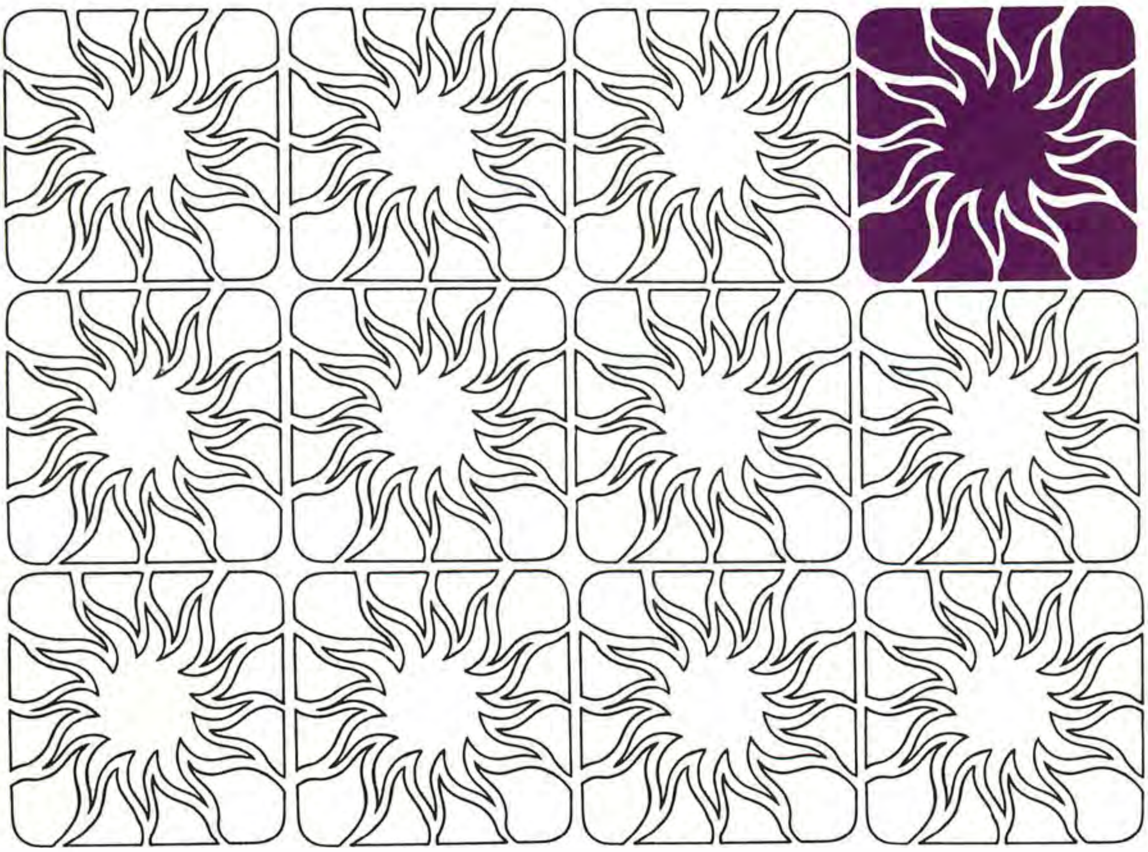
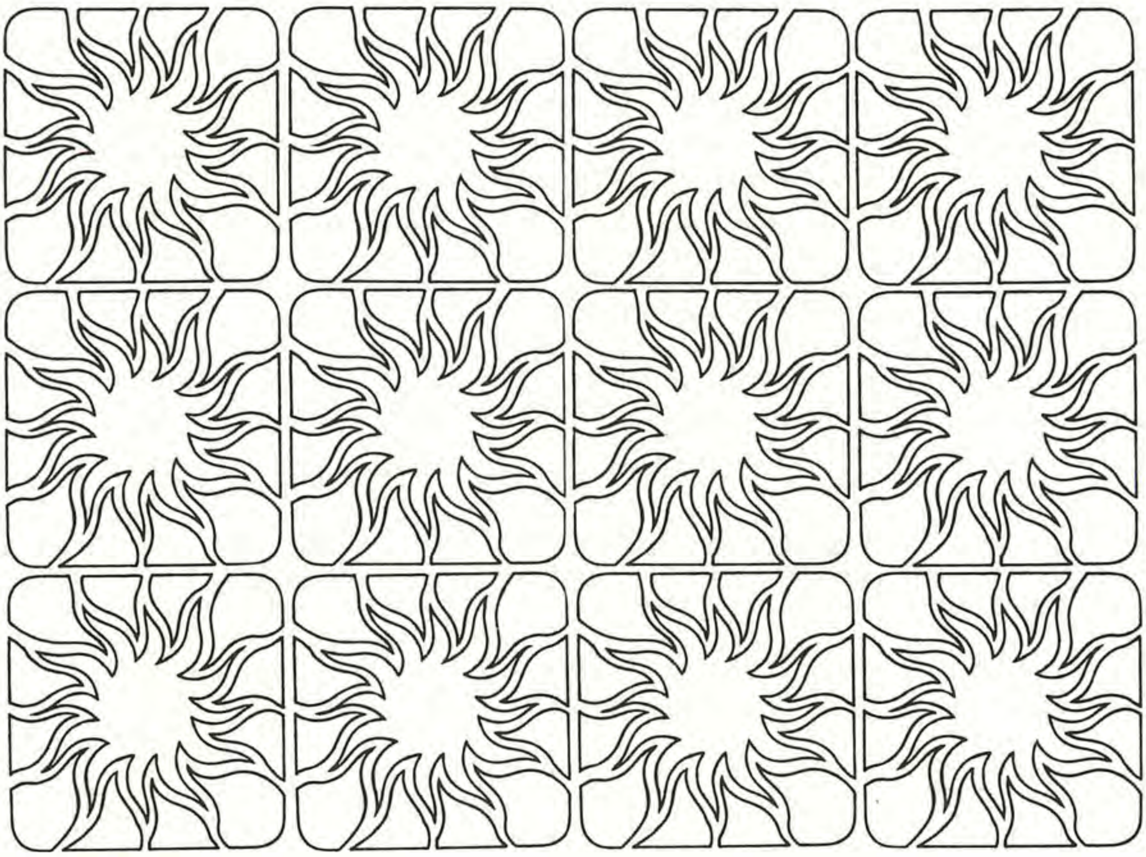


U.S. Energy Outlook

New Energy Forms

National Petroleum Council



U.S. Energy Outlook

New Energy Forms

A Report by the
New Energy Forms Task Group of the
Other Energy Resources Subcommittee
of the National Petroleum Council's Committee
on U.S. Energy Outlook

Chairman - Olaf A. Larson
Gulf Research and Development Company

National Petroleum Council

NATIONAL PETROLEUM COUNCIL

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PREFACE

On January 20, 1970, the National Petroleum Council, an officially established industry advisory board to the Secretary of the Interior, was asked to undertake a comprehensive study of the Nation's energy outlook. This request came from the Assistant Secretary-Mineral Resources, Department of the Interior, who asked the Council to project the energy outlook in the Western Hemisphere into the future as near to the end of the century as feasible, with particular reference to the evaluation of future trends and their implications for the United States.

In response to this request, the National Petroleum Council's Committee on U.S. Energy Outlook was established, with a coordinating subcommittee, four supporting subcommittees for oil, gas, other energy forms and government policy, and 14 task groups. An organization chart appears as Appendix B. In July 1971, the Council issued an interim report entitled *U.S. Energy Outlook: An Initial Appraisal 1971-1985* which, along with associated task group reports, provided the groundwork for subsequent investigation of the U.S. energy situation.

Continuing investigation by the Committee and component subcommittees and task groups resulted in the publication in December 1972 of the NPC's summary report, *U.S. Energy Outlook*, as well as an expanded full report of the Committee. Individual task group reports have been prepared to include methodology, data, illustrations and computer program descriptions for the particular area studied by the task group. This report is one of ten such detailed studies. Other fuel task group reports are available as listed on the order form included at the back of this volume.

The findings and recommendations of this report represent the best judgment of the experts from the energy industries. However, it should be noted that the political, economic, social and technological factors bearing upon the long-term U.S. energy outlook are subject to substantial change with the passage of time. Thus future developments will undoubtedly provide additional insights and amend the conclusions to some degree.

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FOREWORD

This report was prepared by the New Energy Forms Task Group under the direction of the Other Energy Resources Subcommittee of the National Petroleum Council's Committee on U.S. Energy Outlook.

The purpose of the report is to discuss the contribution that can be made to the Nation's energy requirements by (1) energy resources which are projected to provide relatively little usable energy during the 1971-1985 period as compared with the major resources--oil and gas, coal, nuclear energy, oil shale and tar sands, (2) processes which can increase the efficiency of fossil-fuel energy utilization for the generation of electric power and (3) alternative or unconventional energy forms.

