \$2.80/MBtu.

\$/HP Yr. - Coal/Oil Slurry

| | Diesel | | Steam | | Stirling | |
|---|---|---|---|---|---|---|
| | Freight | Switching | Freight | Switching | Freight | Switching |
| Capital | 21 | 33 | 60 | 60 | 60 | 60 |
| Fuel | 52 | 16 | 117 | 47 | 59 | 24 |
| Maint. | 8 | 8 | 6 | 7 | 6 | 7 |
| | 81 | 57 | 183 | 114 | 125 | 91 |
| DFBEC | \$2.80 | \$2.80 | \$8.30 | \$12.80 | \$5.00 | \$9.00 |
| BEIC/\$9 | \$743 | \$338 | \$370 | \$190 | \$660 | \$300 |

Several conclusions can be drawn from this table as follows:

1. if the diesel can be made to run on coal oil slurry, it outperforms both the candidates, steam and Stirling
2. if conventional diesel fuel rises in price to $9/MBtu, considerable money can be spent on diesel engine development to make it work on coal/oil slurry. In fact, a slurry burning diesel engine costing $743/HP would be viable
3. neither of the candidates can be considered for switching until conventional diesel fuel reaches the $9-$13/MBtu bracket
4. the Stirling option is better than the steam option and breaks even with conventional diesel fuel for freight hauling at $5/MBtu
5. an investment ceiling of $660/HP is available to the slurry fired Stirling if it is to compete with conventional diesel at $9/MBtu. However, under that circumstance, the solid coal fired Stirling option would be the better contender with an investment ceiling of $825/HP
6. if usable diesel fuel is available at $3/MBtu, there is no incentive for slurry in any of the engines.

### 7.5.3 Raw Shale Oil

This fuel establishes an important benchmark, because it is priced close to today's conventional diesel fuel price.

It seems likely that the locomotive diesel engine, which has been demonstrated to run on low grade liquid fuels such as distillate/residual petroleum blends and tar sand syncrude, could, with very little modification, be made to run successfully on raw shale distillate.

If so, and assuming the raw shale distillate can be made available for $3/MBtu, there is no combination of prime mover/alternate fuel which can beat the conventional diesel locomotive. This applies to both freight hauling (see Table 7-5) and to switching (see Table 7-6).

## 7.6 LIQUID FUELS AT PRICES OF $5/MBtu AND HIGHER

### 7.6.1 Freight Hauling

Table 7-3 illustrates the effect of rising fuel prices on each of the prime mover/fuel combinations.

Shale distillate, if available, at $4.90/MBtu would undoubtedly operate in today's conventional diesel locomotive, at an annual cost of $120 per horsepower year.

It has been observed already that the coal fired Stirling begins to become a serious potential contender, as liquid fuels approach this price (see $92/HPY).

Note also that the molten carbonate fuel cell has become viable at $110 running on shale distillate (which it may not be able to do), or at $117 if run on shale naphtha (which is a much more likely possibility).

In short, the conventional diesel engine begins to face serious contenders on two fronts as its own fuel rises toward $5/MBtu.

One pressure is from a relatively expensive engine, the Stirling, which can burn cheap coal. The other pressure is from an expensive engine burning expensive fuel, but at such high efficiency that it compensates.

As the price of fuels rise, the positions of the Stirling and the molten carbonate fuel cell improve. However, both these candidates represent undeveloped engines.

Between $5 and $9, the available fuels are naphthas which can be used in fuel cells and in gas turbines and which would call for modification of the diesel engine. (Probably conversion to a spark ignited engine.) At about $6/MBtu the phosphate fuel cell becomes viable. This system is much closer to commercialization than the molten carbonate cells are.

At $9/MBtu another important benchmark is reached, since at this price, coal distillate may become available and the conventional diesel engine can operate on it without modification.

Under this situation, (and only under this situation), the gas turbines, either simple cycle or regenerative, become definite leaders among the developed engines. Stated in other words, if the gas turbines can employ naphtha at $6.40/MBtu, while for some reason the diesel engine is restricted to fuel at $9/MBtu, the simple cycle FT wins by $7/HPY and the regenerative GT by $35/HPY.

At these fuel prices the phosphate fuel cell is beating the regenerative gas turbine by a further $14/HPY.

At these liquid fuel prices the coal fired steam locomotive has become a definite contender, and despite all the difficulties which have been mentioned regarding air pollution control, $700/HP could be spent on developing the coal fired steam locomotive if conventional diesel fuel rises to $9/MBtu. No more than $100 of that should be spent on condensing equipment, and only then if the peak efficiency can be raised to 28%.

## TABLE 7-3

## FREIGHT HAULING - TOTAL COSTS \$/HPY *

Numbers enclosed in boxes indicate technologies which are unlikely to be successful.

| | | | | | | | Fuel Cells | |
|---|---|---|---|---|---|---|---|---|
| Fuel Cost - \$/MBtu | Diesel | Steam | Stirling | GTS | GTR | Electric | $PO_4$ | $CO_3$ |
| 1.23 | $\boxed{52}$ | 117 | 92 | $\boxed{61}$ | $\boxed{67}$ | -- | $\boxed{81}$ | $\boxed{72}$ |
| 2.80 | $\boxed{81}$ | 183 | 125 | $\boxed{101}$ | $\boxed{96}$ | -- | $\boxed{102}$ | $\boxed{88}$ |
| 3.00 | 85 | 191 | 130 | $\boxed{106}$ | $\boxed{100}$ | -- | $\boxed{104}$ | $\boxed{90}$ |
| 4.90 | 120 | -- | -- | 153 | 135 | -- | $\boxed{129}$ | $\boxed{110}$ |
| 5.55 | 132 | -- | -- | 169 | 146 | -- | 137 | 117 |
| 6.40 | 148 | -- | -- | 190 | 162 | -- | 148 | 126 |
| 8.30 | 183 | -- | -- | 238 | 197 | -- | 173 | 146 |
| 9.00 | 197 | -- | -- | 255 | 210 | -- | 182 | 153 |
| 9.20 | 200 | -- | -- | 260 | 213 | -- | $\boxed{185}$ | $\boxed{155}$ |
| 9.50 | 206 | -- | -- | 268 | 219 | -- | 189 | 158 |
| 21.20 | 423 | -- | -- | 560 | 433 | -- | 340 | 281 |
| 14.90 | -- | -- | -- | -- | -- | 144 | -- | -- |

* All in \$ 1980.

## TABLE 7-4

## FREIGHT HAULING

### $/HP Capital Which Can be Justified to Develop Alternative Engines as a Function of Price of Conventional Liquid Diesel Fuel

| Lowest Price Diesel Fuel Available | Slurry/ Diesel(1) | Coal Diesel | Coal Steam | Coal Stirling | Gas Turbines | Electric Loco. | Fuel Cells $PO_4$ | Fuel Cells $CO_3$ |
|---|---|---|---|---|---|---|---|---|
| 3.00 | $\boxed{125}$ | $\boxed{270}$ | $\boxed{140}$ | $\boxed{265}$ | $\boxed{125}$ | $\boxed{20}$ | $\boxed{\text{None}}$ | $\boxed{69}$ |
| 4.90 | $\boxed{195}$ | $\boxed{445}$ | $\boxed{315}$ | 440 | $\boxed{125}$ | $\boxed{195}$ | $\boxed{167}$ | $\boxed{244}$ |
| 9.00 | 350 | 825 | 700 | 825 | $\boxed{135}$ | 580 | 552 | 629 |
| 21.20 | 800 | 1960 | 1830 | 1955 | $\boxed{150}$ | 1710 | 722 | 984 |

(1) Slurry fired diesel employing conventional liquid at stated price blended with 40% coal.

(2) Capital numbers in boxes are unlikely to be sufficient to promote development (e.g. gas turbines are in a borderline position vis-a-vis diesel engines, but a coal-fired Stirling engine becomes an attractive alternative once the diesel fuel cost rises above $5.

(3) Except for the following cases, the fuel/engine combinations shown in the headings are assumed to be competing with a diesel engine fueled by the lowest price fuel available.

Gas Turbines - use the same fuel as the diesel.

Fuel Cells - use synthetic naphtha ($6.40/MBtu) or ethanol ($21.20/MBtu).

It will also be noted that the electric locomotive has become viable as diesel fuel price passes $6/MBtu, though it will be remembered that no capital has been allowed yet for route electrification. When conventional diesel reaches $9/MBtu the breakeven situation for electric locomotive allows an extra investment of $265/HP which can be applied toward the installation of overhead lines. According to The Economist article (see Appendix 7-1) this would be more than enough to provide the service in a population concentration similar to that of Britain.

The annual operating cost for freight hauling as a function of fuel cost is given in Table 7-3.

Clearly, the prime mover which employs expensive fuels most effectively is the molten carbonate fuel cell though it would be beaten by:

1. a coal fired Stirling engine, if it could be developed for $630/HP
2. a coal fired steam engine if it could be developed for $500/HP
3. an electric locomotive, if it could be supplied with overhead lines for $70/HP. In a scenario, in which these fuels above $9/MBtu in price were the only ones available, there would be considerable pressure to develop the fuel cells, and if the diesel engine could not be converted to a spark ignited engine for less than $60/HP then the regenerative gas turbine would become the best choice among developed engines.

These complicated interactions have been summarized in Table 7-4 for the freight hauling locomotive. The numbers represent the dollars that could be spent to develop engines as the cost of running a conventional engine increases due to fuel price.

In order of effectiveness:

1. A coal fired diesel engine would be attractive even against today's fuel cost -- assuming it would keep its efficiency and maintenance costs the same as those of today's conventional engine
2. A coal fired Stirling locomotive is attractive starting at about $5/MBtu, and a carbonate fuel cell or slurry fired diesel engine are becoming viable at that price
3. At $9/MBtu, the fuel cells reach maximum attractiveness, but the coal fired steam locomotive becomes important too, and electrification should not be dismissed

4. If fuel cost $14/MBtu or more, a coal fired engine of any type must command great interest, and so must electrification. The fuel cells are still of interest.

Clearly, there is always going to be pressure to make the diesel engine work on whatever fuel is available at lowest cost. Given raw shale oil there is insufficient pressure to develop any other engine. If, for some reason (connected perhaps with the high nitrogen content of shale fuels), processing is required which brings the cost toward $5/MBtu, there would still be hardly enough pressure to develop other engines.

If direct coal fired engines are denied (perhaps again on grounds of inability to meet air pollution regulations, or for reasons of non-compatibility with the rail bridge systems) then the fuel cells, particularly the molten carbonate cell would be worthy of development.

### 7.6.2 Switching Locomotives

A similar comparison of the competitive situation for various switching locomotives is given in Tables 7-5 (total costs/HP year) and Table 7-6 (capital which can be justified as a function of conventional diesel fuel price).

The striking difference in the case of switching engines, is that there is much less pressure to look for replacements for the conventional diesel engine (i.e. capital justifiable for engine development is always much less than on Table 7-5).

For example, even when fuel reaches $9/MBtu, the advantage of the coal fired locomotives is only of the order $4-$15 per horsepower year. So, a new locomotive would have to be built for less than $375/HP to compete with a conventional diesel engine at $163/HP.

| | $ Annual Cost/HP Yr | |
|---|---|---|
| | Conventional Diesel Fuel at $9/MBtu | Stirling Engine Coal at $1.23/MBtu |
| Capital | 33 (20% of $165) | 75 (20% of $375) |
| Fuel | 51 | 10 |
| Maint. | 8 | 7 |
| | 92 | 92 |

The fuel cells become viable at somewhere between $6-9/MBtu. Electrification cannot be justified for switching until fuel for the diesel engine passes $14/MBtu.

## TABLE 7-5

## RAILROAD SWITCHING - TOTAL COSTS \$/HPY*

Numbers enclosed in boxes indicate technologies which are unlikely to be successful

| Fuel Cost - \$/MBtu | Diesel | Steam | Stirling | GTS | GTR | Electric | Fuel Cells $PO_4$ | Fuel Cells $CO_3$ |
|---|---|---|---|---|---|---|---|---|
| 1.23 | $\boxed{48}$ | 88 | 77 | $\boxed{52}$ | $\boxed{70}$ | -- | $\boxed{67}$ | $\boxed{60}$ |
| 2.80 | $\boxed{57}$ | 114 | 91 | $\boxed{61}$ | $\boxed{76}$ | -- | $\boxed{71}$ | $\boxed{63}$ |
| 3.00 | 58 | 117 | 92 | $\boxed{62}$ | $\boxed{77}$ | -- | $\boxed{72}$ | $\boxed{63}$ |
| 4.90 | 69 | 149 | 108 | 73 | 84 | -- | $\boxed{77}$ | $\boxed{68}$ |
| 5.55 | 72 | 160 | 114 | 76 | 87 | -- | 78 | 69 |
| 6.40 | 77 | 174 | 121 | 81 | 91 | -- | 81 | 71 |
| 8.30 | 88 | 206 | 137 | 91 | 98 | -- | 86 | 75 |
| 9.00 | 92 | 218 | 143 | 95 | 101 | -- | 88 | 76 |
| 9.20 | 93 | 221 | 145 | 96 | 101 | -- | $\boxed{88}$ | $\boxed{77}$ |
|  | 95 | 226 | 147 | 98 | 103 | -- | 89 | 78 |
| 21.20 | 163 | 422 | 246 | 163 | 149 | -- | 121 | 103 |
| 14.90 | -- | -- | -- | -- | -- | 114 | -- | -- |

* All cost in \$ 1980.

## TABLE 7-6

## SWITCHING

$/HP Capital Which Can be Justified to Develop Alternative Engines as a Function of Price of Conventional Liquid Diesel Fuel

| | Slurry Diesel(1) | Coal Diesel | Coal Steam | Coal Stirling | Gas Turbines | Electric Loco. | Fuel Cells $PO_4$ | Fuel Cells $CO_3$ |
|---|---|---|---|---|---|---|---|---|
| $3.00 | 168 | 213 | 150 | 205 | 205 | 209 | 186 | 203 |
| $4.90 | 193 | 268 | 205 | 260 | 225 | 264 | 240 | 258 |
| $9.00 | 258 | 383 | 320 | 375 | 255 | 379 | 356 | 373 |
| $21.20 | 395 | 738 | 460 | 515 | 370 | 734 | 511 | 568 |

(1) Slurry fired diesel employing conventional liquid at stated price blended with 40% coal.

(2) Capital numbers in boxes are unlikely to be sufficient to promote development (e.g. gas turbines are in a borderline position vis-a-vis diesel engines, but a coal-fired Stirling engine becomes an attractive alternative once the diesel fuel cost rises above $9.

(3) Except for the following cases, the fuel/engine combinations shown in the headings are assumed to be competing with a diesel engine fueled by the lowest price fuel available.

Gas Turbines - use the same fuel as the diesel.

Fuel Cells - use synthetic naphtha ($6.40/MBtu) or ethanol ($21.20/MBtu).

### 7.6.3 Special Case of Gas Turbines

The apparent lack of usefulness of gas turbines, is shown by a consistent low score on Tables 7-5 and 7-6. Yet, it is known that gas turbines have been used on fast passenger trains in several countries, and they were employed in freight service in the 1950s by Union Pacific.

The important point to note (from Tables 7-3 and 7-5) is that the gas turbines are never very much more costly on an annual horsepower basis, than the diesel engine running on the same fuel.

The following two examples will clarify this.

| | $/HP-Yr. | | | |
|---|---|---|---|---|
| | Switching (Fuel $4.90/MBtu) | | Freight (Fuel $4.90/MBtu) | |
| | Diesel | GT Simple | Diesel | GT Regen. |
| Capital | 33 | 40 | 21 | 40 |
| Fuel | 28 | 27 | 91 | 90 |
| Maint. | 8 | 5 | 8 | 5 |
| | 69 | 72 | 120 | 135 |

The engines have practically the same fuel consumption, the lower efficiency of the GT being balanced by the fuel it saves not idling. Maintenance for the gas turbines is half that for the diesel engines.

Therefore the slightly higher cost of the gas turbine horsepower year is a function of capital costs, which have been taken as follows in this study.

| | $/Horsepower at Wheel Motors | | |
|---|---|---|---|
| | Diesel | GT Simple | GT Regenerative |
| Freight Hauling | 105 | 133 | 200 |
| Switching | 163 | 200 | 300 |

The figures for diesel are based on the following prices.

| | Freight Hauling | Switching |
|---|---|---|
| Cost of engine and all electrical equipment needed to transmit power to wheel motors | $300 000 | $225 000 |
| HP of Engine | 3 265 | 1 625 |
| HP delivered to wheel motors | 2 850 | 1 380 |
| $/HP | 105 | 163 |

The price has been calculated on the actual HP available to the wheel motors, i.e. engine HP debitted by inefficiencies in the electrical conversion system and by the consumption of various locomotive auxiliaries.

Gas turbine engines are available in the size ranges needed for both these services. For example, the Army Tank Engine built by Avco Lyoming would serve the switching service but would almost certainly cost $300/HP minimum according to conversations with that supplier.(7-4)

## 7.7 OVERALL THERMAL EFFICIENCY FROM RESOURCE TO WHEEL MOTORS

Table 7-7 shows the overall thermal efficiency of many of the combinations of engines and fuels. The figures are in thousands of gross Btu of primary fuel (e.g. coal, shale, biomass, etc.) required to produce one horsepower hour (2547 Btu of work energy), taking into account all the energy lost in conversion to engine fuel, lost in transportation to the engine, and lost as reject heat at the engine itself, and in the electrical equipment which directs power to the wheel motors.

The figures were calculated using the following expression:

$$\underset{\text{(Mine to Shaft)}}{\text{Btu/HPh}} = \frac{2547}{E} \times F_1 \times F_2$$

$F_1$ = a factor relating the gross Btu of the engine fuel to its net Btu content. This is a function of the hydrogen content of the fuel and ranges from 1.18 for hydrogen to 1.02 for coal

$F_2$ = a factor relating the gross Btu content of the primary fuel at source to the gross Btu content of the resultant engine fuel delivered to the customer's tank. e.g. 1.82 Btu of coal at the mine are needed to produce 1.00 Btu of coal liquid at the engine

E = engine/alternator - rectifier efficiency taken as a combination of

0.29 x peak efficiency

0.29 x 1/2 load efficiency

0.42 x low power efficiency

| Engine | Efficiency E |
|---|---|
| Diesel | 0.31 |
| Steam | 0.15 |
| Gas turbine simple | 0.20 |
| Gas turbine regen. | 0.29 |
| Stirling | 0.29 |
| Electricity | 1.00 |
| $PO_4$ Fuel cell | 0.41 |
| $CO_3$ Fuel cell | 0.51 |

## TABLE 7-7

## OVERALL THERMAL EFFICIENCY FROM RESOURCE TO RAILROAD WHEELS

### k Btu/HPH Mine to Wheel Motors

|  | Diesel | Steam | Stirling | GT Simple | GT Regen. | Electric | Fuel Cells $PO_4$ | Fuel Cells $CO_3$ |
|---|---|---|---|---|---|---|---|---|
| Coal | 8.6 | 17.7 | 9.1 | -- | -- | -- | -- | -- |
| Coal/Oil Slurry | 9.8 | 20.2 | 10.3 | -- | -- | -- | -- | -- |
| Raw Shale | 9.7 | 20.1 | 10.3 | 14.6 | 10.3 | -- | -- | -- |
| Shale Dist. | 14.0 | -- | -- | 21.0 | 14.9 | -- | -- | -- |
| Shale Naph. | -- | -- | -- | 21.0 | 14.9 | -- | 10.5 | 8.5 |
| Coal Naph. | -- | -- | -- | 25.0 | 17.3 | -- | 11.9 | 9.6 |
| Coal Dist. | 15.8 | -- | -- | 23.8 | 16.8 | -- | -- | -- |
| Organic Oil | -- | -- | -- | -- | -- | -- | -- | -- |
| Methane | 17.1 | -- | -- | 25.7 | 18.2 | -- | 12.9 | 10.4 |
|  |  |  |  |  |  |  |  |  |
| Electricity | -- | -- | -- | -- | -- | 7.4 | -- | -- |

The $F_1$ and $F_2$ factors for the fuels are:

| | $F_1$ (Gross/Net) | $F_2$ (Mine Btu/fuel Btu) |
|---|---|---|
| Coal | 1.020 | 1.02 |
| Raw Shale | 1.065 | 1.11 |
| Coal/Oil Slurry | 1.040 | 1.14 |
| | | |
| Refined Shale | 1.068 | 1.59 |
| Coal Liquids | 1.055* | 1.82 |
| Methane | 1.125 | 1.85 |
| Electricity | 1.000 | 2.89 |

* 1.080 for coal derived gasoline.

For fuels having heat content in the range 18 000 Btu/lb factor $F_1$ is approximately 1 + 0.5 (percent $H_2$ ÷ 100). For other fuels, $F_1$ was derived from tables of net and gross heat content.

On this basis the highest efficiencies are obtained for the following combinations:

| | k Btu/HPH |
|---|---|
| Electric locomotive | 7.4 |
| Fuel cell/shale naphtha | 8.5 |
| Stirling/coal | 9.1 |

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7-2 The Economist, July 15, 1978, page 66 "Railways Go Electric."

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7-4 Telephone conversations with AVCO, Stratford, Conn. (October 1978).

7-5 Telephone conversations with Caterpillar, Aug. and Sept. 1978.

7-6 Foster, R. W. and W. J. D. Escher, "Hydrogen-Fueled Railroad Motive Power Systems, A Feasibility Study", EPA Report PR-70, Escher Technology Associates, St. Johns, Mich., September, 1976.

7-7 "Proceedings of the Fuel Cell Powered Vehicle Workshops", Los Alamos Scientific Laboratory, Los Alamos, N.M., August 15-17, 1977.

# 8. Aircraft

E. N. Cart, Jr.

## 8.1 Background

The U.S. aircraft industry can be divided into two basic areas - military and civilian. Within the civilian segment, the division is by certified route (passenger and cargo or all cargo), supplemental, and general aviation. The number of aircraft in each category in 1974 were as follows:

| | No. of Aircraft - 1974 |
|---|---|
| Certificated Route | |
| - Passenger/Cargo | 2,456 |
| - All Cargo | 62 |
| Supplemental | 100 |
| General Aviation | 145,000 |

Source - Ref. (8-1)

Within General Aviation, about 95 percent of the aircraft use piston engines, while in the certificated and supplemental categories over 93 percent of the aircraft use turbine engines.(8-1) A description of the different types of turbine engines in use and the types of fuels used by each type of engine is covered in Appendix Volume IIIA.

While General Aviation has by far the greatest number of aircraft, the fuel consumed represents about 6 percent of the total, as shown in Table 8-1, with half of this being jet fuel and half avgas. Since avgas represents a small fraction of the commercial market (4 percent) and the facilities are widespread, it would appear that substituting a different type of fuel in this market would be very difficult and costly. Therefore, this study will concentrate on jet fuel for the civilian market.

The amount of jet fuel used by the civilian sector represented 69 percent of the total consumed in 1976, with the military using 31 percent. On a total fuel consumed basis, jet fuel represented 95 percent of the volume used in 1976, based on the data in Table 8-1.

### 8.1.1 Commercial Aviation

Commercial aviation is a complex, capital and energy intensive system. In the non-communist world, about 83 percent of the commercial jet aircraft is U.S. built and 43 percent U.S. operated.(8-2) The chief stakeholders in the U.S. commercial aviation sector have been identified as follows:(8-2)

## Table 8-1

## U.S. Aircraft Fuel Usage - 1976

Million of Gallons

| | Jet | | Avgas | | Total | |
|---|---|---|---|---|---|---|
| | Vol. | % | Vol. | % | Vol. | % |
| **Civilian** | | | | | | |
| General Aviation | 495 | 3 | 432 | 57 | 927 | 6 |
| Air Carriers - Domestic | 7,822 | 54 | 20 | 3 | 7,842 | 52 |
| - International | 1,619 | 12 | - | | 1,619 | 11 |
| Total Civilian | 9,936 | 69 | 452 | 60 | 10,388 | 68 |
| **Military** | 4,515 | 31 | 300 | 40 | 4,815 | 32 |
| Total | 14,451 | 100 | 752 | 100 | 15,203 | 100 |
| % | 95 | | 5 | | 100 | |

Source: Ref. (8-25)

- Aircraft Manufacturers
  - Engine Manufacture
  - Airframe Manufactureres
- Airlines
- Airport Operators
- Fuel Producers and Distributors
- Government Regulatory Agencies
- Consumers

The military also has an influence on technology that is used in the civilian sector. Some pertinent factors on the first four stakeholders are pointed out below. A more detailed discussion is given in reference 8-2.

## Engine Manufacturers

There are two major U.S. producers of commercial aircraft engines - General Electric and Pratt and Whitney. Rolls-Royce is a foreign producer of commercial aircraft engines which are used on aircraft operating in the U.S. In 1975, around 850 jet engines were produced in the U.S., close to the average for 1970-1975, with the range being a high of 1040 in 1970 and a low of 565 in 1972.(8-3)

## Airframe Manufacturers

There are three major U.S. airframe manufacturers - Boeing, McDonnell-Douglas and Lockheed. A breakdown of aircraft production from 1970 to 1976 is given in Table 8-2. Between 200-300 aircraft have been produced per year from 1970-1976.

The development of new aircraft entails substantial economic risks. The development cost must be spread over the total number of planes to be sold and if the estimate of total planes to be sold is too optimistic, the airframe company must absorb part of the development cost. In addition, the long lead times (10-15 years) create cash flow problems and cumulative cash flow can be negative for this length of time.(8-2) Thus, the airframe manufacturers will be reluctant to "bet the company" on a radically different type of aircraft unless there are strong driving forces.

## Airlines

In the U.S. there were 33 airlines in 1972 in certificated routes.(8-1) (Intra-Hawaii and intra-Alaska carriers are excluded) Airlines can be characterized as both capital and energy intensive. It is assumed in the industry that the next generation of aircraft will have to offer airlines significant operational savings to gain acceptance.(8-2) Airlines will be interested in the following factors for future aircraft.(8-2)

## Table 8-2

## Commercial Aircraft Production

## 1970-1976

| | Production | | | | | | | Orders-12/31/76 | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 1970 | 1971 | 1972 | 1973 | 1974 | 1975 | 1976 | Total | U.S. | Foreign |
| **Wide Body** | | | | | | | | | | |
| 4 Engine | | | | | | | | | | |
| B 747 | 92 | 69 | 30 | 28 | 21 | 20 | 27 | 22 | 2 | 20 |
| 3 Engine | | | | | | | | | | |
| DC 10 | 0 | 13 | 52 | 57 | 46 | 43 | 19 | 27 | 3 | 24 |
| L 1011 | 0 | 0 | 17 | 39 | 41 | 25 | 16 | 70 | 38 | 32 |
| Total | 0 | 13 | 69 | 96 | 87 | 68 | 35 | 97 | 41 | 56 |
| **Regular Body** | | | | | | | | | | |
| 4 Engine | | | | | | | | | | |
| B 707 | 19 | 10 | 3 | 11 | 21 | 7 | 3 | 5 | 0 | 5 |
| DC 8 | 33 | 13 | 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 52 | 23 | 7 | 11 | 21 | 7 | 3 | 5 | 0 | 5 |
| 3 Engine | | | | | | | | | | |
| B 727 | 54 | 33 | 41 | 92 | 91 | 91 | 61 | 106 | 93 | 13 |
| 2 Engine | | | | | | | | | | |
| B 737 | 37 | 29 | 22 | 17 | 41 | 51 | 41 | 22 | 10 | 12 |
| DC 9 | 51 | 43 | 24 | 21 | 48 | 35 | 44 | 47 | 17 | 30 |
| Total | 88 | 72 | 46 | 38 | 89 | 86 | 85 | 69 | 27 | 42 |
| Fleet | 286 | 210 | 193 | 265 | 309 | 273 | 211 | 299 | 163 | 136 |

Source: Ref. (8-3)

- Initial Cost
- Energy Utilization
- Availability of Fuel
- Cost of Fuel
- Maintenance and Other Operating Costs
- Efficiency of Aircraft Turnaround on the Ground
- Labor Utilization
- Environmental Acceptability

New generations of airplanes in the past have been introduced at 10-12 year intervals.(8-2) With Boeing starting to introduce a new type of aircraft, this would imply the next generation will not be "due" till around 1990.

Airport Owners

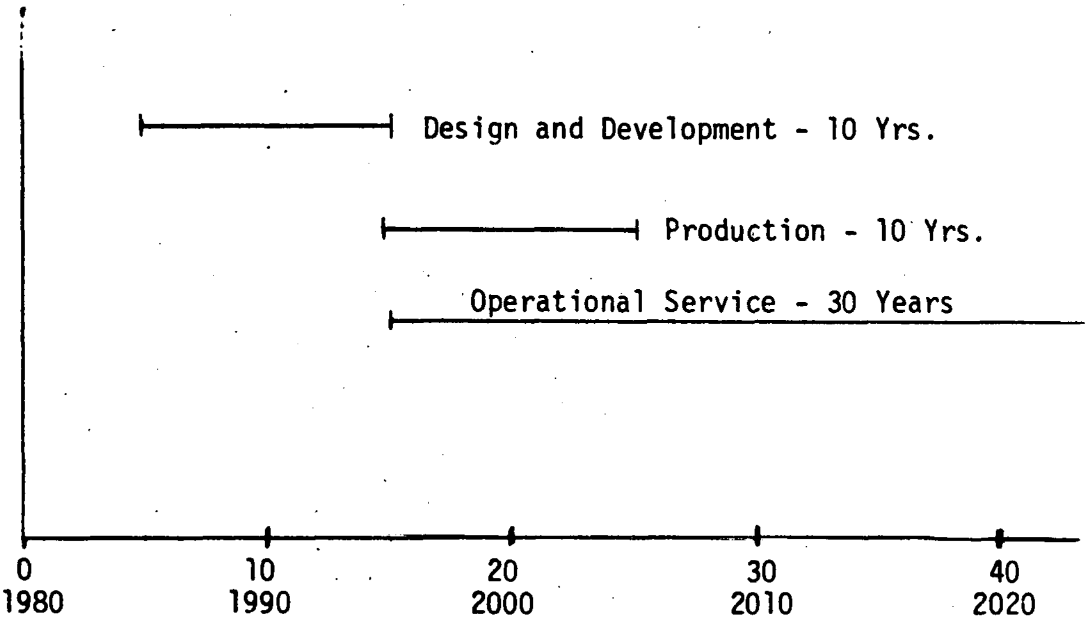
There were a total of 13,062 airport facilities in the U.S. at the end of 1974. Of this total, only 663 receive scheduled airlines. with only 26 of this total considered large hub airports.(8-1) The major airports are publicly owned and operated by municipal or regional governments. Airport construction is usually financed through the issue of revenue bonds, backed in part by the anticipation of landing fees to be collected from the airlines. These bonds would be competing with demands for cash for other social services, and it may be difficult for cities to install facilities that would be required for a cryogenic fuel. Use of a synthetic fuel could be more compatible with existing facilities.

Military

The military are generally the leaders in developing new aircraft and jet engines. Previous studies for DOD have identified that synthetic fuels, preferably from shale oil is their choice as a fuel to replace petroleum-based fuels.(8-18,8-7,8-15,8-32,8-33) If DOD does not develop a cryogenic fueled aircraft, the manufacturer's cost of development will rise since there would be no appreciable technology transfer.

### 8.1.2 Development, Production and Use Cycle of Advanced Transport Aircraft

The development, production and use cycle of advanced design transport aircraft is shown on the next page.



Source: Ref. (8-6)

Several points are evident from the above figure:

- If the decision to start the design and development of a cryogenic fueled aircraft is, say in 1985, the first aircraft to go into operational service would not be till around 1995. Since it would also take around ten years to develop the cryogenic facilities at the airports and the facilities to produce the fuel, in the case of liquid $H_2$, these decisions must also be made in 1985 to have fuel available for the operating aircraft.

- If the decision is made in 1980 to produce a new generation of airplanes using a petroleum or synthetic jet fuel, then a hydrocarbon type-jet fuel must remain available until 2020.

- Aircraft in use today must have a jet fuel that can be used in current engine design till around 2000.

- Thus, if a cryogenic fuel is introduced, dual fuel facilities will be required for the next 40 plus years!

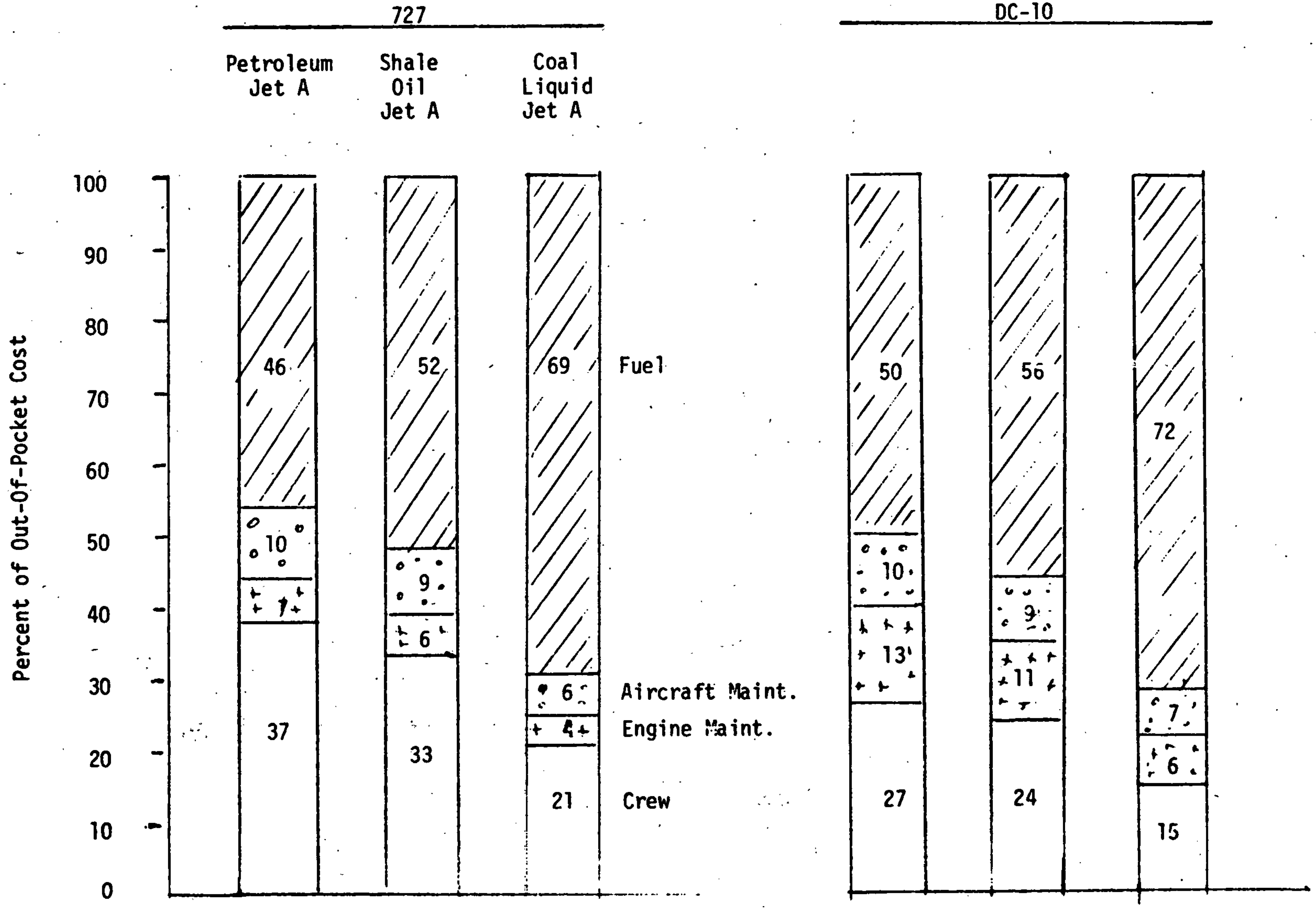
### 8.1.3 Turbine Aircraft Operating Cost

The distribution of 1976 out-of-pocket operating cost for two different aircraft, a 727 and a DC-10, is shown in figure 8-3. The petroleum fuel cost was 32¢/gal. in 1976. For both aircraft, fuel cost represented about half of the direct operating cost. If synthetic jet fuels, from shale oil or direct coal liquefaction, had been used, the fraction would have been greater, approaching about 70 percent in the case of coal liquids. In this case, air travel would be considerably more expensive, say 25 percent more. Hence, the amount of air travel, which to some degree, involves discretionary expenditures, would be less and fuel demand less. The cost of the shale and coal liquids used in this comparison is based on the values used in this study, deescalated to 1976 dollars at a 7 percent per year rate. Thus, fuel cost are a major consideration from the

Figure 8-1

Turbine Aircraft Operating Cost

1976 Out-Of-Pocket



Source: Ref. (8-4)

user's viewpoint. However, maintenance cost is also important, and it is recognized that there is a tradeoff between fuel cost and maintenance expense.(8-4)

## 8.2 Summary and Conclusions

- Based on the physical properties of the cryogenic fuels and the synthetic jet fuels considered, $LH_2$ has the highest heat of combustion on a weight basis, the highest specific heat (a measure of its efficiency as a coolant), but its disadvantages are its low density and resulting low volumetric heat content and its low boiling point.

- Liquid methane is 15 percent more energetic than jet A on a weight basis, has a specific heat 1.7 times that of jet A, and is six times more dense than liquid hydrogen.

- Studies by Lockheed have shown that for a subsonic, 5500 n. miles, 400 passengers aircraft, the initial cost of the aircraft would be about the same for all three fuels, $LH_2$, $LCH_4$ and jet A. The methane fueled aircraft characteristics fall between $LH_2$ and jet A. A $LH_2$ fueled aircraft design is lighter, uses less fuel for a given flight, requires an engine with lower thrust and requires a shorter runway.

- The fuel cost, on a per flight basis for a subsonic aircraft, shows that shale oil derived jet A would be the least costly, followed by coal liquid jet fuel. $LCH_4$ would cost about double a shale oil jet A. The $LH_2$ fueled aircraft would be the most expensive to operate -- over three times what a shale oil derived jet A would cost.

- Based on other studies by Lockheed, RAND, and Boeing, a synthetic jet fuel from shale oil would be the most economical fuel for future aircraft. Based on a life cycle comparison, the least costly is jet A from shale oil, followed by jet A from coal, with $LCH_4$ next and $LH_2$ the most expensive.

- For a supersonic aircraft (Mach 2.7, 4200 n. miles, and 234 passengers), the design advantages for $LH_2$ are greater than for a subsonic aircraft. However, the fuel cost perflight still favors the jet A case, (shale oil first, followed by coal derived jet fuel) then $LH_2$.

- For supersonic aircraft, the cost of a jet A fueled aircraft has been estimated to be about 35 percent higher than a $LH_2$ fueled aircraft. Including the cost of the aircraft and the potentially lower maintenance cost makes $LH_2$ more attractive than the subsonic case, but still a shale oil derived jet A would be the preferred fuel, with a coal derived fuel next.

- For subsonic aircraft $LH_2$ would have to cost about 47 percent less than value used in this study to breakeven with a coal derived jet A and 71 percent less to breakeven with a shale oil based jet A on a fuel cost per flight. For a supersonic aircraft the cost of $LH_2$ would have to be 17 percent less than the value used in this study to breakeven with a coal-derived jet fuel and 45 percent less to breakeven with a shale oil derived jet fuel, considering the difference in the cost of the aircraft as well as the fuel cost difference.

- Liquid $H_2$ aircraft would appear to only be attractive for very long subsonic flights (>5500 miles) and for supersonic flights at greater than mach 2.7.

- From the standpoint of natural resource requirements, considering the resources required from the mine to that used to power the aircraft, a shale oil derived jet fuel is the most efficient. $LH_2$ requires about double the amount of natural resource as shale oil.

- Lab tests have shown that acceptable jet fuels can be made from either coal or shale oil based resources. Production of aircraft fuels from shale oil should be more straight forward than from coal.

- Coal based jet fuels will have poorer combustion properties than shale oil due to the formation of naphthenes rather than paraffins when the coal liquids are hydrogenated.

- An economic comparison between upgrading fuels to meet current hydrogen levels and modifying the engine shows that there are incentives to develop an engine that can accept a poorer quality fuel. If a 12 percent hydrogen content fuel can be used, the incentive would be about 170k$/year per engine to use an engine that can handle a fuel with a lower hydrogen content.