The Task Group investigated hydropower--a primary energy resource, the full potential of which is largely developed--and geothermal energy, which is generally undeveloped at present but will make a larger though relatively insignificant contribution by 1985. Utilization of other primary energy resources investigated--agriculture, solar, tidal and municipal trash--are still in the research and development stage.

Since the effective supply of energy can be increased by improving efficiency in energy conversion to electricity, the Task Group investigated the potential for advanced conversion systems--combined cycle (gas turbine-steam turbine), magnetohydrodynamics (MHD), fuel cells and thermionic electric power generation.

As an alternative to coal conversion to oil or conventional pipeline gas (methane), the Task Group investigated conversion to methanol (methyl alcohol) or hydrogen and compared the economics of these usable forms with petroleum products.

Considering the time and investments required for development and the history of utilization of new energy resources in the United States, the Task Group sees little possibility that new forms not already in an advanced state of development will have a significant impact on energy supply in this century.

Part One

Introduction, Summary and Conclusions

Chapter One

ENERGY RESOURCES, CONVERSION AND ALTERNATIVE FORMS

BACKGROUND

The National Petroleum Council's report on U.S. Energy Outlook, published December 1972, concluded that it is unlikely that the growth in energy consumption in the United States will depart significantly from an average of a 4.2-percent-per-year rate during the 1971-1985 period. A range of 3.4 to 4.4 percent embraces the probable changes that might take place. Any of these energy demand cases represent much more than the supply which will be available from U.S. indigenous resources.

Figure 1 illustrates the high, low and intermediate demand projections for 1985, as well as the four supply cases. Most of the differences between the supply cases are in the projected domestic oil and gas supply. Oil and gas availability will be greatly affected by the finding rate (reserves per unit of drilling) and by the rate of exploration (drilling) which, in turn, is strongly influenced by the political and economic climate.

Certain policies and administrative judgments (e.g., early resolution of environmental issues) would improve the prospects of attaining a high rate of growth for all principal fuel supplies (i.e., oil and gas, coal and nuclear). This would also accelerate oil shale development, moving an important resource into the supply picture.

The high end of the calculated supply range (Case I) assumes a reversal in recent trends in drilling activity (prior to 1971) and an expansion equal to that achieved in the post-World War II decade coupled with a high finding rate. Case I would be difficult to attain because it requires a vigorous effort fostered by early resolution of controversies about environmental issues, ready availability of government land for energy resource development, adequate economic incentives and a higher degree of success in locating currently undiscovered resources than has been the case in the past decade. The low end of the range of supply availability (Case IV) projects a continuation of the historical downward trend in drilling activity with a low finding rate. Case IV represents a likely outcome if disputes over environmental issues continue to constrain the growth in output of all fuels, if government policies prove to be inhibiting and if oil and gas exploratory success does not improve over recent results. Cases II and III are intermediate cases representing a medium growth rate in drilling activity with Case II projecting the high finding rate and Case III the low finding rate. The National Petroleum Council's report, *U.S. Energy Outlook: An Initial Appraisal*, published in 1971, which assumed a continuation of existing conditions, projected oil production rates in 1985 to be approximately that of Case III and gas production rates to be approximately that of Case IV.

Since the growth potential of primary hydropower is very limited by available sites, only one growth case was considered. The four cases presented for geothermal energy reflect wide variations in possible exploration and drilling success. Case III is identical to that published in the Initial Appraisal which was based on existing trends in the California geysers area.

Figure 1 shows the relatively small contribution that hydro- and geothermal power will contribute to the energy supply in 1985. Figure 2 shows that a modest growth is expected during the 15-year period for the two intermediate cases.

Table 1 shows numerically in terms of BTU (British thermal units) supply/demand balance for Case I that hydropower is projected to grow from 2,677 trillion BTU's in 1970 to 3,320 trillion BTU's in 1985. Since energy consumption in the United States is projected to nearly double during this period, the hydropower percentage contribution will decrease from about 4 percent to less than 3 percent. Hydropower represents a form of primary energy, the full potential of which has largely been developed.

Table 1 shows that geothermal power, which contributed only 7 trillion BTU's in 1970, is projected for Case I to 1,395 trillion

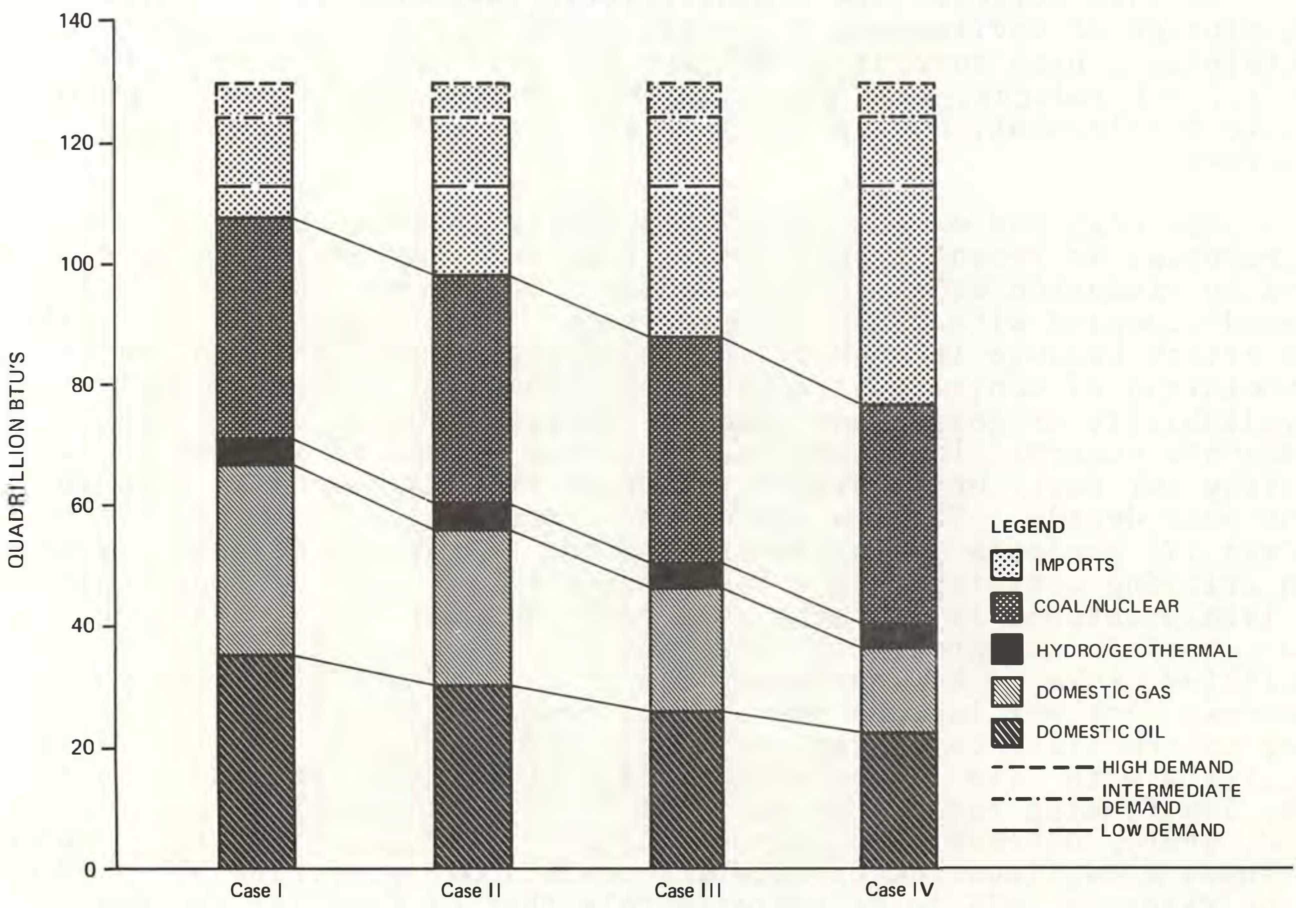


Figure 1. U.S. Energy Supply and Consumption in 1985.