- In addition to changing the specification to allow a lower hydrogen content fuel to be used, the boiling range of the jet fuel fraction could also be changed to increase the potential availability of jet fuel from a given barrel of liquid feedstock. This increase would be at the expense of home heating oil, chemical feedstock or diesel fuel and gasoline. Two properties affected by this change would be the flash point and the freeze point.

- Modifications to existing aircraft system to handle a higher freeze point fuel (0°F freeze point) would be very small, generally less than 1¢/gallon.

- Ground handling modifications to handle a higher freeze point jet fuel could be made for a minimal cost, like 0.01 ¢/gal of fuel handled.

- In the near term, it is unlikely that there will be any major changes in the specifications of commercial jet fuels. There may be minor changes to increase supplies if another embargo develops In the mid term, 1985-2000, a broad cut fuel may be used, depending on the outcome of the current NASA efforts in this area. By 1990, it is possible that a shale oil derived fuel may be used to a limited extent in commercial operation. Aircraft designed to utilize synthetic jet fuels are not likely till around 2000. The major replacement of petroleum based jet fuel in the long term (2000-2025) is most likely to be shale oil derived jet fuel, with some coal liquids from indirect liquefaction possible. It is unlikely that $LH_2$ or $LCH_4$ will be widely used in commercial aviation, unless there is a strong demand for long distance supersonic flights.

## 8.3 Comparison of Cryogenic and Synthetic Jet Fuels

The types of future aircraft fuels for jet engines can be directed into general categories.

| Synthetic Jet Fuels | Cryogenic |
|---|---|
| Shale Oil Distillate | Liquid $H_2$ |
| Coal Liquid Distillate<br>+ Direct Liquefaction<br>+ Indirect Liquefaction | Liquid $CH_4$ |
| Tar Sands (outside U.S.) | |
| Heavy Crudes (outside U.S.) | |

In this section the properties of these fuels will be compared, the cost of operating both a subsonic and a supersonic aircraft will be compared for the various fuels, and the resource requirements for each case will be considered.

### 8.3.1 Comparison of Properties

Some of the properties of the alternate fuels are shown in Table 8-3. As can be seen $LH_2$ has the highest heat of combustion on a weight basis, a measure of its energy content, and the highest specific heat, indicating its capability for use as a coolant. On a volume basis, the heat content of $LH_2$ is 25 percent of that of synthetic jet fuel, meaning that more storage volume is required for a given flight. Another disadvantage for $LH_2$ are its low density and its low boiling point. Methane is 16 percent more energetic than jet A on a weight basis but only 42 percent as energetic as hydrogen. Its specific heat is 1.71 times that of jet A but a third of that of hydrogen. $LCH_4$ is roughly half as dense as jet A but six times as dense as liquid hydrogen. It is classified as a mild cryogenic liquid compared to liquid hydrogen. $LCH_4$ and $LH_2$ should produce less noxious products than conventional aircraft fuel.

### 8.3.2 Cost Comparison

#### 8.3.2.1 Subsonic Aircraft

One of the more recent studies currently in progress for NASA is a comparison between liquid hydrogen ($LH_2$), liquid methane ($LCH_4$) and jet A. This study is being conducted by Lockheed - California, as the prime contractor. The purpose of the study was to define a preferred configuration for a $LCH_4$ fueled aircraft (400 passengers, 5500 n miles flying at 0.85 mach no.) to determine the characteristics of the ground facilities required, to compare LCH4 aircraft to $LH_2$ and jet A, and to outline technology development required for a $LCH_4$ fueled aircraft. It was assumed initial operation capability would be 1990-1995. The engine characteristics assumed for this study are shown in Table 8-4. Lockheed has concluded that the preferred fuel storage design for $LCH_4$ and $LH_2$ aircraft would be to have the fuel in the fuselage. The summary comparison of $LH_2$ and $LCH_4$ and jet A is shown in Table 8-5. The methane aircraft characteristics fall between $LH_2$ and jet A.

## Table 8-3

## Properties of Possible Alternate Jet Fuels

| | Synthetic Jet | | Methane | Hydrogen |
|---|---|---|---|---|
| | Shale | Coal | | |
| Heat of Combustion<br>- BTU/lb<br>- BTU/Gal | <br>18,500*<br>122,700* | <br>18,400-18,500*<br>123 -124,000* | <br>21,500<br>80,000 | <br>51,600<br>30,600 |
| Liquid Density lb/FT$^3$ @ 60°F** | 51 | 51 | 27.9 | 4.4 |
| Boiling Point (°F) at 1 Atmosphere | 400 to 550 | | -259 | -423 |
| Freezing Point -°F | -58 | -90 | -296 | -435 |
| Specific Heat BTU/lb °F | 0.48 | | .822 | 2.29 |
| Heat of Vaporization BTU/lb @ Normal Boiling Point | 105* | 110* | 219 | 194 |

** At Boiling Point
* Estimated Value

## Table 8-4

## Baseline Engine Characteristics

SLS, Uninstalled

Standard Day

| | $LH_2$ | $LCH_4$ | JET A |
|---|---|---|---|
| POWER SETTING | TAKEOFF | TAKEOFF | TAKEOFF |
| NET THRUST (LB) | 30,706 | 30,706 | 30,706 |
| SFC $\frac{(LB/HR)}{LB}$ | 0.1025 | 0.2460 | 0.2874 |
| BYPASS RATIO | 10.25 | 10.25 | 10.25 |
| FAN AIR FLOW LB/SEC | 1070 | 1070 | 1070 |
| COMPRESSOR PRESSURE RATIO | 15.5 | 15.5 | 15.5 |
| TURBINE INLET TEMP, °F | 2700 | 2700 | 2700 |

Source: Ref. (8-5)

## Table 8-5

### Comparison of LH$_2$, Methane and Jet A Aircraft

5500 N. Miles, 0.85 Mach. No., 400 Passengers

| | | LH$_2$ | METHANE CONFIGURATION 1 | JET A |
|---|---|---|---|---|
| GROSS WT | LB | 372,205 | 493,900 | 511,600 |
| TOTAL FUEL | LB | 56,457 | 152,200 | 186,900 |
| BLOCK FUEL | LB | 47,666 | 129,000 | 159,900 |
| OEW | LB | 227,748 | 253,600 | 236,700 |
| WING AREA | FT$^2$ | 3,195 | 4,490 | 4,093 |
| SPAN | FT | 170 | 201 | 192 |
| FUSELAGE LENGTH | FT | 215.6 | 201.3 | 197 |
| SFC | | 0.202 | 0.492 | 0.603 |
| L/D CRUISE | | 17.4 | 19.1 | 19.13 |
| WING LOADING PSF | | 116.5 | 110.0 | 125 |
| T/W | | 0.326 | 0.300 | 0.325 |
| THRUST PER ENGINE | LB | 30,350 | 37,040 | 41,600 |
| FAR T.O. DIST | FT | 8,006 | 7,804 | 7,976 |
| FAR LDG DIST | FT | 5,799 | 5,001 | 5,197 |
| APPROACH SPEED KNOTS | | 138 | 124 | 127 |
| PRICE – MILLIONS | | 43.39 | 47.45 | 44.53 |

Source: Ref. (8-5)

It is interesting to calculate the thermal efficiency for the three fuels, based on an assumed speed of 550 MPH. These efficiencies are as follows:

$LH_2$ - 36 percent

$LCH_4$ - 35 percent

Jet A - 34 percent

These efficiencies are for a 2700°F turbine inlet temperature.

The cost of operation with these three fuels is summarized in Table 8-6, based on the cost data developed in this study. The jet A cost are shown for a shale oil based fuel, and two coal derived fuels, a fuel produced from a direct liquefaction process, and one from an indirect coal liquefaction process. The comparison is shown per flight, so the ratio is more meaningful. As shown, the shale oil derived jet A would be the least costly, followed by the coal liquids. $LCH_4$ falls in the upper range for the coal liquids. The $LH_2$ fueled aircraft would be the most expensive, over three times what a shale oil derived jet A fuel would cost.

Several other studies have also been made for subsonic aircraft comparing $LH_2$, $LCH_4$ and synthetic jet fuel. The results of the studies are summarized below.

### 8.3.2.1.1 Lockheed Study(8-6)

The aircraft design was for a 400 passenger airplane designed to cruise at mach 0.85 with a range capability of 5500 n. miles. The liquid hydrogen would be stored in the fuselage, both aft and forward of the passenger compartment. A comparison of several key parameters for a $LH_2$ aircraft and a jet A fueled counterpart is shown in Table 8-7. It can be noted that the $LH_2$ design is lighter, uses less fuel for a given flight, requires an engine with lower thrust because of the lighter weight and requires a shorter runway. The two aircraft are estimated to cost about the same.

The basic reason for the superiority of the $LH_2$ design stems primarily from the lift-to-drag ratio in cruise (a negative factor) and the specific fuel consumption (a positive factor). Even with the favorable design factors for a $LH_2$ aircraft, it still would not be economical to operate as a jet A type aircraft, based on the cost of fuels developed in this study, as shown in Table 5-8. Fuel cost for a jet A fuel made from shale oil would be about a third of that for the $LH_2$ fueled aircraft, while a jet fuel from a direct coal liquefaction process would have about half the fuel cost of the $LH_2$ aircraft.

## Table 8-6

### Comparison of Cost of Fuel for Cryogenic and Synthetic Jet Fuels

### Fuel Consumption Based on Table 8-5 Subsonic Flight

<table>
<tr><th rowspan="2"></th><th rowspan="2">LH2</th><th rowspan="2">LCH4</th><th colspan="3">Jet A</th></tr>
<tr><th>Shale</th><th>Direct Coal</th><th>Indirect Coal</th></tr>
<tr><td>Block Fuel Usage</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Lbs</td><td>47,666</td><td>129,000</td><td colspan="3">159,900</td></tr>
<tr><td>BTU x $10^9$</td><td>2.46</td><td>2.77</td><td colspan="3">2.93</td></tr>
<tr><td>Fuel Cost @ Airport $/MBTU</td><td>16.7-19.2</td><td>9 -12.6</td><td>4.9-5.1</td><td>5.9-9.7</td><td>6.5-12.7+</td></tr>
<tr><td>Fuel Cost/Flight $ x $10^3$</td><td>41 -47.2</td><td>25-35</td><td>13.8-15</td><td>17.3-28.4</td><td>18.9-37</td></tr>
<tr><td>Ratio of Fuel Cost</td><td>2.97-3.15</td><td>1.8-2.33</td><td>1.0</td><td>1.25-1.89</td><td>1.37-2.47</td></tr>
</table>

Table 8-7

Comparison: $LH_2$ and Jet A Subsonic Transport Aircraft

(Mach 0.85, 5500 N. Mi. 400 Passengers)

| | | $LH_2$ | Jet A | Ratio $\left(\frac{\text{Jet A}}{LH_2}\right)$ |
|---|---|---|---|---|
| Gross Weight | lb | 391,700 | 523,200 | 1.34 |
| Operating Empty Weight | lb | 242,100 | 244,400 | 1.01 |
| Block Fuel Weight | lb | 52,900 | 165,500 | 3.13 |
| Thrust Per Engine | lb | 28,700 | 32,700 | 1.14 |
| Wing Area | $ft^2$ | 3363 | 4186 | 1.24 |
| Span | ft | 174 | 194.1 | 1.12 |
| Fuselage Length | ft | 219 | 197 | 0.90 |
| Field Length Required | ft | 6240 | 7990 | 1.28 |
| Lift/Drag (Cruise) | - | 16.07 | 17.91 | 1.12 |
| Specific Fuel Consumption (Cruise) | $\frac{lb}{hr}/lb$ | 0.199 | 0.581 | 2.92 |
| Aircraft Price | $\$10^6$ | 26.9 | 26.5 | 0.99 |
| Energy Utilization | $\frac{Btu}{seat\ nmi}$ | 1239 | 1384 | 1.12 |
| Noise, Sideline | EPN dB | 87.2 | 87.8 | - |
| Flyover | EPN dB | 89.2 | 94.2 | - |

Source: Ref. (8-6)

## Table 8-8

## Comparison of Cryogenic Fuels and Synthetic Jet Fuels

## Fuel Usage Based on Data in Table 8-7

Subsonic Aircraft - Mach 0.85, 5500 N. Mi., 400 Passengers

| | Jet A | | $LH_2$ |
|---|---|---|---|
| | Coal | Shale | |
| K$/Flight | 17.9-29.4 | 14.9-15.5 | 45.6-52.4 |
| Ratio To Shale Derived Fuel | 1.2-1.9 | 1 | 3.1-3.4 |

In addition to fuel cost, the return on investment, maintenance and other direct operating cost would have to be considered. In the case of subsonic aircraft, the cost of the aircraft are shown to be about the same so that fuel cost would be the prime consideration.

### 8.3.2.1.2 Life Cycle Cost

Two other studies, one by RAND and the other by Boeing compared the three fuels using a life cycle cost comparison. RAND has made a study for the Air Force on evaluating alternate fuels for very large airplanes (VLA), defined as a plane with a gross weight in excess of one million pounds.(8-7) Candidates for application of VLA include strategic airlift, tankers, missile launcher, and maritime air cruisers. Design consideration were a design radius of 3600 n. mi., without refueling at the destination, cruise mach. number of .75 - 0.8 and a takeoff critical field length of 8000 ft. and a design payload of 350,000 lbs. The four fuels considered were coal derived jet A (direct liquefaction), $LCH_4$, $LH_2$ and nuclear. The conclusion from this study was that overall, a conventional hydrocarbon jet fuel (derived from oil shale, or coal) remains the most attractive fuel for military aircraft. Liquid hydrogen and liquid methane will offer little potential as military fuels until U.S. oil shale, and coal resources are approaching exhaustion. Nuclear propulsion for aircraft was only attractive for station-keeping mission requiring large station radii.(8-7)

Several factors are of potential interest in this study. First, the propulsion parameters for the various alternate fuels, shown in Table 8-9, allows one to calculate a thermal efficiency for an assumed plane speed. At 550 MPH, the efficiency used was essentially the same for all fuels - at 32 percent as shown below.

JP - 32.7 percent

$LCH_4$ - 32.0 percent

$LH_2$ - 31.5 percent

The overall efficiency is lower than the Lockheed study, since the turbine inlet temperature is 2500°F, compared to 2700°F in the Lockheed study.

The second interesting comparison is the estimated life-cycle cost for the various fuels. While the comparison is sensitive to the number of aircraft procured and number of flying hours per year, the comparison, shown in Table 8-10, shows the Jet A fuel more attractive. The fuel cost used in this comparison are based on the estimates in this study deescalated to 1975 dollars. With shale oil, there is even a greater delta between the jet A and $LH_2$.

## Table 8-9

## Aerodynamic and Propulsion Parameters for the Alternative Airplanes

| Parameter | C-5B | VLA-JP | VLA-$LCH_4$ | VLA-$LH_2$ |
|---|---|---|---|---|
| **Aerodynamic Data** | | | | |
| Cruise Mach number | 0.77 | 0.75 | 0.75 | 0.75 |
| Initial cruise altitude (ft) | 30,000 | 30,000 | 30,000 | 30,000 |
| Zero-lift drag coefficient | 0.0178 | 0.0148 | 0.0151 | 0.0180 |
| Lift-to-drag ratio (maximum) | 20.0 | 21.6 | 21.4 | 18.6 |
| **Propulsion Data** | | | | |
| Number of engines | 4 | 6 | 6 | 6 |
| Bypass ratio | 8 | 10 | 10 | 10 |
| Fan pressure ratio | 1.42 | 1.40 | 1.40 | 1.40 |
| Overall pressure ratio | 25 | 35 | 35 | 35 |
| Turbine inlet temperature (°F) | 2,380 | 2,500 | 2,500 | 2,500 |
| At max. sea level static power | | | | |
| - Installed thrust | 39,100 | 81,500 | 83,400 | 56,400 |
| - Installed TSFC[6] (lb/hr/lb) | 0.333 | 0.296 | 0.257 | 0.109 |
| Cruise TSFC (lb/hr/lb) | 0.675 | 0.624 | 0.542 | 0.230 |

[a] For operation on JP, unless otherwise noted.

[b] Thrust specific fuel consumption.

Source: Ref. (8-7)

## Table 8-10

## Life Cycle Costs For Various Alternate Aircraft Fuels

(Billions of 1975 dollars, unless noted)

| | Jet A | | $LCH_4$ | $LH_2$ |
|---|---|---|---|---|
| | Coal | Shale | | |
| Procurement | 11.9 | 11.9 | 12.7 | 10.4 |
| RDT&E | 3.6 | 3.6 | 3.9 | 3.2 |
| 20 Yr. O&S ex fuel | 12.8 | 12.8 | 13.6 | 11.5 |
| Fuel @ 2650 hr & our cost data | 27.3 | 14.8 | 30.6 | 49.9 |
| | 55.6 | 43.1 | 60.8 | 75.0 |

Notes:

1. Number of aircraft procured - 129
2. Unit Flyaway Cost - Millions of 1975 Dollars

| | |
|---|---|
| Jet A | $79.2 |
| $LCH_4$ | 84.5 |
| $LH_2$ | 69.0 |

3. Cost includes avionics, ground support, equipment, initial spares, etc.
4. Fuel cost based on 2650 hrs./yr. flying time and fuel cost of (1975 dollars) as follows

| | |
|---|---|
| Jet - Coal Liquids | $6.46/M BTU |
| $LCH_4$ | 6.79 |
| $LH_2$ | 13.39 |

Source: Ref. (8-7)

Boeing has reported on a study made for the Air Force on the conceptual design and evaluation of military heavy logistics transport aircraft.$^{(8-8)}$ Design payloads were 200-600,000 lbs. and design ranges of 3600-7200 nm. at subsonic speeds (0.70.8 mach number). The resulting aircraft designs have takeoff gross weights of 1.5 million pounds. A 20 year life cycle cost was projected for jet A fuel, $LCH_4$ and $LH_2$. Two methods were used to arrive at the airframe and engine costs. One method used the Rand Cost Models, the other using a Boeing cost model. It was assumed that one developmental airplane for each design was procured. A 250 airplane buy was assumed and the utilization rate was taken at 1000 hours/year, which is low for commercial operations. The range was 6200 n miles, payload set at 400,000 lbs. and cruise speed at 0.8 mach at 36,900 feet. The resulting gross weight of the design and engine thrust for the two was as follows:

| | JP | $LCH_4$ | $LH_2$ |
|---|---|---|---|
| Take Off Gross Weight - lb x $10^3$ | 1,480 | 1,800 | 1,225 |
| Engines - | | | |
| No. | 4 | 6 | 4 |
| Thrust SLST | 81,800 | 66,300 | 67,700 |

A comparison of the life cycle cost for the Boeing design basis is summarized in Table 8-11. The most attractive alternate was the JP type, followed by $LCH_4$, with $LH_2$ the least cost effective. The fuel cost shown are the ones used by Boeing; they have not been adjusted to the values used in this study.

### 8.3.2.2 Supersonic Aircraft

Lockheed has made a comparison between $LH_2$ and jet A from coal liquids for a mach 2.7 SST capable of carrying 234 passengers, 4200 n. mi.$^{(8-6,8-9)}$ A comparison of the $LH_2$ and jet A fueled aircraft is shown in Table 8-12. The advantages for the $LH_2$ SST is greater in nearly every instance to the subsonic $LH_2$ version. This is attributable to the supersonic aircraft requiring more fuel and $LH_2$ is a higher energy content fuel. However, the economics still favor the jet A case, as shown in Table 8-13. As shown by the comparison to the subsonic data, the supersonic $LH_2$ aircraft does appear to be more attractive. However, to breakeven with coal derived jet fuel, the $LH_2$ cost would have to be reduced from \$18.75/ MBTU to \$12.43/ MBTU and to breakeven with a shale oil derived jet fuel, the $LH_2$ cost would have to be reduced to \$6.73 - or half of the projected cost. This does not appear likely.

Very little information was found in the literature that compared $LH_2$, $LCH_4$ and synthetic jet A for supersonic aircraft. One comparison was given in a report by NASA$^{(8-38,8-39)}$. Table 8-14 summarizes some of the pertinent design comparisons. Using the cost of fuels developed in this study, a comparison between the various fuels is shown in Table 8-15. Shale oil based synthetic jet A would be the most economical, with $LCH_4$ and coal liquids (direct) about the same. $LH_2$ would be about three times more expensive. This comparison does not take into account any potential savings in the cost of the aircraft, as reported by Lockheed.$^{(8-8,8-9)}$

Table 8-11

Comparison of Life Cycle Cost for Possible Future Aircraft Fuels

Payload - 400,000 lbs

Range - 6200 miles

1985 Technology

FY 1976 Dollars

| | JP - Coal Liquid | $LH_2$ | $LCH_4$ |
|---|---|---|---|
| Procurement | 18.9 | 19.9 | 25.3 |
| Development | 2.8 | 2.9 | 3.4 |
| Support Investment | 2.8 | 3.0 | 3.8 |
| Operations & Support | | | |
| ex Fuel | 11.52 | 11.42 | 13.0 |
| Fuel(1) | 9.45 | 30.07 | 16.09 |
| TOTAL | 45.40 | 67.20 | 61.70 |

(1) Fuel cost are <u>not</u> the same as used in this study.

Source: Ref. (8-8)

## Table 8-12

### Comparison: $LH_2$ and Jet A Supersonic Transport Aircraft

### (Mach 2.7, 4200 n. mi., 234 Passengers)

|  |  | $LH_2$ | Jet A | Ratio $\left(\frac{\text{Jet A}}{LH_2}\right)$ |
|---|---|---|---|---|
| **Gross Weight** | **lb** | 394,900 | 762,200 | 1.93 |
| **Operating Empty Weight** | **lb** | 245,200 | 317,400 | 1.29 |
| **Block Fuel Weight** | **lb** | 85,390 | 330,500 | 3.88 |
| **Thrust per Engine** | **lb** | 52,820 | 86,890 | 1.64 |
| **Wing Area** | **$ft^2$** | 7952 | 11,094 | 1.39 |
| **Span** | **ft** | 113 | 133.5 | 1.18 |
| **Fuselage Length** | **ft** | 340.2 | 297 | 0.87 |
| **Field Length Required** | **ft** | 7800 | 9490 | 1.22 |
| **Lift/Drag (Cruise)** | **--** | 7.42 | 8.65 | 1.17 |
| **Specific Fuel Consumption (Cruise)** | **$\frac{lb}{hr}/lb$** | 0.575 | 1.501 | 2.61 |
| **Aircraft Price** | **$\$10^6$** | 45.5 | 61.5 | 1.35 |
| **Energy Utilization** | **$\frac{Btu}{seat\ nmi}$** | 4483 | 6189 | 1.38 |
| **Noise, Sideline** | **EPNdB** | 104.0 | 108.0 | - |
| **Flyover** | **EPNdB** | 102.2 | 108.0 | - |
| **Sonic Boom Overpressure** | **$lb/ft^2$** | 1.32 | 1.87 | 1.41 |

Source: Ref. (8-6)

## Table 8-13

## Comparison of Fuel Cost for Various Alternate Aircraft Fuels - Supersonic Flight

Mach 2.7, 4200 N. Mi., 234 Passengers

| | Jet A | | $LH_2$ |
|---|---|---|---|
| | Coal | Shale | |
| K$/Flight For Fuel | 37.8-58.8 | 29.7-30.8 | 73.7-84.7 |
| Ratio To Shale Derived Fuel | 1.3-1.9 | 1 | 2.5-2.7 |

Fuel Usage From Table 8-12

## Table 8-14

## Supersonic Aircraft Study

### 4000 N. Mi., 2.7 Mach No., 250 Passengers

| | Syn. Jet A | $LCH_4$ | $LH_4$ |
|---|---|---|---|
| Gross Weight, K Lbs. | 842 | 765 | 504 |
| Span, ft. | 156 | 148 | 120 |
| Fuselage Length, Ft. | 322 | 319 | 358 |
| Block Fuel, K Lbs. | 331 | 252 | 100 |

Source: Ref. (8-38)

## Table 8-15

## Supersonic Aircraft

| | Syn. Jet A | | LCH$_4$ | LH$_2$ |
|---|---|---|---|---|
| | Shale | Coal Direct | | |
| Fuel Cost - Airport $/MBTU | 4.7-5.1 | 5.9-9.7 | 9-12.6 | 16.7-19.2 |
| Fuel Cost/Flight -K$ | 29-31 | 36-59 | 49-68 | 86-99 |
| Relative | 1 | 1.24-1.9 | 1.69-2.2 | 3.0-3.2 |
| Fuel Resource Req Relative | 1 | 1.13 | 1.08 | 2.07 |

## Table 8-16

## Supersonic Aircraft Comparison

- 400 Flights/Yr
- Investments & Fuel Usage Per Lockheed Study

| | Annual Cost - $M | | | |
|---|---|---|---|---|
| | Syn. Liquids | | | |
| | Shale Oil | Coal | | $LH_2$ |
| | | Direct | Indirect | |
| Fuel | 11.4-12.4 | 14.3-23.5 | 15.7-30.7 | 29.4-33.8 |
| Investment | 19.8 | 19.8 | 19.8 | 14.4 |
| Total | 31.2-32.2 | 34.1-43.3 | 35.5-50.5 | 43.8-48.2 |
| Ratio | 1 | 1.1-1.34 | 1.14-1.57 | 1.40-1.50 |

In the case of supersonic aircraft, Lockheed has estimated an investment advantage for the $LH_2$ aircraft which has to be considered. If the cost of the aircraft are included, as well as any maintenance cost advantages, then $LH_2$ becomes more attractive if compared to coal liquids. However, if the comparison is made to the cost of shale oil liquids, then even including the difference in cost between the jet A and $LH_2$ aircraft wouldnot appear to be enough to make $LH_2$ aircraft attractive. This comparison is shown in Table 8-12.

Another advantage for $LH_2$ in supersonic flight is that much longer ranges are possible than for jet fueled aircraft, due to the higher energy density of $LH_2$. As shown in Figure 8-2, the ratio of gross takeoff weight for $LH_2$ vs. jet fuel for a supersonic aircraft is 1.76 at 4200 mile range and 2.66 for a 5500 mile range. Thus, $LH_2$ would offer its greater performance advantage in supersonic flight over long ranges, such as transpacific flights.

Such aircraft would have to be dedicated to this service and there would be no backup planes that could be used. Moreover, $LH_2$ would have to be available at non-U.S. transpacific loactions and the airlines flying the $LH_2$ planes would be at the mercy of prices charged by local suppliers of $LH_2$.

### 8.3.2.3 Comparison of Subsonic and Supersonic Aircraft with $LH_2$ and Jet A

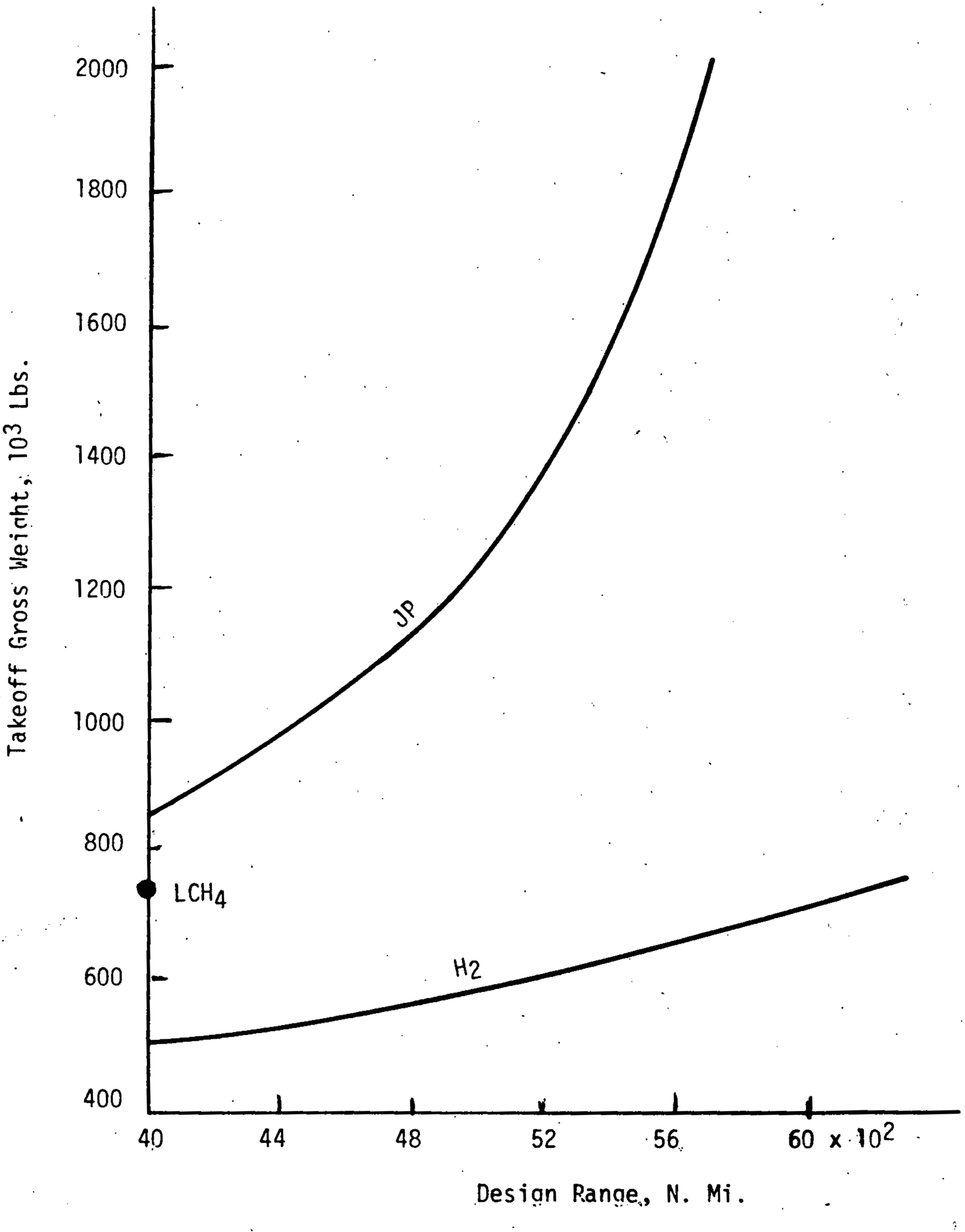
A comparison between the cost of fuel used for a subsonic and a supersonic aircraft for varying $LH_2$ and jet A cost are shown in Figure 8-3 and 8-4 In Figure 8-3 the comparison is shown for a coal derived jet fuel, (meeting current specification) to $LH_2$ as a ratio of the flight fuel cost for the two fuels to the ratio of the cost of the two fuels as delivered to the aircraft. As shown, with a subsonic aircraft, considering only the flight fuel cost, $LH_2$ would have to cost 1.1 times the same as coal derived jet A cost on a BTU basis for $LH_2$ to breakeven. For supersonic aircraft the ratio is about 1.38, compared to a cost ratio of 2.07 from this study.

It is realized that this comparison includes only the fuel cost, while the other direct operating cost items (crew, maintenance, insurance, etc.) should also be considered, as well as the return on investment for the aircraft. If the cost of the two aircraft are about the same, as was shown in Table 8-5, then the fuel cost is a fair measure of the total cost comparison.

For supersonic aircraft, the data in Table 8-12 implies that a Jet A type aircraft will cost 1.35 times more than a $LH_2$ aircraft. It is beyond the scope of this study to make a detailed comparison which includes all cost components, but a rough estimate is shown in Figure 8-3 to illustrate the direction the curve moves. If one assumes 400 flights per year, that the cost given on Table 8-12 are in 1973 dollars and these can be inflated to $1980 at a 7 percent per year inflation rate, and that the airlines require a 20 percent capital recovery factor, then it is possible to calculate the ratio of the cost for ROI and fuel cost, as shown by the dotted line. This would imply that a $LH_2$/jet A - coal cost ratio of about 1.7 would be needed to breakeven. A more detailed study would be needed to firm up this number, and to include crew and maintenance cost.

Figure 8-2

Effect of Design Range on Figure of Merit of a 250 Passenger, Mach 27 SST



Source: Ref. (8-35)

Figure 8-3

Comparison of Cost for Subsonic and Supersonic Aircraft for $LH_2$ and Coal Derived Jet A

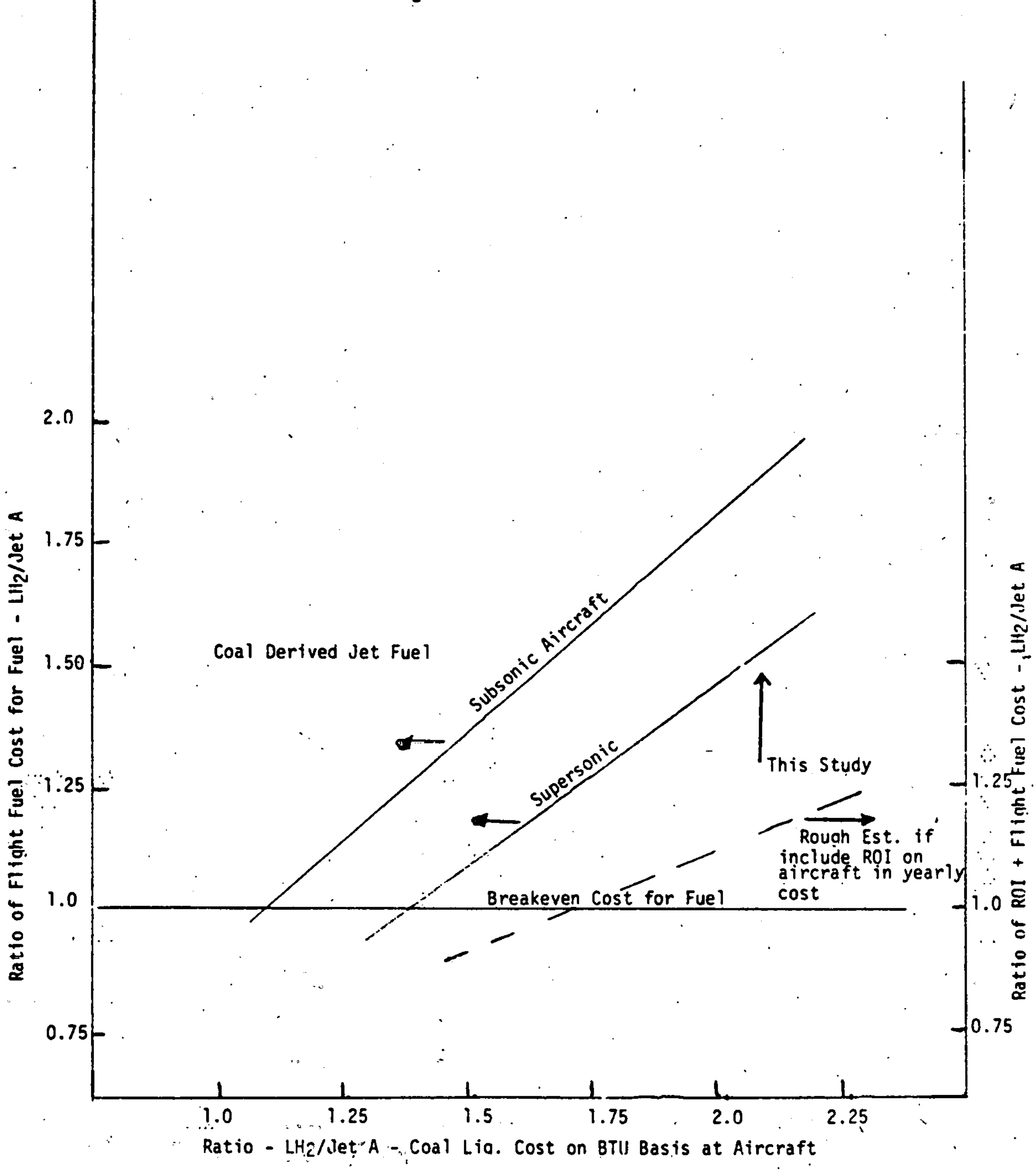
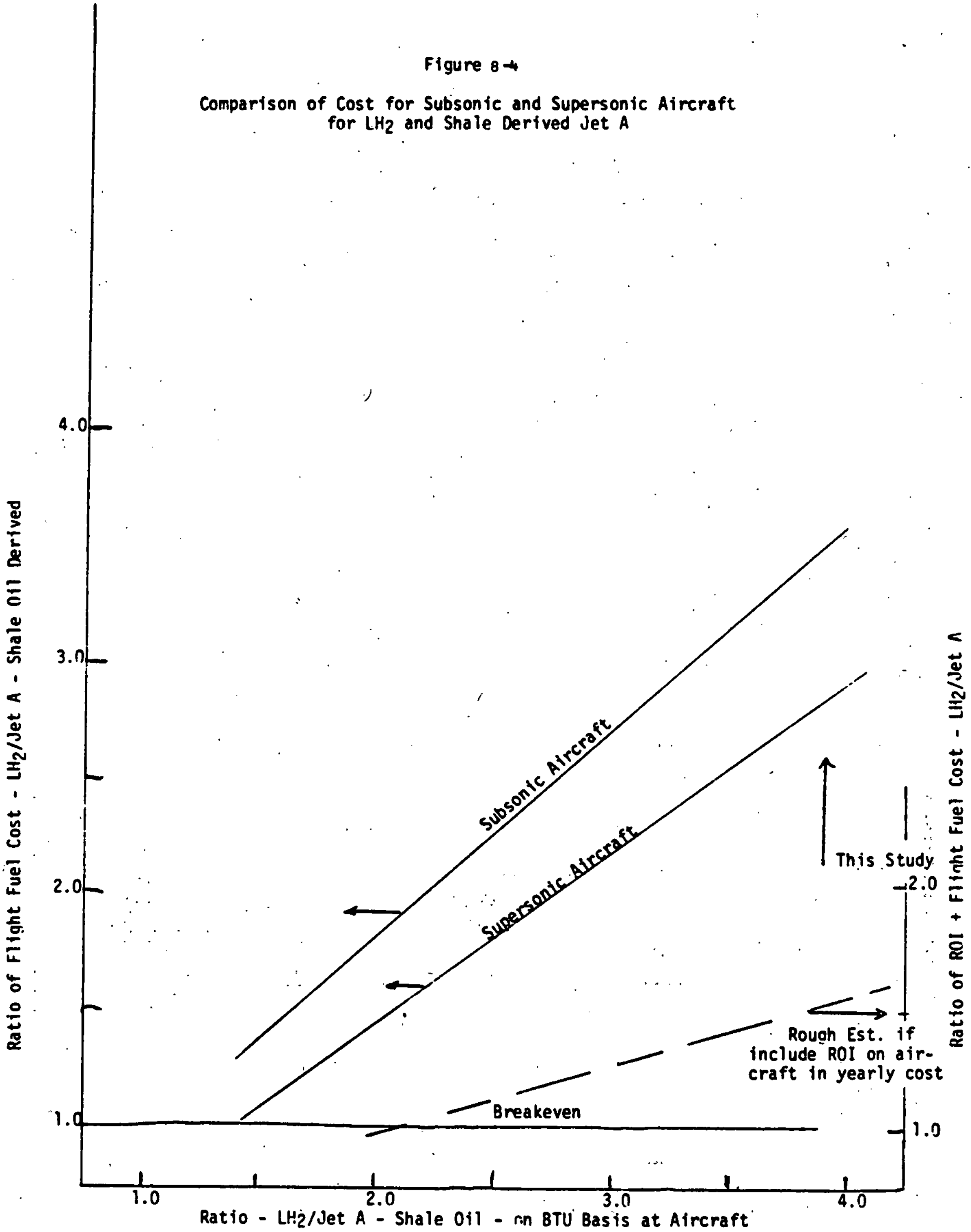


Figure 8-4

Comparison of Cost for Subsonic and Supersonic Aircraft for $LH_2$ and Shale Derived Jet A



For a shale oil based jet A, a more likely case, the cost of $LH_2$ would have to show even a greater percentage reduction to breakeven with jet A from shale oil, considering only fuel cost, as shown in Figure 5-4 for both subsonic and supersonic case. If the ratio is based on the ROI cost and fuel cost, using the same assumption as for the coal liquids, the the $LH_2$ cost would have to be reduced 45 percent over that used in this study, in a ratio of about 2/1, compared to shale oil.

### 8.3.3 Resource Requirements

A comparison of the basic resource requirement for the five direct fuels is shown in Table 8-17 for subsonic aircraft. The comparison is made on the basis of the amount of fuel required for a given flight, based on data from Table 8-5. If all five fuels are considered, then shale oil derived fuels represent the most efficient use of natural resources, followed by direct coal liquefaction and $LCH_4$ with $LH_2$ requiring about double the amount of resources as a jet A fuel from shale. If the comparison is made only on the coal based fuels, then direct coal and $LCH_4$ are about a standoff as the most efficient, followed by indirect coal liquefaction derived fuels, and $LH_2$ from coal.