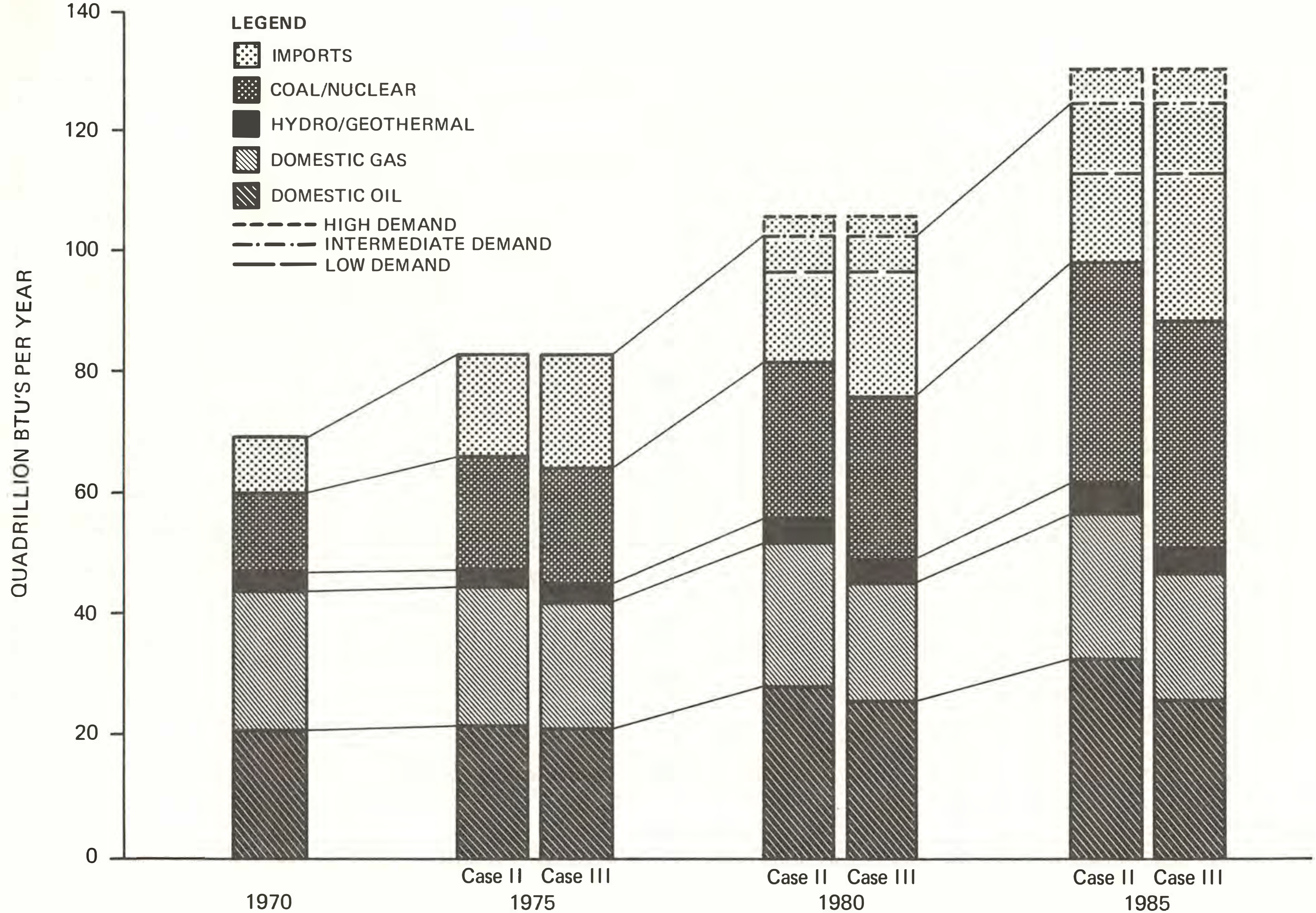


Figure 2. Energy Supply and Consumption, Cases II & III.

TABLE 1

PROJECTED ENERGY BALANCE FOR UNITED STATES—CASE I

	Trillion (10^{12}) BTU's/Year				Percent			
	Actual	Projected			Actual	Projected		
	1970	1975	1980	1985	1970	1975	1980	1985
Domestic Supply								
Oil—All Sources	21,048	20,735	28,229	34,656	31	25	27	28
Gas—All Sources	22,388	24,513	27,464	35,214	33	29	27	28
Hydropower	2,677	2,990	3,240	3,320	4	4	3	3
Geothermal	7	120	782	1,395	*	*	1	1
Coal & Nuclear Utilized	13,302	18,649	26,708	36,910	20	22	26	29
Total Domestic Supply	**59,422**	**67,007**	**86,423**	**111,495**	**88**	**80**	**84**	**89**
Imported Supply to Balance								
Oil Including Liquids for Gasification	7,455	15,274	12,258	7,547	11	18	12	6
Gas (Excluding Gas from Liquids)	950	1,200	3,900	5,900	1	2	4	5
Total Imported Supply	**8,405**	**16,474**	**16,158**	**13,447**	**12**	**20**	**16**	**11**
Total Domestic Consumption	**67,827**	**83,481**	**102,581**	**124,942**	**100**	**100**	**100**	**100**
Memo: Coal Supply	13,062	16,650	21,200	27,100	98	81	65	48
Nuclear Supply	240	4,000	11,349	29,810	2	19	35	52
Total Coal & Nuclear Available	**13,302**	**20,650**	**32,549**	**56,910**	**100**	**100**	**100**	**100**
Memo: Oil Supply								
Domestic Conventional	21,048	20,735	27,758	31,689	74	58	69	74
Syncrude from Shale	0	0	296	1,478	0	0	1	4
Syncrude from Coal	0	0	175	1,489	0	0	*	4
Imports (Including Liquids for Gasification)	7,455	15,274	12,258	7,547	26	42	30	18
Total Oil	**28,503**	**36,009**	**40,487**	**42,203**	**100**	**100**	**100**	**100**
Oil Imports to Balance—MMB/D	3.4	7.2	5.8	3.6				
Memo: Gas Supply								
Domestic Natural Gas	22,388	24,513	26,746	31,604	96	95	85	76
Gas from Nuclear Stimulation	0	0	206	1,341	0	0	1	3
Syngas from Coal	0	0	512	2,269	0	0	2	6
Imports—Pipeline	950	1,000	1,600	2,700	4	4	5	7
Imports of LNG	0	200	2,300	3,200	0	1	7	8
Total Gas (Excluding Gas from Liquids)	**23,338**	**25,713**	**31,364**	**41,114**	**100**	**100**	**100**	**100**
Gas Imports—TCF/yr	0.9	1.2	3.9	5.9				

* Less than 0.5 percent.

BTU's in 1985, or about 1 percent of U.S. consumption. Geothermal energy is largely undeveloped at present, but even with the projected 200-fold increase, which is extremely optimistic, the 1985 contribution will be relatively insignificant.

It is very unlikely that the potentially available solar energy will be exploited significantly within the time frame of this study.

Potential energy resources from agriculture, if fully developed, could be substantial but do not offer an economical alternative in the near term. The possibilities for harnessing tidal energy in the United States are extremely limited. Municipal trash is being used as a primary boiler fuel in a few locations. If the total U.S. municipal trash potential were utilized, it could supply about 3 percent of the fuels for electricity in 1980.

The combined-cycle process for generating electric power is the technological innovation most likely to make a real impact on the efficiency of fossil-fuel utilization. In the order of their potential importance by 1985, other processes likely to boost electric power generation from the same amount of fuel are: (1) gasification of coal for combined-cycle and (2) fuel cells. Magnetohydrodynamics and thermionic topping of fossil-fuel power plants, if successful, are likely to appear after 1985.

In considering the impact of new primary energy resources on the energy supply mix, it is useful to consider the history of resource exploitation in the United States. As shown in Figure 3, this country has needed and developed a new source of energy every 30 or 40 years. First, after wood, wind and waterwheels, it was coal. Although the use of coal began around 1780, it was not until 1870, after the development of several of the more modern energy-consuming machines such as steam engines, locomotives, cotton gins, power looms, lathes and steel mills that coal became important.

Gas came next in 1816 and was the basis for the flourishing glass industry in the 19th century. But this, too, did not become important until many years later when, in the 1930's, it became possible to pipe natural gas long distances to market. This accelerated after World War II.

Oil was discovered in 1859, but it did not become an important item of commerce until 1901 when Spindletop made cheap oil available for locomotives, and then in 1919 when the self-starter was invented and the mass production of internal-combustion engines began.

The next new source of energy was hydroelectric power in 1890. This followed the invention and development of electric power generators and their commercialization with the building of the first steam-electric power plant in New York City in 1883.

After that development, over half a century elapsed before another new source of energy--nuclear fission--was discovered.

This became commercial with the building of the first prototype plant in Shippingport, Pennsylvania, in 1957.

Now, if history is an indicator of the future, it is quite reasonable to expect that another energy resource will begin to make itself felt before the year 2000, just about 30 years from now. This could be nuclear fusion, solar energy or possibly (although unlikely) some other resource not yet discovered. Whether it is nuclear fusion, solar, deep geothermal, or whatever, a great deal of diligent research and many years of development will be required before the United States can enjoy these potential resources.

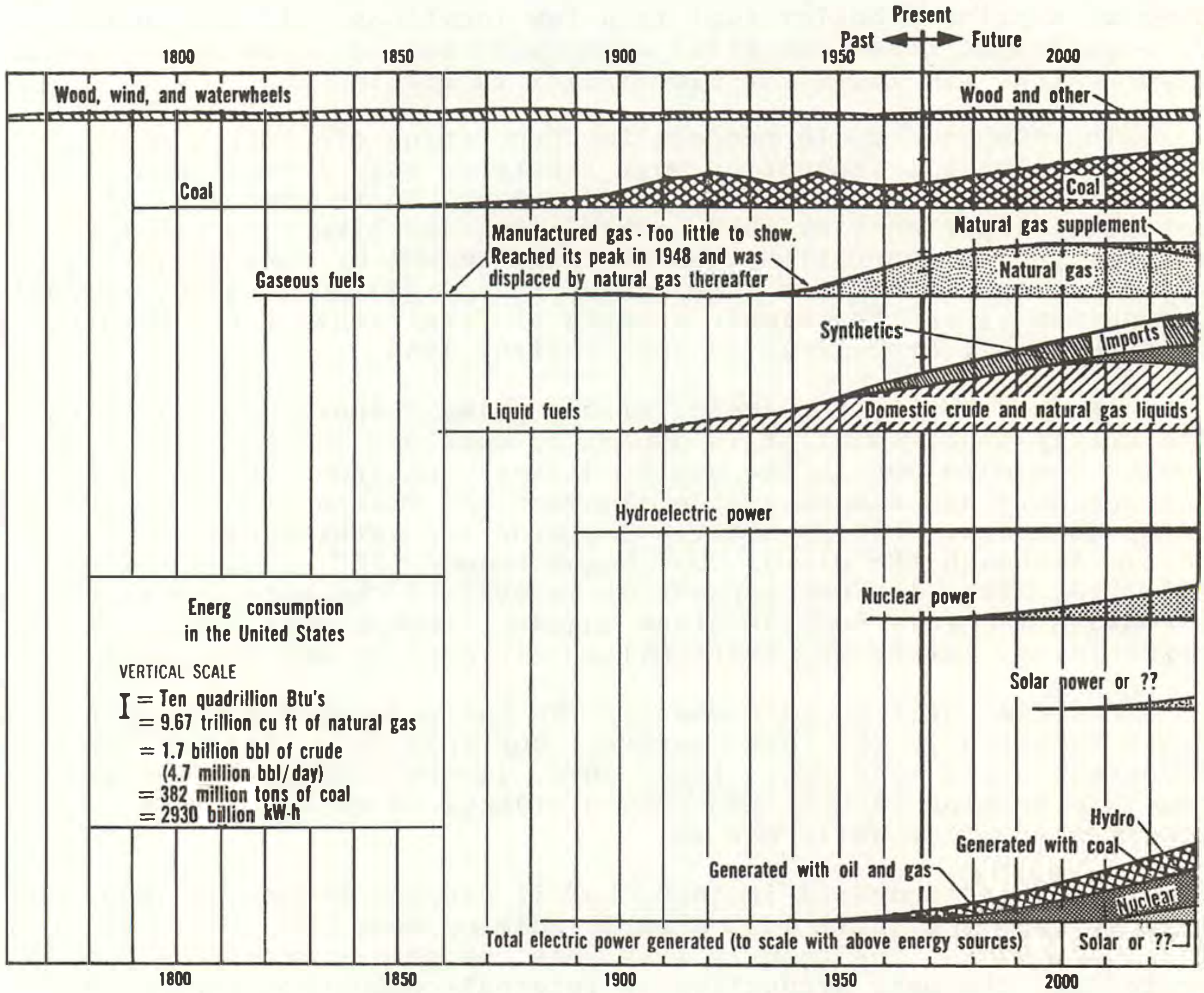


Figure 3. Chronological Energy Conumption in the United States.

SUMMARY AND CONCLUSIONS

ENERGY RESOURCES

Hydroelectric Energy

Good sites for hydropower dam construction in the United States have largely been developed, and only scattered small sites remain. Therefore, the use of hydropower will grow more slowly than use of other energy sources, declining to a 3-percent share of national energy requirements by 1985.

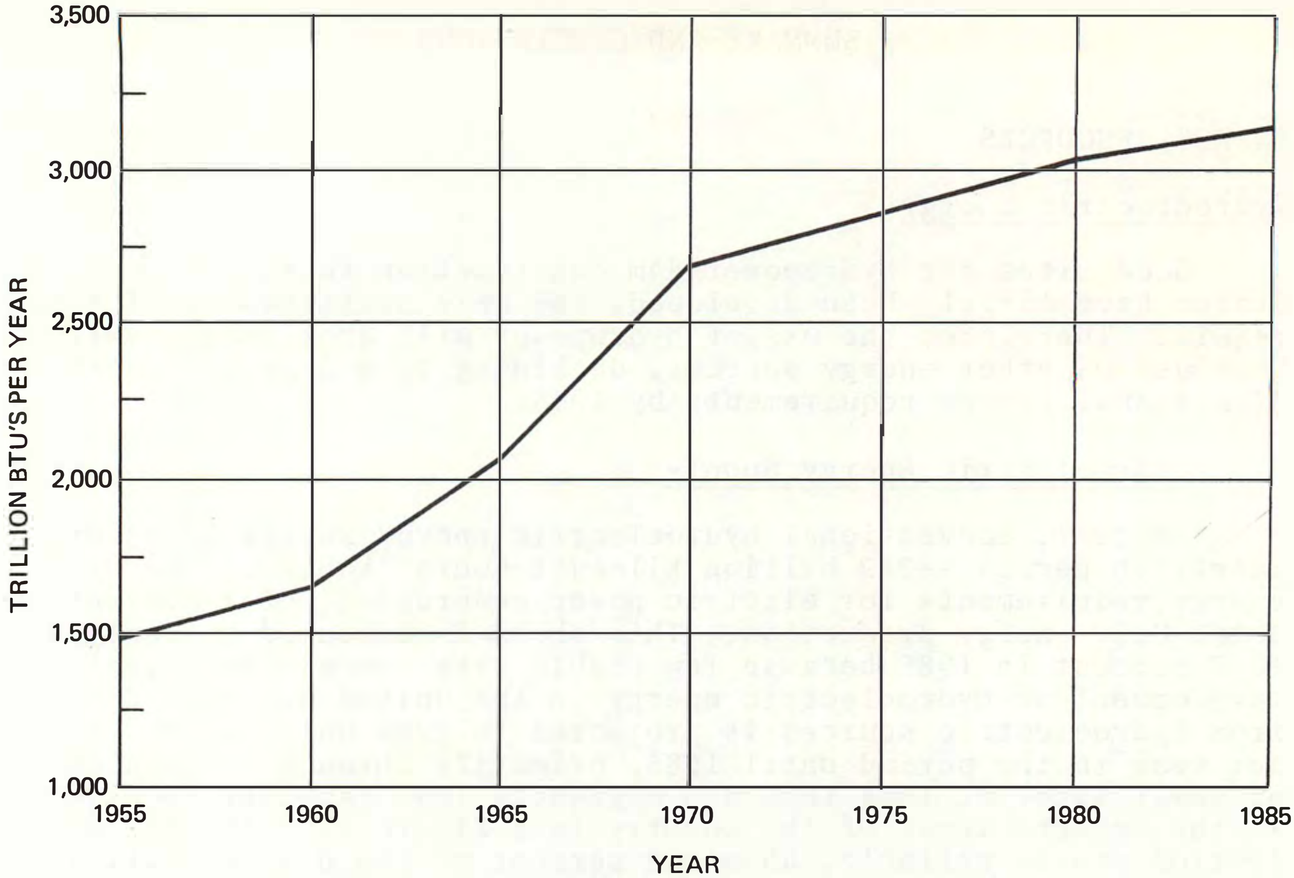
Hydroelectric Energy Supply

In 1971, conventional hydroelectric energy supplied approximately 16 percent--249 billion kilowatt hours (KWH)--of the U.S. energy requirements for electric power generation, or 4 percent of total U.S. energy production. This share is expected to decline to 3 percent in 1985 because few usable sites remain for significant development of hydroelectric energy in the United States. Energy from hydroelectric sources is projected to grow only 1.6 percent per year in the period until 1985, primarily through development of small sites of less than 200 megawatts (MW) capacity located in the western areas of the country (see Figure 4). If this projection proves reliable, about 60 percent of the U.S. potential conventional hydroelectric energy will have been harnessed by 1985, with the undeveloped potential consisting of widely scattered small sites that may never be developed because of economic reasons. The somewhat doubtful economic feasibility of small sites, as well as the impact of environmental regulations, may make even the projection of 60 percent optimistic.

Pumped-storage hydroelectric plants will find increasing use by 1985 as an economical way of *storing* energy (not as a primary energy source). Nuclear power plants will serve as the primary energy source and in off-peak hours will pump water into storage reservoirs. Since they will be used for peak-load power generation, the pumped-storage plants will compete with the gas turbine generators which are now largely used for that purpose.

Geothermal Energy

Where underground water sources are in close enough proximity to hot portions of the earth's crust, the resulting steam can be utilized to drive conventional steam turbine generators. Efforts are also being made to use hot geothermal water with a heat exchange system. However, even if geothermal energy sources (steam wells, hot water) are developed at a relatively optimistic rate, they probably will supply only 1 percent of U.S. energy requirements in 1985. Projection of energy to be derived from geothermal sources is subject to great uncertainty.