For supersonic aircraft, the comparison is limited to $LH_2$ and synthetic jet, based on data from Table 8-12. As shown in Table 8-18 shale oil based jet A is still the most efficient use of natural resources. With all coal based fuels, coal liquids are the most attractive fuel.

The study by Rand includes data of the direct energy consumption for building the aircraft.(5-7) The aircraft acquisition energy includes all of the energy consumed by the aircraft manufacturing facility.

Illustrative Life-Cycle Direct Energy Consumption
For The Design-Point Alternatives
(Quads)

| Aircraft | Acquisition | 20-Years' Fuel | Total |
|---|---|---|---|
| VLA-JP | 0.04 | 1.15 | 1.19 |
| VLA-$LCH_4$ | 0.04 | 1.22 | 1.26 |
| VLA-$LH_2$ | 0.03 | 1.01 | 1.04 |

NOTE: Based on the procurement of 112 UE aircraft and on an average UTE rate of 720 flying hours per year.

Source: Ref. (8-7)

As shown above, the acquisition energy is only about 3-4% of the total. The 20 year fuel is the energy consumed by the aircraft fleet and does not include the energy loss necessary to manufacture the fuel. If the aircraft were used 2650 hours per year, the acquisition energy would represent less than 1% of the total energy consumed. The main point is that the acquisition energy can be ignored in an energy resource comparison.

## Table 8-17

## Resource Requirements For Subsonic Aircraft With Various Alternate Fuels

| | $LH_2$ | $LCH_4$ | Jet A | | |
|---|---|---|---|---|---|
| | | | Shale | Direct Coal | Indirect Coal |
| Block Fuel⁽¹⁾ | | | | | |
| Lbs | 47,666 | 129,000 | --------- | 159,900 | ----------- |
| BTU x $10^9$ | 2.46 | 2.77 | | 2.93 | |
| <u>Fuel Resource Requirement</u> | | | | | |
| Mine BTU/Gross Fuel BTU | 3.37 | 1.85 | 1.59 | 1.82 | 2.30 |
| Gross/Net BTU | 1.18 | 1.125 | 1.068 | ----- 1.055 | ------- |
| Resource Req'd Mine/Net BTU/Flight | 9.78 | 5.77 | 4.98 | 5.63 | 7.11 |
| Ratio - All Fuels | 1.96 | 1.16 | 1.0 | 1.13 | 1.43 |
| - | 1.74 | 1.02 | - | 1.0 | 1.26 |

(1) Based on data from Ref. (8-5)

Table 8-15

Resource Requirement For Supersonic Aircraft With Various Alternate Fuels

| | $LH_2$ | Jet A | | |
|---|---|---|---|---|
| | | Shale Oil | Direct Coal | Indirect Coal |
| Block Fuel(1) | | | | |
| Lbs | 85,390 | 330,590 | | |
| BTU x $10^9$ | 4.40 | 6.08 | | |
| Fuel Resource Requirements | | | | |
| Mine BTU/Gross Fuel BTU | 3.37 | 1.59 | 1.82 | 2.30 |
| Gross/Net BTU | 1.18 | 1.068 | 1.055 | |
| Resource Req'd | | | | |
| Mine/Net BTU/Flight | 17.50 | 10.32 | 11.67 | 14.75 |
| Ratio - All Fuels | 1.70 | 1 | 1.13 | 1.43 |
| - Coal Based | 1.5 | - | 1 | 1.26 |

(1) Based on data from Ref. (8-6) and Table 8-12.

## 8.4 Synthetic Jet Fuels

The type of jet fuels in use currently and the specifications summarized are in the Appendix Volume IIIA. New types of fuels can have an impact on the combustion system and the fuel systems. In the following sections the potential impact of fuel properties on these two major systems are described and how potential solutions to the problems are outlined.

### 8.4.1 Combustion System

The most serious fuel impacts on the combustion system are combustion efficiency, combustion stability, ignition, size, weight, cost durability, maintainability, reliability and exhaust emissions. Some of these areas are covered in the following sections along with a comparison between coal liquids and shale oil derived jet fuels.

#### 8.4.1.1 Combustion Stability and Ignition

The principal fuel properties that affect the ignition and relight limits and combustion stability are volatility and viscosity. These two fuel properties affect the atomization and vaporization characteristics of the fuel as it is sprayed into the combustion chamber. Both of these properties are controlled by the boiling range of the fuel, and a review of jet fuels produced from coal liquids and shale oil shows that there are no major differences between these two types of synthetic fuels on viscosity.

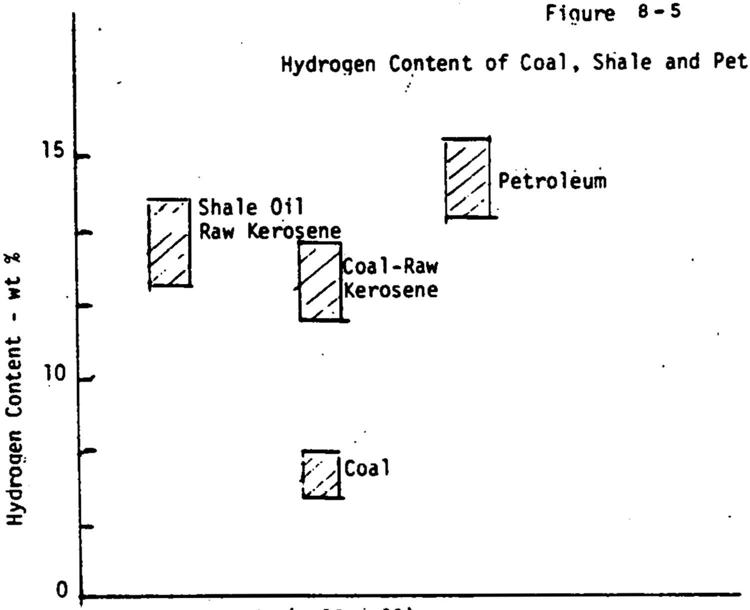
#### 8.4.1.2 Durability, Reliability, and Maintainability

Durability, reliability and maintainability can be seriously affected by fuel hydrogen content. As shown in Figure 8-5, coal and shale based hydrocarbons contain less hydrogen then petroleum. Shale oils before upgrading tend to be in the 10.5 - 14 percent hydrogen(8-11). Kerosene from direct coal liquefaction process, before upgrading typically falls in the 9.5 - 12 percent range. The relationship between aromatics content and hydrogen content of the fuel is shown in Figure 8-6. A limited check shows that shale oil derived jet fuels fall within the band, while coal derived jet fuels fall slightly below the band.

A decrease in hydrogen content increases flame radiation, hence combustor liner heating, as shown in Figure 8-7. Several potential design approaches can improve component durability and reduce maintenance requirements - such as lean combustion techniques, advanced materials and coatings, advanced liner coating techniques and improved structure. Lean combustor can reduce the effect of fuel hydrogen content on flame luminosity and reduce liner temperature, as shown in Figure 8-8. It is also interesting to note that the maximum liner temperature was over 200°C lower than conventional combustors. Thus, while coal and shale liquids are lower in hydrogen, changes in engine design may reduce the need for upgrading to today's hydrogen level, assuming the upgrading is not required for some other property - such as thermal stability. The economics of upgrading compared to new engine are discussed in Section 8.5.

Figure 8-5

Hydrogen Content of Coal, Shale and Petroleum Jet Fuels



Source: Ref. (8-10, 8-11)

Figure 8-6

Relationship Between Hydrogen Content and Aromatics

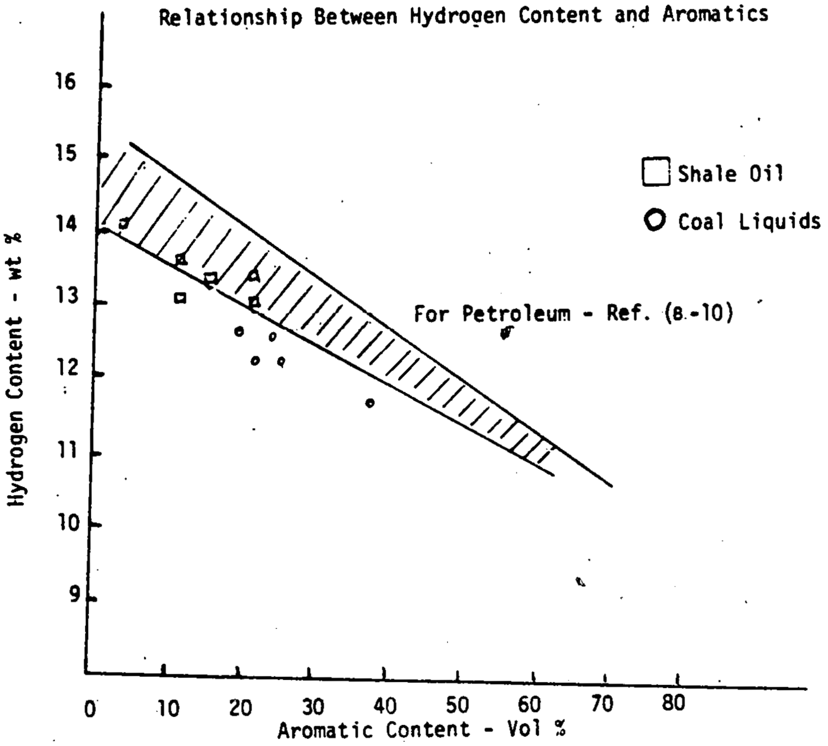
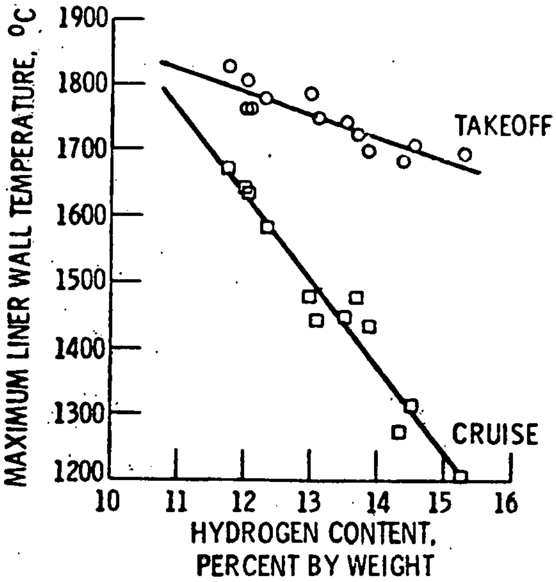


Figure 8-7

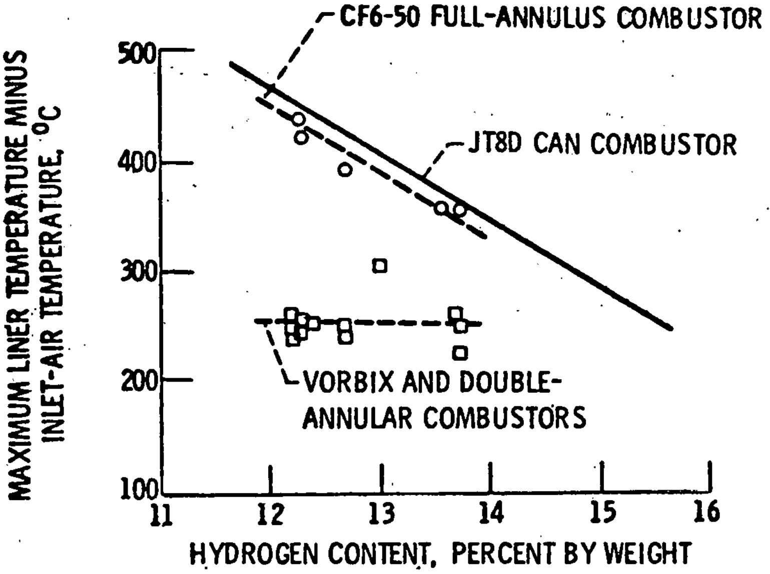
Effect Of Fuel Hydrogen Content on Maximum Combustor Liner Wall Temperature



Source: Ref. (8-6)

Figure 8-8

Effect of Fuel Hydrogen Content on Maximum Combustor Liner Temperature



Source: Ref. (8-12)

### 8.4.1.3 Exhaust Emissions

The principal fuel properties that can affect engine exhaust emission are volatility, hydrogen content, and fuel bound nitrogen content. Fuel hydrogen content can affect all four pollutant emissions with the current technology jet engines. Figure 8-9 illustrates the effect of fuel hydrogen content on carbon formation, expressed in terms of SAE Smoke Number, the standard for the aircraft industry.(8-12) Figure 8-10 shows the carbon monoxide and unburned hydrocarbon emission for this same type of combustor at idle conditions as a function of fuel hydrogen content. The effect of fuel hydrogen on $NO_x$ emission is illustrated in the Figure 8-11. This increase in $NO_x$ emission was attributed to a possible increase in combustion flame temperature that could have occurred as the fuel hydrogen content was decreased. The affect of fuel-burned nitrogen on $NO_x$ emission is shown in Figure 8-12. $NO_x$ emission increased substantially at all operating conditions as fuel-bound nitrogen content increased. As shown in Figure 8-13, shale oil kerosene contains considerably more organic nitrogen than coal derived fuels or petroleum. Shale oil kerosenes range from .8 - 1.5 wt percent organic nitrogen, while coal liquids are in the .1 - .4 wt percent range, while most petroleum kerosene are normally less than 0.1 percent nitrogen.(8-11)

Several potential design changes can be used to control exhaust emission. An example of the changes in exhaust emission with the Vorbix and double-annular combustor concepts, being developed as part of the NASA Clean Combustor Program, is shown in Figure 8-14. Thus, it should be possible to design new engines that could operate with lower hydrogen content fuels and still meet projected emission standards.

### 8.4.2 Engine Fuel Systems

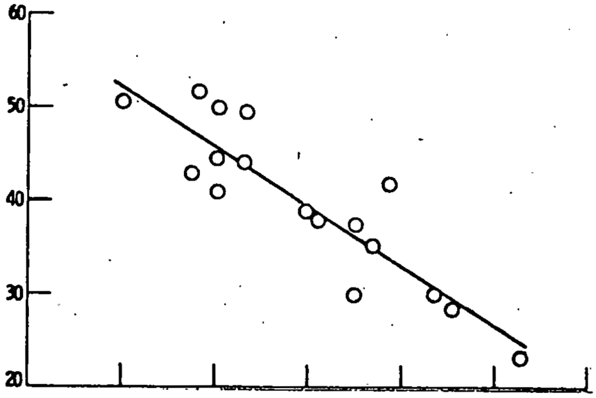
Key factors affecting the fuel system are aromatics, olefins, fuel bound nitrogen, as well as freeze point and gum content. Potential problems include fuel breakdown to form deposits and/or gum, plugging fuel system components, reduction of oil cooling capacity, and viscosity increases or freezing of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

### 5.4.2.1 Thermal Stability and Deposition

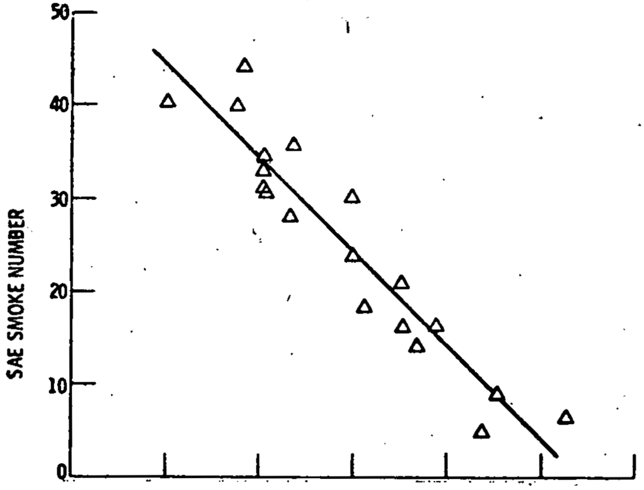
Increasing fuel-bound nitrogen content can result in a less thermally stable fuel.(8-11,8-12,8-14,8-16) Breakdown temperatures of a number of shale and coal derived fuel samples are shown in Figure 8-15. The fuels hydrotreated severely to 100-200 ppm (.01 - .02 wt percent) had breakpoints in the 470-525°F range. Thus to have breakpoints of 500°F or more, it appears the coal and shale fuels will have to be hydrogenated to nitrogen levels below about 100 ppm.(8-12)

Figure 8-9

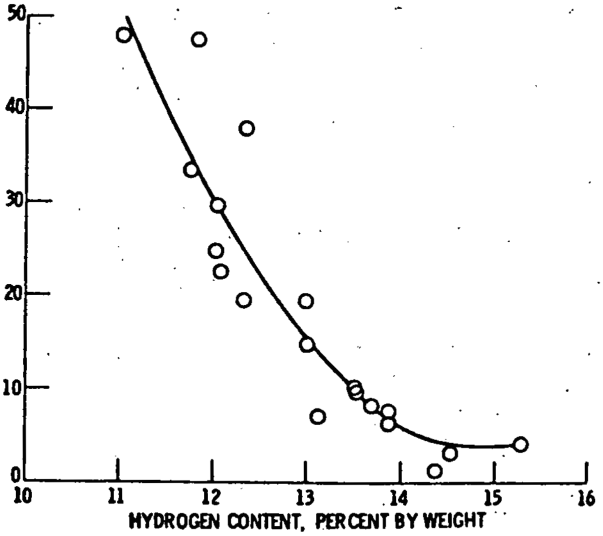
Effect of Fuel Hydrogen Content on Smoke Number



(a) TAKEOFF CONDITIONS.



(b) CRUISE CONDITIONS.

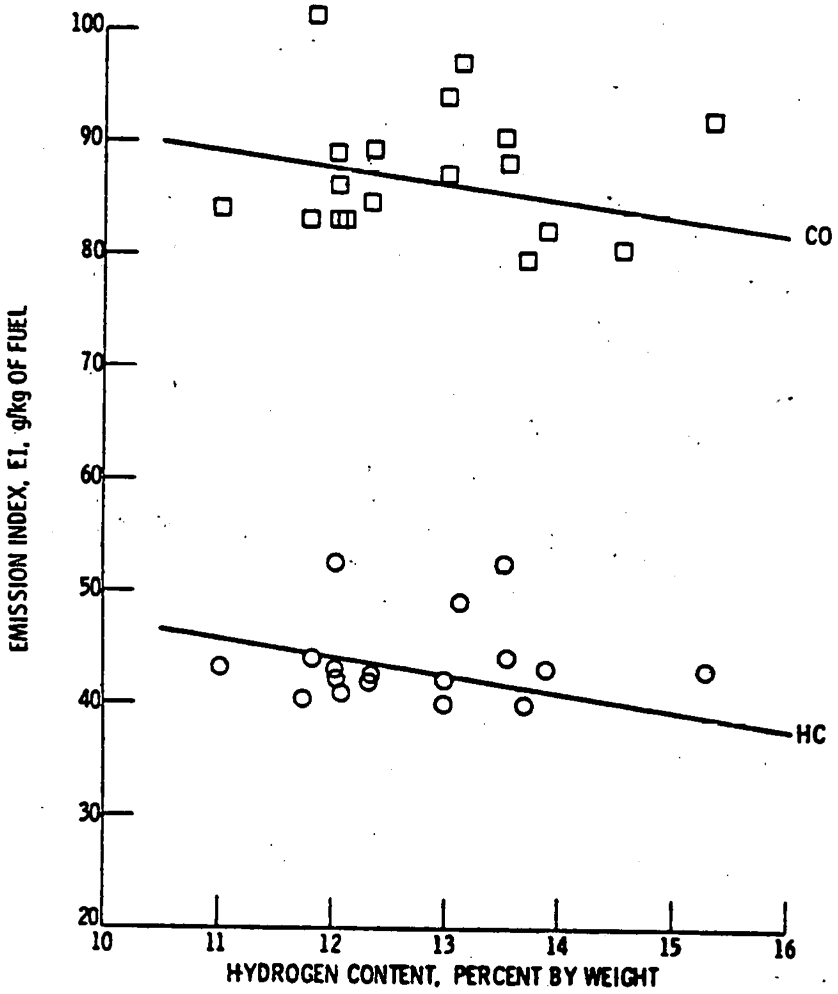


(c) IDLE CONDITIONS.