SOURCE: NPC, U.S. Energy Outlook: An Initial Appraisal 1971-1985, *Vol. I and II (1971).*

Figure 4. Total U.S. Energy from Conventional Hydroelectric Sources.

Geothermal Energy Supply

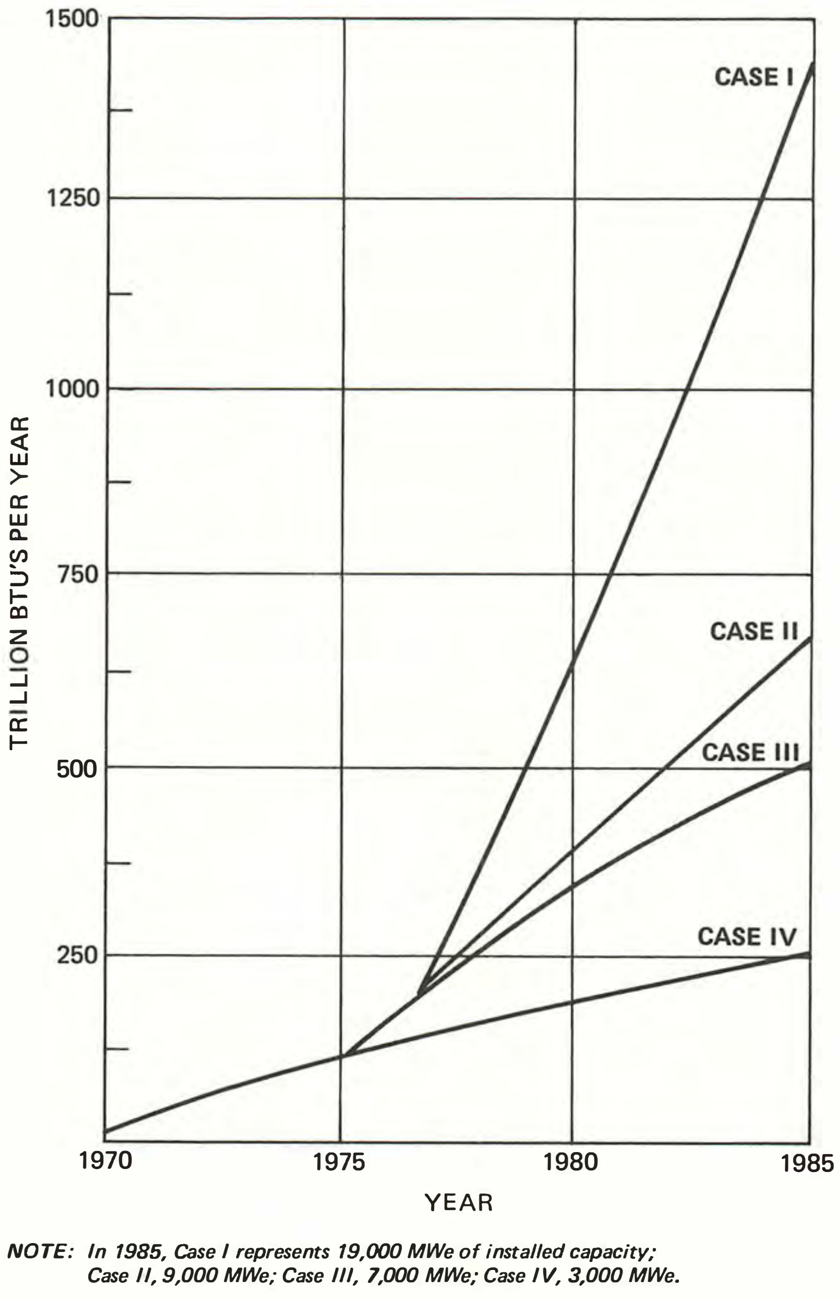
Cases I through III assume that large areas will be available for prospecting, including the recently opened federal lands, to encourage exploration in the next 4- to 5-year period. Case III is identical to the Initial Appraisal estimate, and Case IV is a 50-percent reduction of Case III.

The success ratio in exploration and drilling during the next 4 to 5 years will have a vital bearing on future exploration and, accordingly, total energy from localized geothermal resources. No experience presently exists with respect to the finding rate as a function of total area explored or the number of feet drilled. Variations in the success ratio for dry-steam reservoirs, similar to the Geysers area in northern California, are reflected in the curves in Figure 5 which show energy projections for geothermal energy. The Case III curve, which shows 7,000 MW being developed by 1985, could be reduced as much as 50 percent with poor success in exploration and drilling in new areas. This possibility results in the Case IV projection of 3,500 MW by 1985. If the success ratio is particularly good, increases could be about 25 percent above the Case III projection. This is shown in Case II which indicates a level of 9,000 MW by 1985. The top curve (Case I) assumes that technology for hot water systems will be available in 1977.

Parameters Affecting Geothermal Energy Supply

By 1985, a level of proved *recoverable* heat reserves could be established, ranging from 29 to 290 quadrillion BTU's (see Table 2), provided that existing constraints (as identified in Table 3) are resolved.

The potentially more important geothermal targets are deep sedimentary basins, cratons and platforms, and shallow magma chambers. The main constraining factors, which vary with the type of target, are (1) uncertainty about the magnitudes of the recoverable reserves



***NOTE:** In 1985, Case I represents 19,000 MWe of installed capacity; Case II, 9,000 MWe; Case III, 7,000 MWe; Case IV, 3,000 MWe.*

Figure 5. Total U.S. Energy from Geothermal Sources.

TABLE 2

IN SITU* HEAT RESOURCES
(Quadrillion BTU's)

Geothermal Target	Reserve Target for 1985	Resource Base
Localized Hydrothermal Systems, down to 2 Miles Deep	5.6	560
Localized Hydrothermal Systems, down to 6 Miles Deep	2.8	2,800
High-Enthalpy Waters, Sedimentary Basins	119	64,000
Magma Chambers, Within Depths of a Few Miles	119	120,000 – 400,000
Low-Enthalpy Waters, Sedimentary Basins	635	640,000
Cratonic and Platform Areas, down to 6 Miles	2,000	20,000,000

* For comparison, heat of combustion of 1 barrel of oil is 5.8 million BTU's. The *recoverable* amounts of heat are one to two orders of magnitude lower than the *in situ* figures shown in this table.

and resource bases and (2) insufficient or absence of research and development on certain technical questions.

- Lease Costs: At present, lease costs and landowner royalties are below those currently paid by the petroleum industry. However, success in developing geothermal resources will stimulate competition for leases and will likely cause these costs to increase.

- Exploration Technology: At the present time there is no exploratory tool for locating geothermal deposits such as the reflection seismograph used for locating oil and gas structures. There are several geophysical methods being

TABLE 3

CONSTRAINTS TO GEOTHERMAL RESOURCE DEVELOPMENT

Geothermal Target	Current Constraints	Subsequent Constraints	Outer Contingency
Localized Hydrothermal Systems down to 2 Miles Deep	Leasing, Exploration Economics	Small Resource Base	Air and Water Pollution
Localized Hydrothermal Systems down to 6 Miles Deep	Economics	Leasing, Exploration	Air and Water Pollution
High-Enthalpy Waters Sedimentary Basins	Exploration, Deep Drilling	Economics	Brine Disposal and Utilization
Magma Chambers Within a Depth of a Few Miles	Exploration R&D Magmas	Economics	Unknown
Low-Enthalpy Waters Sedimentary Basins	R&D, Power Generation	Exploration, Economics	Brine Disposal and Utilization
Cratanic and Platform Areas, down to 6 Miles	R&D, Plowshare	Economics	Radioactive Pollution

used, but with limited success. Progress depends primarily on the ability to drill deeper exploratory holes.

- Depletion Allowance: Estimates which have been made for the development rate of geothermal energy are based on the assumption that the depletion allowance of 22 percent will continue to be in effect. If the depletion allowance were abolished, the average cost of steam will increase from 2.75 to 3.10 mills per KWH. Although this would not affect power costs significantly, it would discourage the development of some geothermal areas.

- Environmental Impact: It is expected that geothermal energy development will have few environmental effects. However, the time required to develop environmental impact statements and handle possible lawsuits and the threat of court injunctions would significantly slow the pace of geothermal exploration and development.

- Productivity: In most of the future fields, condensed steam and hot water will have to be injected into the ground and, in many cases, directly back into the reservoir. Although this has been accomplished experimentally in both dry-steam and hot-water fields, the effects on reservoir pressures and temperatures are not yet known. If the productivity of a field is adversely affected by injection, it may be offset by increased longevity of production.

Agricultural Energy

The efficiency of U.S. agriculture has advanced so fast that for several decades crop production, except in times of international conflicts, has exceeded demand. Average farm production has increased about 80 percent in the last three decades, largely owing to better yielding seeds and greatly improved "know-how." Thus, to meet our crops' needs, we have planted fewer acres and required fewer farmers.