Source: Ref. (8-12)

Figure 8-10

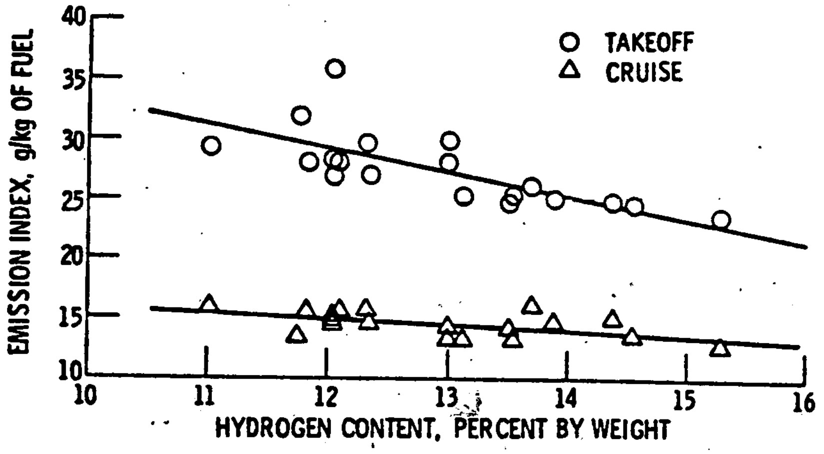
Effect of Fuel Hydrogen Content on Emissions of Carbon Monoxide and Unburned Hydrocarbons at Idle Condition



Source: Ref. (8-12)

Figure 8-11

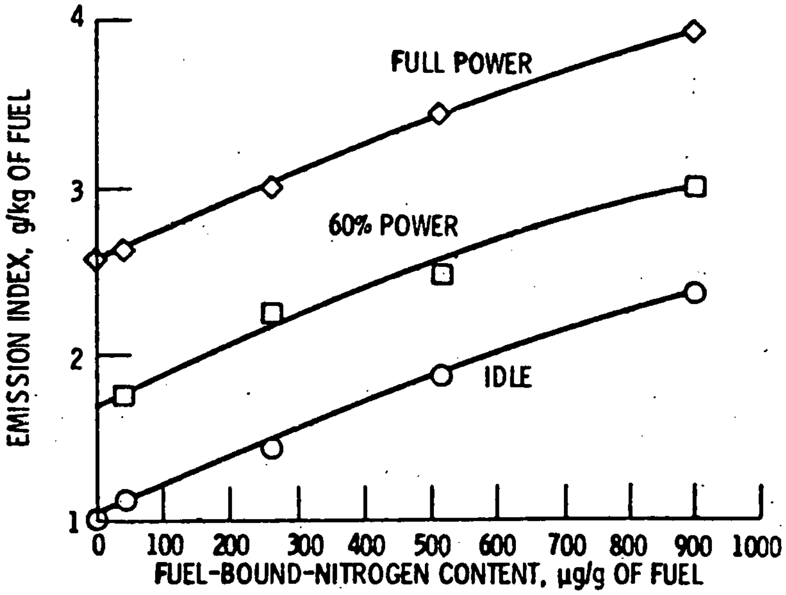
Effect of Fuel Hydrogen Content on Emissions of Nitrogen Oxides at Takeoff and Cruise Conditions



Source: Ref. (8-12)

Figure 5-12

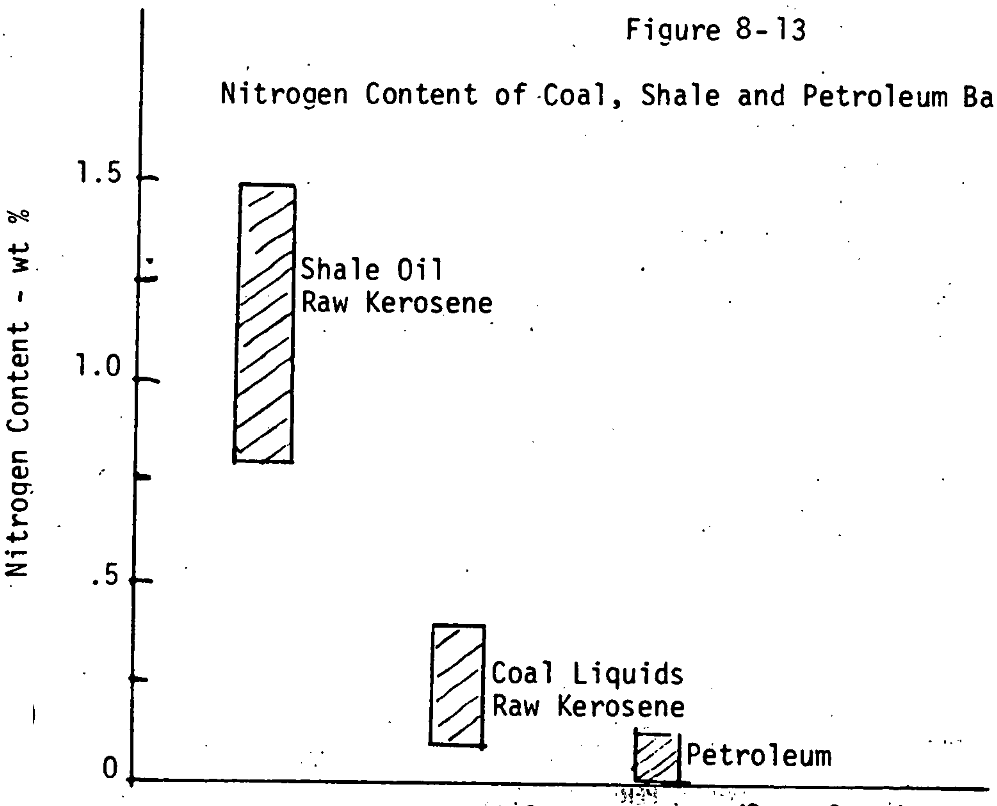
Effect of Fuel Bound Nitrogen Content on Total Emissions of $NO_x$



Source: Ref. (5-12)

Figure 8-13

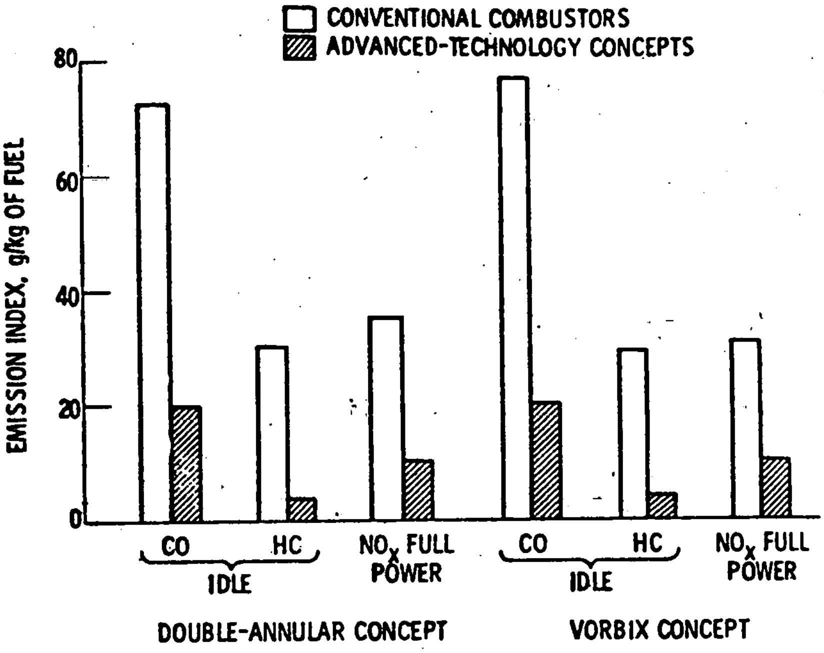
Nitrogen Content of Coal, Shale and Petroleum Based Jet Fuels



Source: Ref. (8-10,8-11)

Figure 8-14

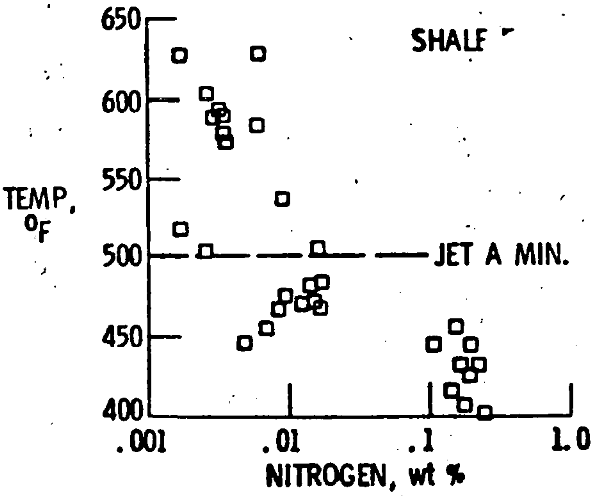
Emission Reduction Capability of Selected Advanced-Technology Combustor Concepts



Source: Ref. (8-12)

Figure 8-15

Variation of Breakpoint Temperature with Nitrogen Level



Source: Ref. (8-11,8-14)

Coal and shale derived fuels will behave different since shale oil derived fuels are much higher in nitrogen. For example, as shown in Figure 8-16, if shale oil based jet fuels are reduced to 100 ppm nitrogen, the aromatics will generally be less than 10 - 15 percent, while with coal based fuels, the aromatics may be as high as 50 - 60 percent. A general trend to higher breakpoint temperatures was observed as the weight percent of hydrogen was increased, as shown in Figure 5-17. A 260°C breakpoint generally requiring at least 13 percent $H_2$.(8-10)

Hydrotreating is not the only possible approach to solving the thermal stability problem. It may be that modification can be made to the fuel system so that the fuel does not reach as high a temperature level. This would permit the use of fuels of lower thermal stability.

### 8.4.2.2 Fuel Pumpability and Flowability

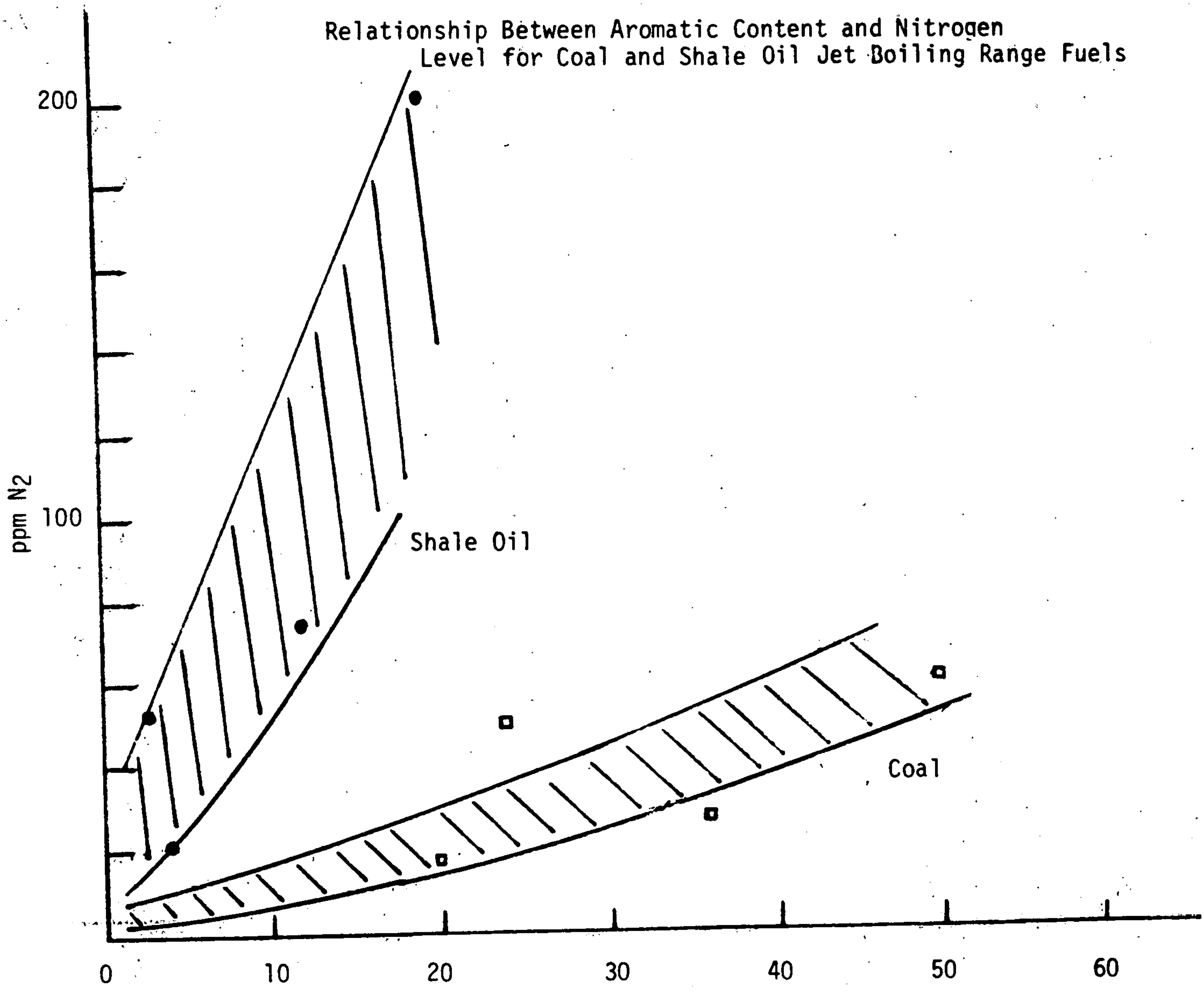
The fuel property that can affect the flowability of the fuel at low temperature is the freeze point. As shown in Figure 8-18, the freezing point increases as the final boiling point is increased.

The fuel point is controlled by the temperature at which wax crystallites first form as the fuel temperature is reduced and is controlled by the concentration of the highest carbon number normal paraffins present in the fuel.(8-36) Because shale liquids contain higher levels of n-paraffins than generally does petroleum, they have higher (poorer) freeze points. By contrast, coal liquids which are low in total paraffin content tend to have lower (better) freeze points. In fuel flow tests, such as a pour point test, fuel "flowability" may cease when as little as 2-3 weight percent solids in the fuel are formed.(8-37) Although current jet fuel specifications are written around a freeze point value, which is an incorrect property of fuel composition, the critical property is low temperature flowability which is measured by a pour point test. It is possible to improve the low temperature flow properties of distillate fuels (i.e. to reduce the pour point of the fuel) by the use of wax crystal modifier types of additives which change the morphology of the wax crystallites from their interlocking plates to a more favorable geometry.(8-37) Similarly, it is possible to improve the low temperature flow properties of a fuel by methods which reduce or remove the highest carbon number n-paraffins such as selective hydrocracking, isomerization, molecular sieving or short solvent extraction. Thus, if the final boiling point is increased to increased fuel availability, then the freeze point would be increased.

A preliminary study on the effect of high-freezing point fuels on the design of commercial aircraft fuel systems has been carried out by Boeing under NASA Contract.(8-17) The study evaluated two different fuels: (1) a fuel with 0°F freeze point that would require 6200 Btu/min/tank heat requirements for the extreme minimum in flight ambient temperature conditions; and (2) a fuel with a -20°F freezing point that would require 3500 Btu/min/tank heat requirements. The heating requirements could be reduced by insulating the fuel tanks, but insulation alone was insufficient to maintain fuel temperatures above the freezing point in all cases.(5-17)

Figure 8-16

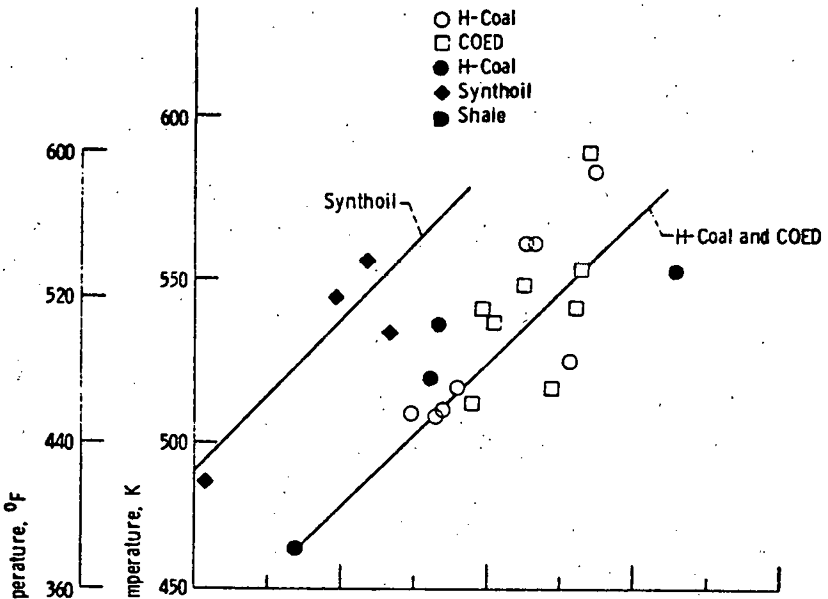
Relationship Between Aromatic Content and Nitrogen Level for Coal and Shale Oil Jet Boiling Range Fuels



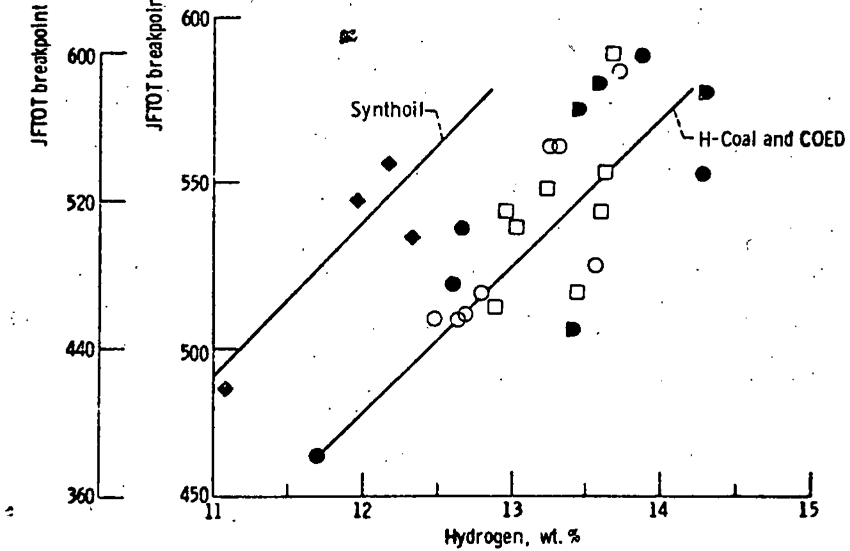
Source: Based on data from Ref. (8-15)

## Figure 8 - 17

## Variation of Breakpoint Temperature with Hydrogen Content of Low-Nitrogen (<67 ppm) Fuels



(a) Coal fuels.