Agriculture provides the major current source of renewable energy. Forests, cultivated crops and pasture land may be used repeatedly under proper management. Agricultural production is, however, subject to weather, diseases and other natural conditions which cannot yet be completely controlled. Nevertheless, average production in excess of priority requirements for domestic food, feed and fibers is believed possible to 1985 and beyond. The production of cereal grains and their conversion through fermentation to usable ethyl alcohol fuel; the collection and use of such residues as straws, corncobs, hulls and shells for fuels; the growing of crops for fuel energy; and the conversion of animal by-products into fuels are all possibilities.

Agricultural fuels would normally be more expensive than such traditional fuels as coal, gas, oil and waterpower. Increasing

U.S. needs for energy could, however, materially change the future role of agriculture as a source of industrial energy.

Of the approximately 2,260 million acres of U.S. land available, about 25 percent is classified as forest and woodland and about the same proportion as land suitable for cultivation. Most of our woodland will probably be required to meet the predicted demands for the lumber, pulp and paper industries, and thus will offer only minor possibilities for contributing to additional U.S. industrial energy supplies. On an average, only about 60 percent of the potentially available cultivated land is now farmed for crops. Yields of cereal grains on these lands have increased about 3 percent annually for the past decade. This increase has exceeded the U.S. population growth, even though the amount of cultivated land has decreased. Thus, unused acres constitute a potential source of energy for the foreseeable future.

A logical sequence of energy conversions is to use this land to produce cereal grains, which are largely carbohydrate, and then to convert these grains by fermentation into ethyl alcohol, which is a convenient combustible fuel readily usable in motors. If we assume that 100 million acres are used to produce the grain for alcohol at a yield of 70 bushels per acre, this would be equivalent to about 18 billion gallons of alcohol, or on the order of 20 percent by volume (14 percent in BTU value) of the approximately 90 billion gallons of motor fuel consumed in the United States in 1971. Since ethyl alcohol contains 65 percent of the energy content of gasoline, on a gallon basis, the actual energy replacement would be 14 percent.

The quantity of collectible agricultural residues in the United States amounts to 196 million tons annually. The heat equivalent of this amount would be on the order of 3,000 trillion BTU's--or 3 percent of the 1980 U.S. demand. These agricultural residues with all their potential energy could not now compete economically with such traditional fuels as coal or oil. The growing of crops specifically as an energy source is a possibility but is not attractive. The production of synthesis gas (500 BTU/cubic foot carbon monoxide and hydrogen) from agricultural residues or from crops grown specifically for energy is also a possibility. Synthetic liquid or pipeline gas can be made from synthesis gas with partly known technology. Additional research and development work would be required for the gasification of agricultural material.

Although the total potential energy from agricultural residues is large, it is doubtful that these sources can have a significant effect on the U.S. industrial energy picture by 1985. A great deal more research and development (R&D) than is now underway would be required on specific production of grains for industrial alcohol or specific crops grown for high energy productivity per acre. Concurrent research would be required on the complex social and economic effect of committing a large percentage of agricultural production to industrial alcohol and the resulting tremendous supply of protein.

Solar Energy

Utilization of the sun's tremendous energy is not feasible by present technology because of the very high capital cost of the devices available to convert solar energy to electric energy. The large amount of area required to collect solar energy, and the cost of the collection, storage and conversion equipment, prevent the widespread use of solar heaters, solar ponds, solar evaporators, solar desalinators, solar cookers, solar furnaces, solar cells and solar houses. The heat storage problem--that is, making heat available at night and on cloudy days--is a great complicating factor.

A major R&D effort will be required to learn how to utilize a broad section of the solar spectrum rather than just the narrow band limitations of present technology if solar energy is to become a significant energy supply. Little progress is expected in making such a technological breakthrough by 1985.

Tidal Energy

Tidal energy was used before 1800 to operate a 50-horsepower mill at Chelsea, Massachusetts, near Boston, and other mills on Passamaquoddy Bay, Maine. Wide exploitation of tidal energy is limited by the tidal range which varies from 18 feet at Eastport, Maine, on Passamaquoddy Bay, the Canadian border and in Cook Inlet, Alaska; to 4 feet south of Cape Cod and at San Diego; 2 feet along the coast of Florida; and less than 2 feet in the Gulf of Mexico. Since available energy from tides is a function of the square of the tidal range, only specific bays in Alaska and Maine have enough range to warrant serious consideration of tidal power utilization in the United States.

The potential tidal energy from the U.S. part of Passamaquoddy Bay is very low and could be captured only as a part of a much larger project in collaboration with Canada. Cook Inlet has a very large potential but also numerous complicating factors which would make a project very costly. Some of these are deep water at the mouth, high silt content, drift ice and earthquake probabilities.

Considering the small resource potential and high cost of development, it is unlikely that tidal energy will be utilized in the United States by 1985.

Municipal Trash

Some 200 million tons of trash are collected yearly by towns and cities in the United States. Since the energy content is about 8 million BTU's per ton, this represents a 1,600 trillion BTU's per year energy resource, or in the order of 1-1/2 percent of the U.S. 1980 projected consumption. The most attractive way to use municipal trash is as boiler fuel for power generation. Such an advanced design system burns 400 tons of waste per day to generate

15 megawatts of electricity and 82,300 pounds per hour steam. If all municipal trash were thus utilized, it would fuel 21,000 MW--or about 3 percent of the Federal Power Commission's 1970 projection for 1980 installed capacity, plus a substantial amount of steam for heating.

It will be impossible, of course, to burn all U.S. city and town trash under boilers for electric generation. As the cost of energy supply goes up, trash for fuel will become more attractive. However, since the paper content of municipal wastes and trash represents about 65 percent of its heating value, when more paper products are salvaged for recycling, the value of trash as fuel will go down.

There will probably be a trend toward more cities burning trash for boiler fuel as a means of disposal that produces useful products. The resource base is too small to have a significant impact on the U.S. energy supply.

ENERGY CONVERSION TO ELECTRIC POWER

Combined Cycle

In order to affect significantly the national average efficiency of electric power generation in 1985, new innovations would have to be technologically proved already. This is because existing electric generating plants have a life span of several decades, and new plants have long construction lead times. Only one such technological innovation--the gas turbine and steam turbine combined-cycle plant (Brayton-Rankine)--is currently available. This plant utilizes waste heat from large gas turbines to generate steam for conventional steam turbines. Its advantage is that it generates more electricity from the same amount of fuel than does a gas turbine powered generating unit. The best combined-cycle plants that might be built in 1985 are projected as using almost 30 percent less fuel per KWH generated than conventional plants being built in 1972. Nevertheless, due to the large number of existing plants, the national "heat rate" (BTU requirements per KWH generated) is projected to decline only 8 percent from 10,666 BTU's per KWH in 1972 to 9,800 BTU's per KWH in 1985, as shown in Figure 6. This estimate is based on projected new fossil-fuel conventional steam plant installations of 20,000 MW per year in 1975 reducing to 15,000 MW per year in 1985. Combined-cycle plant installations could possibly grow from zero in 1972 to 2,000 MW per year in 1975, 8,000 MW per year in 1980 and 9,000 MW per year in 1985.

Gasification of coal to low-BTU gas is not likely to be economical prior to 1985 for most existing steam-electric utilities and large industrial plants. However, when compared to the cost of stack gas scrubbing processes or the burning of clean fossil fuels, gasification of coal for use in newly constructed combined-cycle plants will probably be economically attractive during this time period.

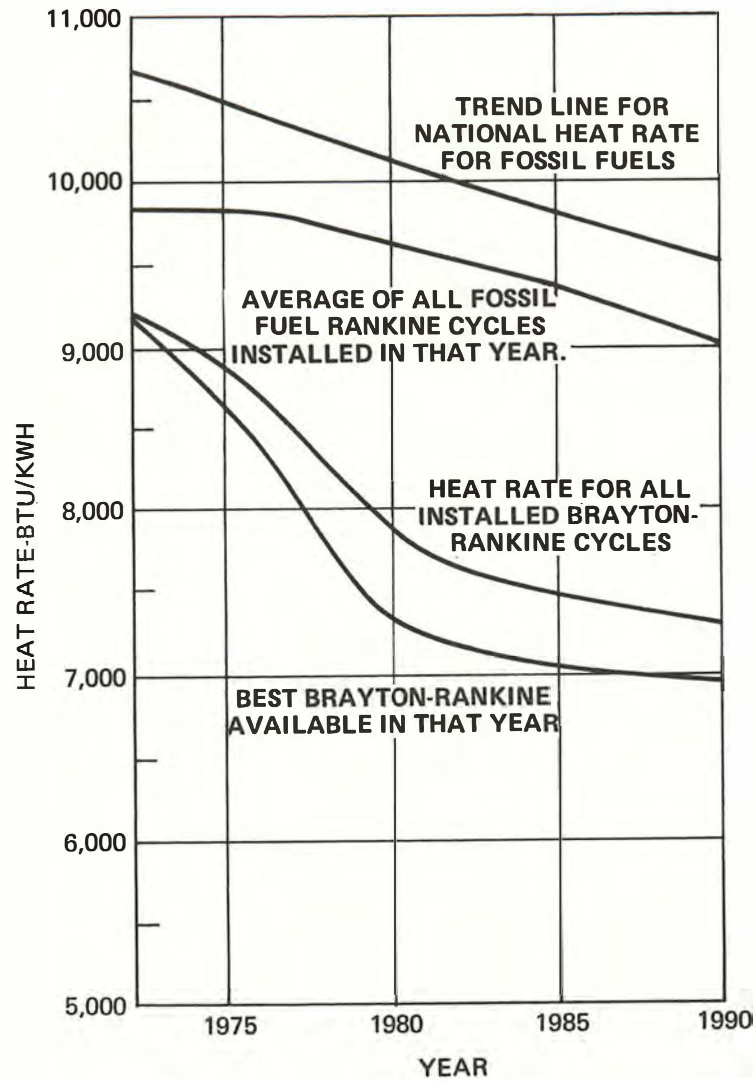


Figure 6. Estimated Trends for Efficiency of Electric Power Generation from Fossil Fuels--1972-1990.

Fuel Cells

Fuel cells might find widespread commercial application by 1985. However, fuel cells with current technology are no more efficient than other means of generating electric power, and they are unlikely to have a major effect on total energy requirements. Fuel cells save on transmission costs but incur transportation and handling costs by shifting the point of electricity generation from central stations to the point of consumption. Commercial testing of fuel cells should be completed by 1975, but their broad application will have to wait until a technological breakthrough is made in the development of cheap catalysts. A high-temperature coal-fired fuel cell development showed promise as a low cost power generation system but was discontinued because of the very short life electrolyte. Small natural gas or methanol-fired fuel cell-total energy systems (12.5 KW) may be competitive with internal combustion engine-total energy systems in the future.

Total Energy Plants

Total energy plants utilize hydrocarbon fuels to drive electric generators to meet electrical needs in a relatively small area (small industrial establishments, etc.) and utilize heat recovery to meet the additional energy needs of the same area. The plant has a high system fuel efficiency, but its economics are favorable only in areas of low-fuel costs. Economic analysis of a typical 450-KW conventional total energy plant showed an output cost of 15 mills per KWH, assuming a future gas cost of $0.80 per million BTU, 30-percent electrical efficiency and 45-percent waste heat recovery. This generating cost compares with a projected cost of 5 to 6 mills per KWH for conventional coal- and nuclear-fired 1,000 MW plants. Total energy plants are not expected to have a significant impact on electrical power generation during the period to 1985.

Magnetohydrodynamics

Magnetohydrodynamics (MHD) involves the generation of electricity from a moving stream of hot ionized gas, rather than from a moving mechanical dynamo. MHD alone has quite low efficiency and even in projected advanced designs could be attractive only for peaking in competition with stand alone gas turbine generators. Long-range, coal-fired combined-cycle MHD-steam plant could be the lowest cost electric generating system, operating with an overall efficiency as high as 60 percent. Considering the difficulty of the technological problems involved, the level of current research and inherent time lag from research to commercial application, the MHD concept is unlikely to have an effect on the total U.S. energy requirements during the period to 1985.

Thermionic Devices

Thermionic conversion of heat directly to electricity depends upon the emission of electrons from metal surfaces at very high temperatures. The electrons are collected on another closely spaced metal surface at lower temperature. The resulting output voltage of a single unit is 0.7 to 1.0 volts DC. Thermionic devices may be used with either nuclear or fossil-fueled generating plants for waste heat recovery. Large-scale application of the concept does not appear practical with present technology. Advanced thermionic technology applied as a topping system could increase the efficiency of a fossil-fueled plant from 5 to 10 percent and a nuclear generating plant as much as 15 percent. Due to the severe heat conditions that thermionic plants must withstand and the resultant materials problems, practical applications of this concept are not expected before 1985 and will have no detectable effect on primary electrical generation until 1990 or later.

ALTERNATIVE ENERGY FORMS

Methanol or Hydrogen From Coal

As an alternative to the manufacture of methane rich gas from coal as a substitute for natural gas, it is possible to manufacture methanol (methyl alcohol) or hydrogen or the two usable energy forms as co-products. Cost of coal-derived methanol appears to be in the range of $1.50 to $2.00 per million BTU's, based on the use of modern technology. These costs at the refinery gate will be competitive, strictly on a heat basis, with gasoline at crude oil costs of $6 to $7 per barrel if coal is available at $0.30 per million BTU's. Hydrogen and methanol costs are nearly the same per BTU by existing technology and are about 30 percent more than manufactured methane.

A technology for pipeline transportation of methanol or hydrogen does not presently exist. Projected costs for moving methanol by pipeline is about twice the cost per BTU than that of petroleum liquids but a third less than present costs for pipeline transportation of natural gas or unit train movement of bituminous coal. Because of low-heat value, hydrogen pipeline movement is expected to be three times that of methanol per BTU.

There are many technical problems in the handling and use of both methanol and hydrogen that will probably delay widespread use past 1985, even though the cost per BTU may be attractive at the refinery gate.

Hydrogen by Water Electrolysis

Electrolytic hydrogen cannot be made at costs comparable to that of synthetic fuels from coal unless low cost electric power is available. Based on projected bus bar rates of 9 to 11 mills per KWH for the 1975-1990 period, the cost to large industrial customers would not be less than 10 to 12 mills per KWH. With these power costs, electrolytic hydrogen would be clearly uneconomic as a fuel, since the cost of converted energy itself would be $4 to $5 per million BTU's. Electrolytic hydrogen will not be competitive with fuels made from coal before 1985. The future will depend on breakthroughs which would substantially reduce the cost of electric power. Such cost reductions are unlikely in the case of the breeder reactor.

Part Two

Energy Resources

Chapter Two

HYDROELECTRIC ENERGY

SUMMARY

Most of the usable sites for significant development of hydroelectric energy in the United States have already been utilized. Some growth will occur from 1971 through 1985 but will probably average only about 1.6 percent annually. Thus, hydroelectric energy will not maintain its share of electric power generation in this period.

Except for a few large new sites ranging from 500 to 2,500 megawatt (MW) capacity, the planned developments for 1971 through 1985 will include mostly small sites of less than 200-MW capacity. If the planned additions occur during the 15-year period, 316 billion KWH will be generated by hydroelectric means in 1985, compared with 249 billion in 1970. It is estimated that hydroelectric power will then contribute about 7 percent of the electric energy, compared with 16 percent in 1971.

Most of the expansion of hydroelectric power will occur the western areas of the United--States about 84 percent of it in PAD District IV and V (see Tables 4 and 5). An increase of only 10 billion KWH can be expected to be contributed by hydroelectric PAD Districts I, II and III. This amount of energy is approximately equivalent to 2,000 MW capacity of either fossil or nuclear plants. Thus, the available hydroelectric energy will barely affect requirements for coal, oil, gas and nuclear power east of the Mississippi.

An important trend has been occurring in recent years toward the design of hydroelectric plants for peak load operation. Increased this way, capacity can be built into existing sites and energy can be supplied in larger blocks, albeit over a shorter period of time. Of course, the total amount of energy does not significantly change. As evidence of this trend, a good many

TABLE 4

CONVENTIONAL HYDROELECTRIC POWER GENERATION BY PAD DISTRICT
(Billions of KWH)

	PAD Districts					
	I	II	III	IV	V	Total
1970	44.2	30.1	10.8	19.0	144.9	249
1975	46.0	30.1	12.5	25.0	157.4	271
1980	48.5	29.3	15.0	31.3	171.9	296
1985	50.0	30.0	15.5	38.0	182.5	316

TABLE 5

ENERGY FROM HYDROELECTRIC SOURCES BY PAD DISTRICT
(Trillion BTU's)

	PAD Districts					
	I	II	III	IV	V	Total
1970	475	324	116	204	1,558	2,677
1975	482	315	131	262	1,650	2,840
1980	497	300	154	321	1,761	3,033
1985	494	296	153	375	1,800	3,118

future hydroelectric plants will operate at annual average capacity factors of 20 to 25 percent, and average operating factors for newly installed capacity in the 1971 through 1985 period will be about 33 percent. This contrasts with the average operating factor of about 55 percent for the United States in 1970. There is also a trend toward rating the capacity of new, undeveloped sites at a higher level than was formerly the custom. Undeveloped capacity, therefore, does not relate directly to undeveloped or available energy.

If planned expansions occur, about 60 percent of the potential hydroelectric energy in the United States will be harnessed by 1985. Necessarily, the undeveloped potential will be mostly widely scattered small sites in the 50 to 150 MW range that may never be developed for economic reasons. Other factors may limit the development of some new sites. Some laws have been passed and more proposals made at the federal level to preserve rivers in their natural wild state. In addition, the states are removing sites from the inventory of the total potential by additional legislative action.