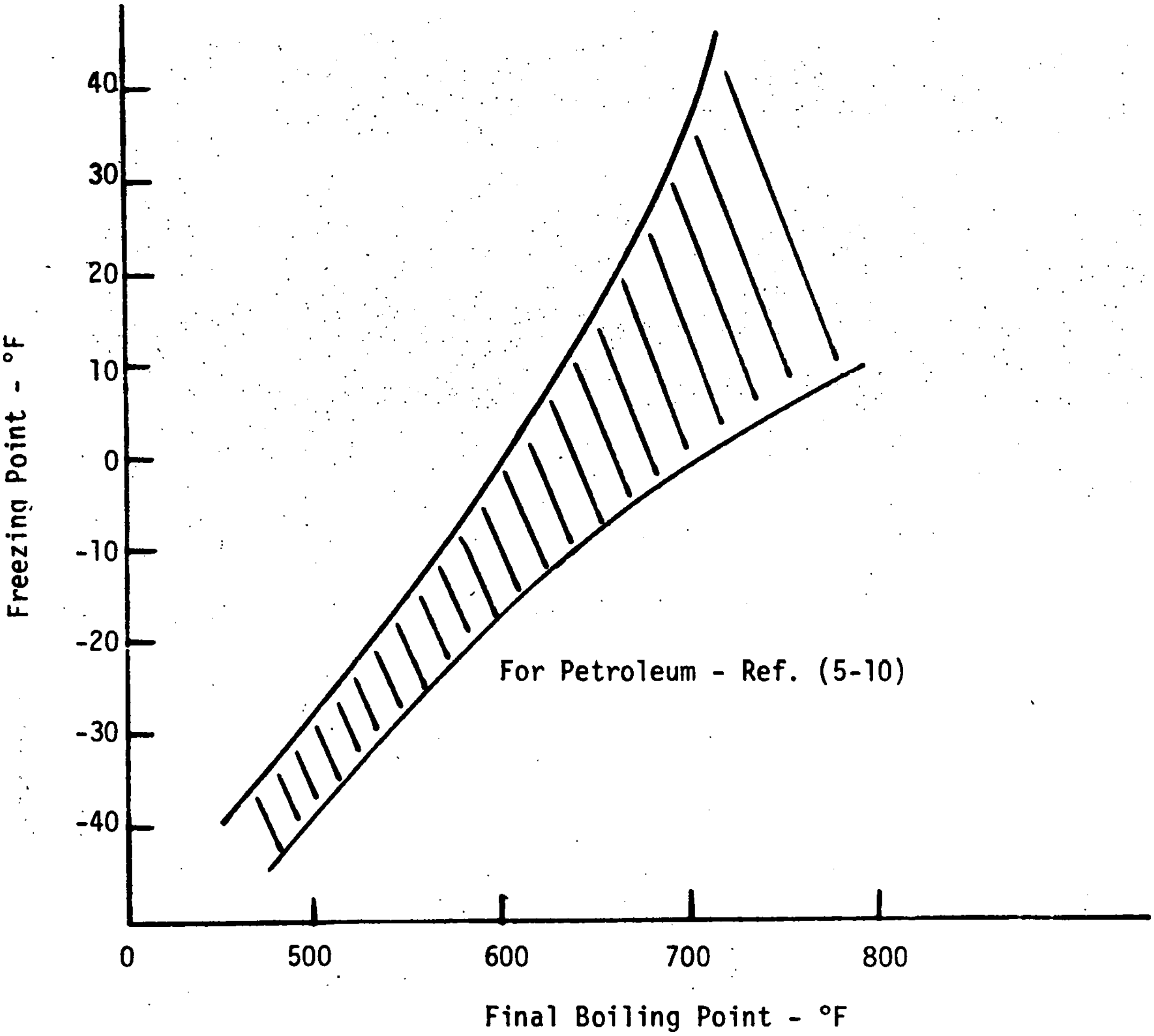


(b) Coal and shale fuels.

Source: Ref. (8-16)

Figure 8-18

Relationship Between Freeze Point and Final Boiling Point for Jet Fuels



Several modifications to existing aircraft systems were investigated, from minor changes using existing heat rejected by the aircraft system to major changes which involve more extensive changes for the 0°F freezing point. The economic penalty to make the necessary changes were very small, generally less than 1¢/gallon. If ground handling modifications would be required, these can also be made for a minimal cost, like 0.01¢/gal. of fuel handled. Thus, use of higher freeze point fuels should be seriously considered.

### 8.4.2.3 Material Compatibility

One possible area of concern in the aircraft fuel system is the possible impact that increasing aromatics may have on the elasticity of elastomer compounds and sealants. One possible effect is shown in Figure 8-19.

### 8.4.3 Storage Stability

Another factor to be considered is the relative storage stability of the synthetic fuels and the influence of fuel upgrading on storage life. With shale oil based jet fuels, it appears with a fuel nitrogen level of over 100 ppm, sludge will form under normal storage conditions.(8-11,8-13) With deoxygenated fuels stored in the dark, the amount of sludge may be less. The order of magnitude of the problem has not been defined, as to the feasibility and cost to filter out the sludge. Data are not known to exist on how coal liquids would behave on storage stability. This is an area that requires additional study.

### 8.4.4 Summary - Synthetic Jet Fuels from Coal and Shale

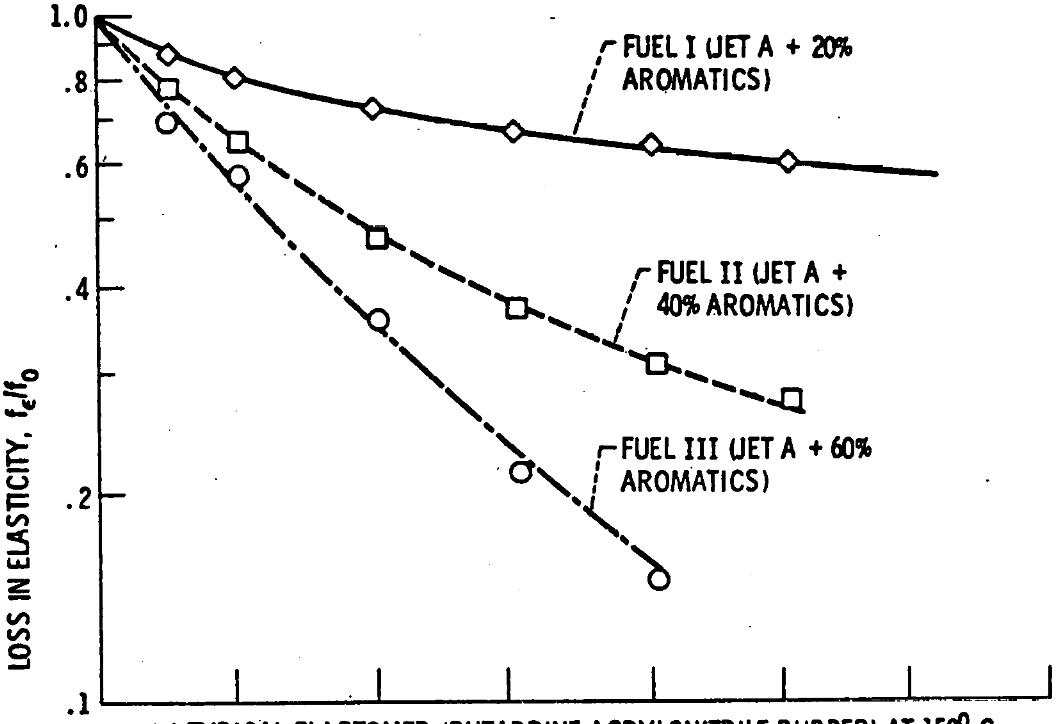
It should be possible to produce acceptable jet fuels from either coal or shale oil resources. Fairly large samples of jet aircraft fuels have been produced from shale oil.(8-26,8-27) It appears that the production of aircraft jet fuels from shale oil-derived crude is technically feasible and should be more straightforward than would be the comparable production from coal-derived oils.(8-15) 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 high pressure. Increasing processsing 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.

In comparing coal derived jet fuels to shale oil derived fuels, at the same aromatic level, the following has been observed.(8-15)

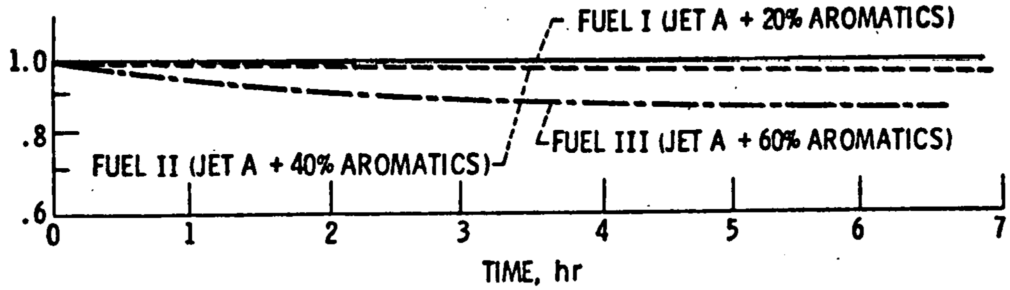
Density - Coal derived jet fuels will have higher density than shale or petroleum based fuel.

Figure 8-19

Effect of Various Fuels on Material Elasticity



(a) TYPICAL ELASTOMER (BUTADRINE ACRYLONITRILE RUBBER) AT 150° C.



(b) TYPICAL SEALANT (FLUOROSILICONE RUBBER) AT 150° C.

Source: Ref. (8 -12)

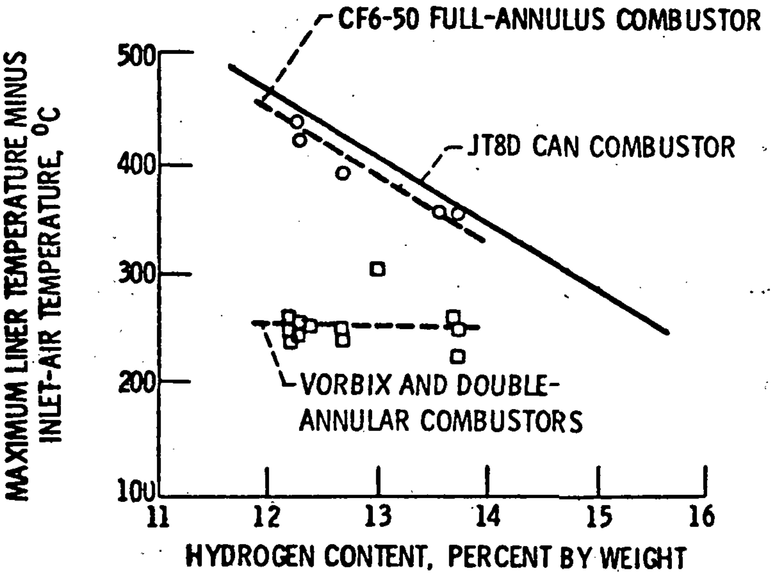
Luminometer Number - Coal based jet fuels will have poorer combustion properties than shale oil or petroleum based fuel, due to the formation of naphthenes rather than paraffins when the coal liquid is hydrogenated.

Freeze Point - Coal derived fuel will have a lower freeze point than a shale or petroleum based fuel at a given end point.

Heat of Combustion - Coal based fuel will have a higher volumetric heat of combustion and a lower weight heat of combustion than a shale oil-derived fuel. However, this difference is relatively small.

## 8.5 Economic Comparison Between Upgrading Fuels to Meet Current Hydrogen Levels and Modifying the Engine

With coal derived synthetic fuels, the hydrogen content can run around 7-10 percent before upgrading. Current petroleum jet fuels run around 14 percent hydrogen. The cost to add hydrogen to a coal derived jet fuel can be appreciable as was shown in the Appendix Volume IIIB, Section 6. An alternate to adding hydrogen would be to develop an engine that could operate satisfactory with a 10-12 percent hydrogen content fuel. The Vorbix and Double-Annular combustors, being developed as part of the NASA Experimental Clean Combustor Program, have shown that the maximum combustor liner temperatures are insensitive to fuel hydrogen content, as shown below.



Source: Ref. (8-12)

This technology was developed by Pratt and Whitney (Vorbix) and General Electric (Double Annular) to meet future $NO_x$ standards. While these combustion systems themselves may not be applicable to future fuels they do represent technology which might be suitable and the application of cost information from these devices to the current problem is valid. Information has been reported on the estimated incremental cost of producing this new engine, the increased maintenance cost and any fuel penalties, that can be used to make the economic comparison between fuel upgrading and engine modification.(8-3,8-19,8-20) The following sections will summarize the economic basis used for the new engine and the last two sections will show the breakeven point for switching engines or upgrading the fuel.

## 8.5.1 Cost of New Engine

The incremental cost of a new engine can be divided into four major components: non-recurring, manufacturing, maintenance, and operating.(8-19) The non-recurring cost covers design, development, certification and initial production. These funds represent the investment by the engine builder to develop and demonstrate new technology for a specific engine family that must be recovered in the engine selling price. Not included are the R&D cost of initial design that is generally funded by the Government. The manufacturing cost refers to the incremental cost in the engine selling price as a consequence of increased complexity or more expensive materials for the new engine. For the Vorbix engine, Pratt and Whitney has estimated the price increment for the JT9D and JT10D engine at around $300,000 (1978 dollars).(8-3) In terms of 1980 dollars this is around $350,000. This cost includes the amortization of the non-recurring development cost over their anticipated sales and a return on investment plus the incremental manufacturing cost for the engine.

The increased complexity of the Vorbix type engine is expected to lead to increases in maintenance cost. This is particularly true for combustors since the burner can greatly influence turbine life. A range of maintenance cost has been presented in a study for the EPA, based on data submitted by Pratt and Whitney.(8-3) One case assumes that the burner life is equal to that achieved today, while the other case assumes the burner life is reduced by 50 percent. The increased maintenance cost, in terms of 1980 dollars is $33,000 per year per engine for the first case, and $139,000 per year per engine for the second case. Changes to operating cost are related to increases in fuel usage.

The engine producers claim that there will be no change in specific fuel consumption, but the Vorbix type engine will weigh more. This added weight will cause the aircraft to burn more fuel to carry a given payload on a given flight. This impact is fairly small, $4-7,000 per year per engine, after adjusting to $1980 and for higher fuel cost.

The only other factor to consider is the cost associated with a possible premature introduction of a new engine into service. If the engines are not thoroughly tested before being put into service, then there will be additional shop cost to remove the engines and correct the problems. This should represent a "worst case" estimate and would amount to $240,000 per engine per shop visit.(8-3)

The cost of introducing a new engine would then be as follows for a JT9D or JT10D type engine for a 4 engine wide body plane:

| | |
|---|---|
| Incremental Cost of New Engine | $350,000 (1980 dollars) |
| Increased Maintenance | |
| - Same burner life as today | $33,000/yr/engine |
| - Burner life reduced by 50 percent | $139,000/yr/engine |
| Increased Fuel Penalty | $4-7000/yr/engine |
| Service Test Penalty | $240,000/engine per shop visit |

### 8.5.2 Fuel Cost Savings

To offset the added cost of installing an engine that would have greater fuel flexibility there needs to be a reduction in fuel cost. In the case of coal derived fuels, it is assumed this will be accomplished by not having to add hydrogen to the fuel. To quantify this, it is necessary to know the amount of fuel used per engine per hour, the number of hours each engine is used per year, the heating value of the fuel and the cost to be saved by using a lower hydrogen content coal derived jet fuel. The following values were used for this study, with the source of the information shown on the right.

| Fuel Related Factor | Source of Data |
|---|---|
| 1. Volume of Fuel Used Per Engine - 870 gal/hour | Energy statistics(8-21) reported the fuel cost/hour for five airlines, flying B747's and the cost per gal. This allowed the average fuel consumption to be calculated. |
| 2. Number of Hours Per Year - 2650 | EPA study that gives the average hours per year for B747 aircraft for 1976.(8-3) |
| 3. Heating Value of Coal Derived Jet Fuel - 130,000 BTU/gal | This study. |
| 4. Cost of Adding Hydrogen to Coal Liquids. Depends on Coal Liquids, but used the following: | This study. |

| % $H_2$ | Δ $/MBTU |
|---|---|
| 4 | 1.85 |
| 2 | 0.94 |
| 1 | 0.47 |

### 8.5.3 Economic Comparison

The cost savings from using a lower hydrogen content fuel, compared to the added cost for a more versatile engine and increased maintenance cost are shown in Figure 8-20. If the burner life is the same as the current engines and the added expenses includes the incremental cost of the new engine with a 20 percent capital recovery factor, the increased maintenance cost and the small incremental fuel cost, then the airline should see an incentive to use the new engine if the hydrogen content can be 13.2 percent compared to the current 14 percent. If a 12 percent hydrogen fuel can be used, the incentive would be about $170,000 per year per engine to use an engine that can handle a fuel with a lower hydrogen content. If the coal derived jet fuel could be 10 percent hydrogen in place of 14 percent, the incentive would be $440,000 per year per engine.

If the burner life is reduced by 50 percent, the incentive drops to $60,000 per year per engine for a 12 percent hydrogen fuel, over and above about a 10 percent return on the incremental cost of the new engine. If the service test penalty is also included, the breakeven point, including a 10 percent return is 12 percent hydrogen.

The absolute level of the numbers are not as important as the point that clearly there is an economic incentive to develop an engine that can accept a poorer quality fuel. Since the Vorbix and Double Annular combustor are being developed for emission control, they may be in service before any coal derived jet fuels are used, and it may be possible to develop even a better engine or improve on the burner life.

### 8.5.4 Breakeven Cost for Petroleum Type Fuel

Since it is possible to also have a petroleum based fuel with a lower hydrogen content, it is interesting to calculate the necessary fuel cost reduction necessary to breakeven with the airline's added cost for the new engine and added maintenance cost. Based on the engine cost data shown in 8.5.1, the added expense is $110,000/year(1) per engine of the burner life is the same as current engines and $216,000/year per engine if the burner life is reduced by 50 percent. This includes a 20 percent capital recovery factor on the incremental engine investment. The fuel would have to cost 5¢/gal. less for the first case and 9¢/gal. less for the latter case to break even.

## 8.6 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.

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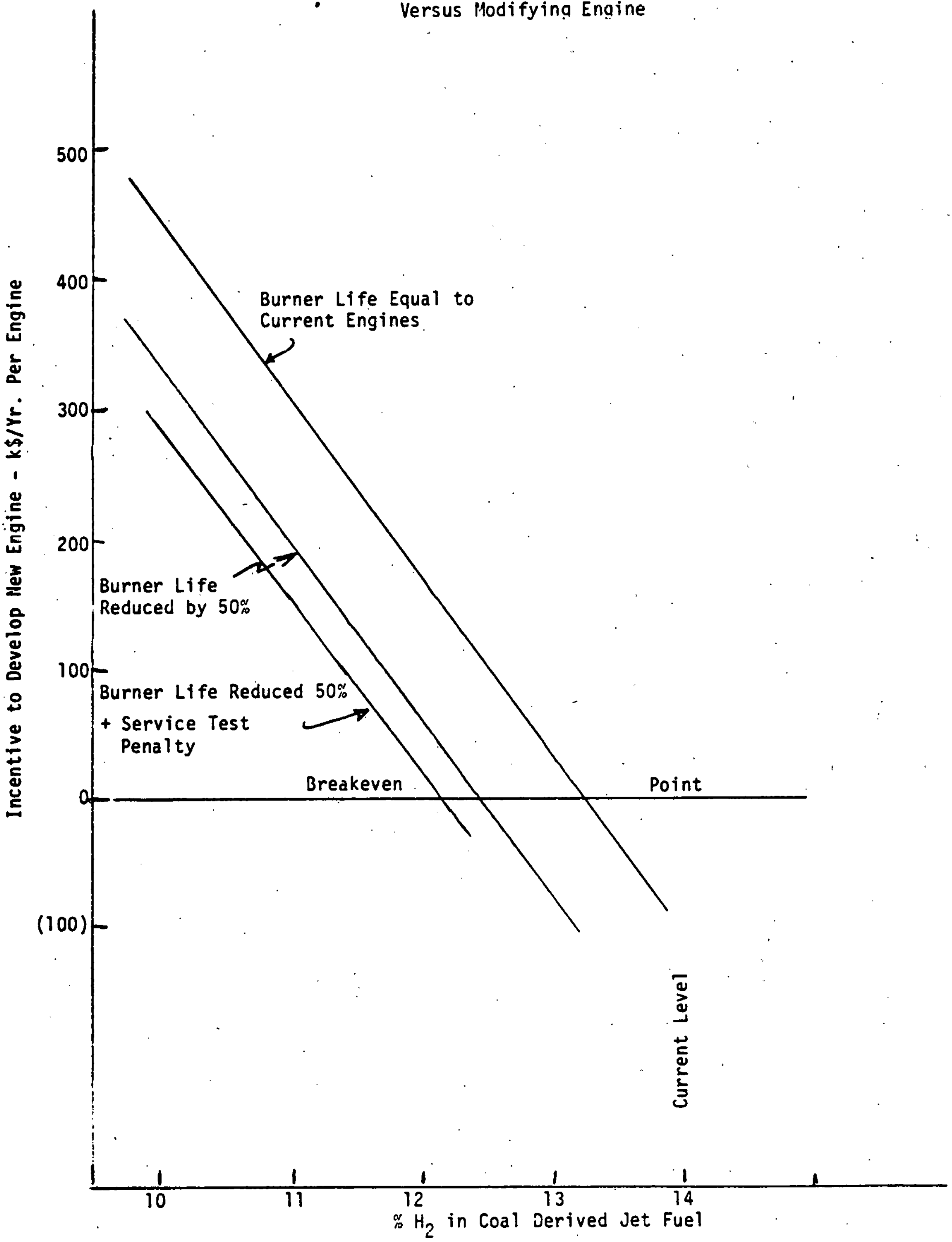
(1) Calculated as follows: $350,000 for new engine x .2 CRF + $33,000 maintenance + $7000 fuel = $110,000

Figure 8-20

Economic Comparison of Upgrading Coal Derived Jet Fuel Versus Modifying Engine



A broadcut fuel, does not increase petroleum supply it increases jet fuel supply <u>at the expense</u> of something else - such as diesel fuel, chemical feedstocks or home heating oil. Thus as petroleum resources diminsh, 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 8-19 thru 8-21.

Naturally, 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.

### 8.6.1 <u>Yields and Qualities</u>

The yields and qualities shown in Tables 8-19 through 8-21 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 8-19 which compares a typical sidestream cut with 15/5 distillation.*

### 8.6.2 <u>Effect of Improved Distillation</u>

Improving fractionation 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 in the future.

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*This is a laboratory distillation technique which provides fractionation equivalent to a column with 15 theoretical trays and a 5:1 reflux ratio.

# Table 8-19

## Comparison of Current Jet A Fuel Specifications With Virgin Cuts of South Louisiana and Prudhoe Bay Crudes

| | | Current Jet A Specification | South Louisiana | | Prudhoe Bay | |
|---|---|---|---|---|---|---|
| **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 |
| **Composition** | | | | | | |
| 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 |
| **Volatility** | | | | | | |
| Distillation | | | | | | |
| Temp., °F 10% Rec. | Max | 400 | 344 | 334 | 349 | 330 |
| 50% Rec. | Max | 450 | 430 | 446 | 425 | 436 |
| Final B.P. | Max | 572 | 553 | 550 | 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 |
| **Fluidity** | | | | | | |
| 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 |
| **Thermal Stability @ 300/400°F** | | | | | | |
| Coker ΔP MM Hg | Max | 25 | | | | |
| Coker Tube Color Code | Max | 3 | | | | |
| **Combustion** | | | | | | |
| 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 8-20

## Comparison of a Possible Broad Jet Fuel Specification With Virgin Cuts of South Louisiana and Prudhoe Bay Crudes

| | | Possible Broad Specification | South Louisiana | Prudhoe Bay |
|---|---|---|---|---|
| Nominal Boiling Range, °F | | | 290/570 | 290/570 |
| LV% on Crude | | | 35.2 | 27.1 |
| **Composition** | | | | |
| 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 |
| **Volatility** | | | | |
| 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 |
| **Fluidity** | | | | |
| 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 |
| **Thermal Stability @ 250/350°F** | | | | |
| Coker ΔP in Hg. | Max | 12 | | |
| Coker Tube Color Code | Max | 3 | | |
| **Combustion** | | | | |
| Net Heat, Btu/lb | Min | 18,300 | 18,500 | 18,450 |

# Table 8-21

## Comparison of a Possible Broad Specification With Virgin Cuts of South Louisiana and Prudhoe Bay Crudes

| | | Possible Broad Specification | South Louisiana | Prudhoe Bay |
|---|---|---|---|---|
| **Nominal Boiling Range, °F** | | | 280/620 | 280/620 |
| **LV% on Crude** | | | 43.1 | 33.4 |
| **Composition** | | | | |
| 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 |
| **Volatility** | | | | |
| 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 |
| **Fluidity** | | | | |
| 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 |
| **Thermal Stability @ 250/350 °F** | | | | |
| Coker ΔP in Hg. | Max | 12 | | |
| Coker Tube Color Code | Max | 3 | | |
| **Combustion** | | | | |
| Net Heat, Btu/lb | Min | 18,200 | 18,500 | 18,400 |

The reference case in this study is shown in Table 8-19. 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 percent (23.5 vol percent to 31.5 vol percent) and the final boiling point specification is also met. The Prudhoe Bay yield increases by 41 percent (17.1 vol percent to 24.1 vol percent), but still requires treating for aromatics reduction. A summary of key qualities follows.

| | Current Spec. | South Louisiana | | | Prudhoe Bay | | |
|---|---|---|---|---|---|---|---|
| Nominal Boiling Range, °F | | 320/510 (Normal) | 300/550 15/5* | Percent Increase | 330/508 (Normal) | 300/550 15/5* | Percent Increas |
| 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

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 is to say that there is theoretical scope for higher yields of specification product, but practical limitations may prevent these yields from being realized.

### 8.6.3 Broadcut Implications on Yield and Quality

The first broadcut specification examined is shown in Table 8-20. Comparison with current specifications shows that the aromatics content will be higher, the boiling range wider(8-34), 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 percent over the normal cut for current specifications. The yields for Prudhoe Bay have also increased - the normal cut shows a 58 percent increase over the reference cut. However, as the table indicates, the relaxation of the aromatics content specification eliminates the need for further treatment because the Prudhoe Bay quality now falls below the maximum. A key quality summary follows.

| | Broad Spec. | South Louisiana | | | Prudhoe Bay | | |
|---|---|---|---|---|---|---|---|
| Nominal Boiling Range, °F | | 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 | |

## 8.6.4 Additional Broadcut Specification

A further relaxation in specification will increase the theoretical yield even more, as shown in Table 8-21. Here the allowable aromatics content is 40 vol percent, 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 percent - and 83 percent increase over the reference cut. The Prudhoe Bay yield is 33.4 vol percent (normal) an increase of 95 percent over the reference normal cut. Unlike the reference cut, these Prudhoe Bay fractions do not require treating to meet the aromatics content specification. The brief table which follows summarized important qualities.

| | Broad Spec. | South Louisiana | | | Prudhoe Bay | | |
|---|---|---|---|---|---|---|---|
| Nominal Boiling Range, °F | | 280/620 | 320/510 | Percent Increase | 280/620 | 330/508 | Percent Increase |
| Yield, LV% 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, but at the expense of lower yields of other products. Competing demands for the middle of the crude barrel will have to be evaluated in order to determine the total impact of miximizing 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 impact directly on both refinery and end-use energy consumption. Anderson(8-28) 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.

Thus, even though yield increases may be significant, the additional yield may not be readily available to the aviation industry.

## 8.7 Overall Comparison and Ranking

The advantages and disadvantages for $LH_2$ compared to synthetic jet fuel from either coal or shale oil are summarized in Table 8-22. Liquid hydrogen's greatest potential would appear to be for long range flight (greater than 5500 miles) at subsonic speeds or for supersonic flights. These advantages are due to the lighter weight of the $LH_2$ aircraft for a given mission due to the lower weight of the fuel carried. There are also environmental advantages for the $LH_2$ aircraft. The major disadvantages for $LH_2$ are (1) the higher cost of the fuel per flight; (2) resource utilization would be poorer, and (3) airport modifications would be much more expensive.

An attempt has been made to quantify these differences, using a Likert scale, with the following rating system.

Initial Cost

+1 - Initial cost less than a synthetic jet A plane.
0 - Some initial cost as a synthetic jet type.
-1 - Initial cost higher.

Energy Utilization

+1 - Resource requirements. Same as for lowest synfuel case.
0 - 1.1 to 2 times more resource requirement than lowest.
-1- Greater than twice the resource requirement of the lowest synfuel.

## Table 8-22

## Advantages/Disadvantages for $LH_2$ Compared to Synthetic Jet

| Advantages for $LH_2$ | Disadvantages for $LH_2$ |
|---|---|
| ● Lighter weight aircraft than synthetic jet fuel | ● Airport modification to add $LH_2$ would be a major undertaking |
| ● Longer range possible | ● Overall economics unfavorable compared to shale oil based fuel for subsonic and supersonic aircraft. |
| ● Greatest performance advantage is with supersonic flight | |
| ● Emission of CO, $CO_2$, H/C, odor eliminated and $NO_x$ equal to or less(5-21) | ● Overall economics unfavorable with coal based liquids for subsonic-close for supersonic |
| ● Potential reduction in noise and sonic boom. | ● Requires more energy from mine to engine |
| ● Initial cost lower for supersonic aircraft, about same for subsonic | ● Amount of $H_2O$ emitted in flight is higher |
| ● Maintenance cost may be lower | ● Safety of handling $LH_2$ more hazardous than synthetic jet fuel |
| ● Can use shorter runways | |

| | |
|---|---|
| Cost of Fuel/Flight | +1 - Cost of fuel per flight equal to lowest syn fuel case. |
| | 0 - 1.1 to 1.5 times as expensive as lowest cost fuel. |
| | -1 - Greater than 1.5 times as expensive for fuel per flight. |
| Maintenance Cost | +1 - Lower maintenance cost than for a syn fuel aircraft. |
| | 0 - Maintenance cost equal to syn fuel aircraft. |
| Emissions | +2 - Much lower emission than a syn fuel engine. |
| | +1 - Some improvement over a synthetic jet fuel. |
| | 0 - Emission equal to current standards. |
| Cost of Airport Facilities | 0 - Same as for synthetic jet fuels. |
| | -1 - More expensive than synthetic jet fuels. |
| | -2 - Much more expensive than synthetic jet fuels. |
| Public Acceptance of Aircraft | 0 - No change from current aircraft. |
| | -1 - Some reluctance to use aircraft with this fuel. |
| Effect on Foreign Sales | 0 - No effect on foreign sales. |
| | -1 - Some effect on foreign sales. |

The basis for the ratings used are covered in previous sections for the initial cost, energy utilization, cost of fuel per flight. The basis for the other ratings is discussed below.

## Maintenance Cost

Studies by Lockheed(8-29) and others(8-24) have stated that maintenance of hydrogen-fueled aircraft should be simpler and less frequent than for jet-fueled engines because hydrogen mixes so quickly and completely with air and burns clearer. It is assumed that $LCH_4$ would behave similar to $LH_2$.

## Efficiency of Turnaround

Studies by Lockheed(8-30) and Boeing(8-31) on designs of airports using $LH_2$ concluded that the turnaround time would be about the same for $LH_2$ as for synthetic jet fuels.

### Air Pollution Emission

Estimates developed by Lockheed for $LH_2$ and jet A are shown in Table 8-23 and were used as the basis to arrive at the rating shown.

### Noise

A hydrogen-fueled plane would be quieter on takeoff than a jet A fueled plane, but noisier on landing,(8-2) as shown in Table 8-24. Therefore, it was decided to rate all three fuels the same.

### Cost of Airport Modification

The cost to add hydrogen liquefaction facilities would be considerably more expensive than for the type of liquid fuel facilities in use today, based on data discussed in Appendix Volume IIIB. Methane liquefaction would be less costly than $H_2$ liquefaction.

### Public Acceptance

This is purely conjecture, but the general public would probably be more reluctant to fly with cryogenic liquids fore and aft of the cabins, than with jet fuel in the wings.

### Effect on Foreign Sales

If liquid hydrogen fueled aircraft were used, foreign airports would also have to install plants to produce hydrogen and to liquify it. This would be costly. The same would apply for liquid methane. With jet A, the countries could continue to use petroleum or a synthetic fuel.

Each stakeholder would no doubt give a different weight to some of the factors. For this study, an equal weight is assigned to each factor*, as shown in Table 8-25. On this basis, the most attractive fuel would be a shale oil derived synthetic jet fuel, followed by a coal derived jet fuel, liquid methane, and liquid hydrogen the least attractive.

For supersonic aircraft, the changes in Table 8-25 would be in initial cost, where $LH_2$ would have an advantage. The other ratings would remain the same.

## 8.8 Possible R&D Ideas

Some possible areas where R&D may be useful are as follows:

- Studies should be made to define the potential for $LH_2$ and $LCH_4$, using fuel cost information in this study. This would determine the break even distance for subsonic aircraft and the supersonic distance and speed to break even with shale oil derived jet fuel.

*The Laplace criterion is applied.

## Table 8-23

## Noise Comparison: $LH_2$ Vs. Jet A Subsonic Passenger Aircraft

|  | Noise Levels in EPNdB ( ) = FAR 36 Limits |  |  | Area of 90 EPNdB Contour |
|---|---|---|---|---|
| Aircraft | Takeoff | Sideline | Approach | (sq mi) |
| **3000 nmi** |  |  |  |  |
| $LH_2$ | 88.1 (103.8) | 86.4 (106.3) | 97.9 (106.3) | 3.8 |
| Jet-A | 92.7 (105.1) | 86.4 (106.9) | 96.6 (106.9) | 4.1 |
| **5500 nmi** |  |  |  |  |
| $LH_2$ | 89.2 (104.9) | 87.2 (106.8) | 98.4 (106.8) | 4.3 |
| Jet-A | 94.2 (107) | 87.8 (107.6) | 96.7 (107.6) | 4.7 |
| Lockheed L-1011 (Certification tests) | 96.0 (105.6) | 95.0 (107) | 102.8 (107) | 6.6 |

Source: Ref. (8-2)

## Table 8-24

## Air Pollutant Emissions Comparison: $LH_2$ Vs. Jet A Subsonic Passenger Aircraft

| Emission Product | Engine Condition | Estimated Emission Level (g/kG fuel except as shown) | |
|---|---|---|---|
| | | Jet-A | $LH_2$ |
| CO | Idle | 30 | 0 |
| Unburned HC | Idle | 4 | 0 |
| Smoke | Takeoff | 15* | 0 |
| $NO_x$ | Takeoff | 12 | ≤12† |
| $H_2O$ | Cruise | 41.9 lb/nmi | 82.4 lb/nmi |
| Odors | Ground operations | Objectionable | None |

---

*SAE 1179 smoke number.

†Adjusted for the difference between the gravimetric energy densities of Jet-A and hydrogen (a factor of 2.8 in favor of hydrogen).

Source: Ref. (8-2)

Table 8-25

Ratings for Subsonic Aircraft

| | $LH_2$ | $LCH_4$ | Jet A | |
|---|---|---|---|---|
| | | | Shale Oil Derived Jet Fuel | Coal Derived Liquids |
| Initial Cost | 0 | 0 | 0 | 0 |
| Energy Utilization | -1 | 0 | +1 | 0 |
| Cost of Fuel/Flight | -1 | 0 | +1 | 0 |
| Maintenance Cost | +1 | +1 | 0 | 0 |
| Efficiency of Aircraft Turnaround | 0 | 0 | 0 | 0 |
| Air Pollution Emission | +2 | +1 | 0 | 0 |
| Noise | 0 | 0 | 0 | 0 |
| Cost of Airport Modification | -2 | -1 | 0 | 0 |
| Public Acceptance | -1 | -1 | 0 | 0 |
| Effect on Foreign Sales | -1 | -1 | 0 | 0 |
| Total | -3 | -1 | +2 | 0 |

- It would appear that coal liquids produced via the indirect method would have more attractive physical properties than those produced via direct liquefaction. Studies should be made to improve the yield of distillates with Fischer-Tropsch catalyst.

- Storage stability of coal liquids hydrotreated to various levels should be determined.

- Studies should be made on engines that could operate with more aromatic jet fuels. These same engines should be tested with higher nitrogen level fuels to see if they are also effective in reducing $NO_x$ emissions.

- Economic comparisons should be made to see if it would be more economic to modify the fuel system or upgrade coal or shale based fuels to meet the current thermal stability standards.

- Processing alternates (such as chemical treating, clay filtering) to severe hydrotreating to improve storage and thermal stability of shale oil derived fuels should be investigated.

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# 9. DEMAND RELATED ISSUES

## 9.1 Energy Supply/Demand Projections

The demand for, and supply of, fuels for non-highway transportation are parts of the supply/demand system for all transportation, and exist in the context of the future availability and utilization of energy for all purposes. Recent projections by both the Energy Information Administration and the Transportation Energy Conservation (TEC) Division of the Department of Energy were reviewed in order to provide an energy context for the present study.

The various projections are based on different assumptions. The EIA cases consider different rates of economic growth, different levels of recoverable U.S. oil and gas resources, and changes in the real price of imported oil, while the TEC projections consider baseline and conservation cases. Naturally, the different assumptions lead to numerically different estimates of future supply and demand. In spite of the numerical differences, it is possible to infer that the projected increments (by year 2000) in liquid fuel supplies derivable from new and emerging technologies are considerably less than required to sustain the present pattern of domestic energy usage. Hence, one inference (as drawn by EIA) is that "substantial adjustments in patterns of consumption will take place." Such adjustments would not be limited to the transportation sector. Indeed, some displacement of oil from the industrial sector to transportation is a common expectation. Nevertheless, shifts within the transportation subsectors are both possible and likely. Two additional 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.

## 9.2 Military and International Considerations

Historically, the military fuel requirements of the U.S. have been procured both domestically and overseas. Currently, DOD's consumption of energy, including electricity, is about 2% of U.S. energy demand. While the aggregate percentage is small, military demand is concentrated in a small number of products and about 62% of the total is for transportation:

| Transportation Mode | % of Total Demand |
|---|---|
| aircraft | 44 |
| marine | 13 |
| ground | 5 |

At present, the transportation fuels are derived entirely from petroleum. Review of the system of military fuel supply and the special demands placed on military fuels led to two expectations.

- Most of DOD's transportation fuel needs will continue to be met with conventional types of jet and diesel fuel (regardless of raw material source).

- DOD may adopt a unique fuel system if this provides a unique performance advantage.

Competition is a particularly important factor in international markets. Cost, reliability, and availability of product or service are usually key ingredients of international competition, but may be blunted to varying degrees by regulations that, in addition to establishing international standards, tend to limit the rate at which systemic changes can occur.

The introduction of new fuels is not a goal of companies providing transportation services. This fact leads to a general inference that any alternate fuel with properties similar to those of the fuel currently used, which will also minimize capital and operating expenses, will be preferred to an alternate fuel that is dissimilar, thereby causing additional capital expense and handling problems. For each transportation mode, the goal is to provide effective transportation of people or freight as economically as possible.

## 9.3 Institutional Issues and Constraints

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. This creates a situation in which a number of conditions must be satisfied simultaneously if a new system is to be introduced:

(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.

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.

## 9.4 Experiment in Probabilistic Forecasting

The projections made in this study depend on a variety of assumptions. In the case of energy projections, most of the assumptions may be considered "baseline". However, other plausible assumptions could be made, and different projections and conclusions might follow. Hence, the study must deal with the issue of future uncertainty. This was attempted using some of the concepts that underlie a forecasting technique called "cross-impact analysis". However, the purpose was not to generate forecasts per se, but rather 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.

- show how the change of a single assumption (treated as a future "event") can lead to significant changes in the perceived probabilities of other events.

Both Exxon Research and DOE groups participated in the probabilistic forecasting experiments. With one exception, the patterns of response by these groups were very similar. The reason for the exception is not known, but may involve different weightings of correlational and causal factors. The test groups' responses had a different focus and format than are found in most published energy projections, thereby making it possible to derive different implications that may be useful in the contingency or strategic planning of R&D. While this would have to be established by additional work, it is believed that:

- knowing and understanding the assumptions made by individuals concerning energy futures and priorities are important to the resolution of institutional problems.

- there is considerable risk in acting upon direct answers to questions such as "when will Technology 'X' be competitive with current technology?", and that more useful/less risky answers can be provided by probabilistic rather than deterministic methods.

An overall implication of the high level of uncertainty (about energy futures) revealed by the experiment is that "surprises" should be expected. Important characteristics of these "surprises" are:

(a) they are likely to be political events (rather than technological developments).

(b) the precise timing of the events, rather than their nature, may be the main factor that makes them "surprises".

(c) most of the events would have an adverse impact on crude oil supply, and <u>sharp</u> increases in price could occur as a consequence of real shortage.

(d) there will be an impact on institutional barriers (which may be broken in time of crises).

Another implication of the probability of surprises is that the lead-time for obtaining a new source of supply will tend to be more important than the unit cost of the new supply. Put differently, ability to move fast will command an economic premium. Biomass fuels stand to benefit, as do any projects that can be implemented quickly.

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Transportation - Energy Conservation Division
Office of Conservation and Solar Applications
Department of Energy, Washington, D.C.

13. Type of Report & Period Covered FINAL
Sept. 1977-June 1979

14.

15. Supplementary Notes

16. Abstracts

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.

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.

(over)

17. Key Words and Document Analysis. 17a. Descriptors

Alternate Fuels
Marine
Aircraft
Pipeline
Railroad
Prime Movers
Diesel Engines
Gas Turbines
Free Piston Engine
Stirling Engine
Closed Cycle Gas Turbine
Physical Properties of Alternate Fuels
Otto Cycle Engines
Nuclear Power
Fuel Cells
Direct Solar Radiation
Energy Supply/Demand
Institutional Issues
Environmental Impact
Resource Requirements
Energy Efficiency in Use
Economics of Production
Transportation Cost

17b. Identifiers/Open-Ended Terms

17c. COSATI Field/Group

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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 report 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.