A developing trend in the United States is the use of pumped-storage hydroelectric power. Pumped storage is not a *primary* energy source and should not be counted as such. However, about 40 billion KWH are expected to be generated with pumped storage by 1985. Pumped storage is most complementary to nuclear energy and is expected to be mostly confined to nuclear plants. If pumped storage is used with coal-fired plants, the thermal efficiency of the overall generating complex is lowered by a slight amount. Were it assumed, however, that mine-mouth coal plants would be used for 25 percent of the pumped storage in 1985, only an additional 2 million tons of coal would be required for that year, hardly a significant amount.

UNDEVELOPED HYDROELECTRIC POWER

The total hydroelectric energy potential of the United States (exclusive of Alaska) as of January 1, 1971, is estimated to be about 530 billion KWH annually. Of this total, 249 billion KWH were being generated annually through facilities already installed. The remaining 281 billion KWH represent the total undeveloped hydroelectric energy in the United States. However, according to the Federal Power Commission (FPC), economics and other factors may prevent the development of much of this potential. There are a limited number of remaining sites suitable for economic development.

Some idea of the problems can be realized from the inventory of undeveloped hydroelectric sites compiled by the FPC in their 1968 report. Exclusive of Alaska, the total undeveloped capacity in the United States was 98,000 MW at 1,457 separate sites. The average capacity of a single site would be about 67 MW. However, some sites could tolerate a significantly higher capacity. Examples of the latter would be the Middle Snake in Idaho (2,500 MW); St. John, Maine (830 MW); and Devils Jump, Kentucky (500 MW). These larger sites are being considered for development during the 1980 through 1990 period.

New project additions planned through 1990 for various Census Divisions are shown in Table 6. This summary does not include capacity additions to existing facilities or sites having a size less than 100 MW. As shown, the average capacity of the 41 new sites would be 272 MW. This total includes the large Middle Snake facility at 2,500 MW, the Ben Franklin site at 848 MW and the St. John site in Maine at 830 MW. If these plants are subtracted from the total, the remaining 38 projects would have an average capacity of 183 MW. These figures illustrate the fundamental problem of undeveloped hydroelectric capacity in the United States. Very few large undeveloped sites remain, and planned development in the 1980 through 1990 period will include mostly small sites of less than 200 MW.

TABLE 6

PLANNED NEW HYDROELECTRIC FACILITIES IN 1978-1990

Census Division	New Projects	Total Capacity (MW)	Average Size (MW)
New England			
(St. John, Maine)	1	830	830
Middle Atlantic	1	180	180
South Atlantic	10	2,168	217
East South Central	6	1,124	187
West South Central	4	480	120
Mountain	14	5,027	359
Pacific	5	1,333	267
Total	**41**	**11,142**	**272**

Source: Federal Power Commission, Bureau of Power, April 1971.

If the planned additions to hydroelectric occur through 1990, 335 billion KWH will be generated annually through water power. This will then represent about 65 percent of the total potential of hydroelectric energy in the United States (exclusive of Alaska). The developed capacity of hydroelectric will be 81,720 MW and will represent about 57 percent of the potential capacity. The undeveloped potential of 64,000 MW and the untapped energy of 185 billion KWH will necessarily be widely scattered hydropower that may not be developed for economic reasons. This is realizable as the planned additional installations for 1980 to 1990 will be in the 100 to 200-MW range. The majority of any remaining hydroelectric energy after 1990 will be at small sites on the order of 40 to 150 MW.

THE TREND TO PEAKING HYDROELECTRIC PLANTS

An important trend in hydroelectric facilities has been developing in recent years--the design of hydroelectric plants with increasing emphasis on peak-load operation. With the current construction of large fossil-fuel units and nuclear plants for base-load operation, there is an increasing need for plants designed specifically for peaking. Hydroelectric plants have no thermal inertia problems and are capable of following load changes extremely rapidly. New hydroelectric plants are constructed with larger capacity generators than would have been used a number of years ago. Also, existing plant capacities are being expanded to provide a peaking capability for the system.

The total amount of peaking capacity which can be installed at a hydroelectric site depends on a number of factors. The rate of change of the reservoir and tailwater levels must usually be carefully controlled to protect various water-oriented interests. In the Pacific-Northwest, many of the hydro-projects are purposely designed and constructed with provisions for additional capacity to be added later. Examples of the trend for provision of peaking rather than base-load power are the Libby facility on the Kootenai River in northern Idaho and the Dworshak facility on the Snake River in central Idaho. The ultimate annual capacity factor of these power plants will be about 20 percent.

Another example of this trend exists at the Grand Coulee-Chief Joseph complex on the Columbia River. The installation of six authorized 600-MW units at Grand Coulee will increase the capacity to 5,967 MW. Consideration is being given for six more 600-MW units at Grand Coulee increasing the total capacity to 9,470 MW. The average annual capacity factor at Grand Coulee would then be about 25 percent.

Downriver at Chief Joseph, capacity is now about 1,024 MW. Plans are under way to install 11 more units during the 1975 through 1977 period, increasing the total capacity to 2,069 MW. The annual average capacity factor at Chief Joseph would then be about 50 percent. However, Chief Joseph is ideally suited for the installation of additional peaking units. Studies are under way which consider raising the Chief Joseph pool so that it can accommodate the peaking releases from Grand Coulee as well as provide additional generating units.

New reservoirs or additions to reservoir capacity are often required downstream from a peaking hydroelectric project to smooth out the release of peaking water and maintain safe and acceptable conditions downstream. The Libby re-regulation dam on the Kootenai is an example of this requirement.

All hydroelectric projects cannot be converted to peaking facilities with 20- to 25-percent annual operating factors, however. In the interest of navigation and other water uses, the ultimate annual capacity factor of some waterways cannot practically be less than about 40 percent. The maintenance of acceptable conditions for navigation and recreational use would preclude capacity factors below about 40 percent for sections of the Columbia and Snake River, for example.

In the recent past, annual operating factors for hydroelectric facilities were high. Table 7 shows data which were calculated from the 1971 FPC report and are the operating experience for 1970. Washington state, where about 30 percent of the energy was generated, had an operating factor of about 68 percent. Other western states were in the 62- to 66- percent range. The Tennessee Valley Authority (TVA) dams, as evidenced by the data for Alabama and Tennessee, had operating factors from 35 to 46 percent. Thus, the

TABLE 7

GENERATION AND OPERATING FACTORS FOR SELECTED STATES
(1970 Operating Data)

State	Generation (Billion KWH)	Capacity (MW)	Annual Capacity Factor (%)
New York	25.09	3,729	76.7
Washington	69.38	11,599	68.3
Montana	8.74	1,512	66.0
Idaho	7.08	1,250	64.7
Oregon	29.84	5,369	63.4
California	37.90	6,954	62.1
South Dakota	6.54	1,384	54.0
Tennessee	8.07	2,022	45.5
Arizona	6.14	1,929	36.3
Alabama	7.61	2,508	34.7
North Carolina	4.36	1,835	27.2
Georgia	2.46	1,056	26.6
Remaining States	35.8	10,250	39.9
Total	**248.97**	**51,403**	**55.3**

Source: Federal Power Commission, Bureau of Power, April 1971.

TVA system dams had already evolved to an intermediate load or peaking role in 1967.

The average operating factor for the United States was 55.6 percent in 1967. The 1970 FPC National Power Survey shows that the average was still 55.3 percent in 1970. However, as shown in Table 8, the operating factor will decrease steadily as new capacity is added in the period from 1970 to 1990. By 1990, the operating factor will be down to 46.8 percent. It can be seen that the incremental additions to capacity in the 20-year period will have an operating factor of about 32 percent.

TABLE 8

TRENDS IN OPERATING FACTORS

	(Billion KWH)	Capacity (Gigawatt)*	Annual Operating Factor (Percent)
1970	249	51.4	55.3
1980	296	68.0	49.7
1990	335	81.7	46.8
Incremental Addition; 1970-1980	47	16.6	32.3
Incremental Addition; 1980-1990	39	13.7	32.5

* Gigawatt = 1 billion watts.

ECONOMICS OF HYDROELECTRIC POWER

Construction costs for hydroelectric projects are extremely variable. Costs depend on the size and location of the dam; the head and amount of water backed up; the cost of land; and the cost of relocating facilities such as homes, roads and railroads. The Allegheny Reservoir near Kinzua, Pennsylavania, is an example. While the dam and power facilities cost about $15 million, relocation of roads and railroads and other property adjustments added another $99 million to the cost. The Pleasant Valley-Mountain Sheep project on the Snake River near the Idaho-Oregon border has been proposed for a number of years. The facility is expected to cost $275 million for 1,640 MW of power. The 1971 FPC Report indicates that the annual capacity factor of this site would be about 20 percent. Thus, the cost of this peaking power would be on the order of 10 to 12 mills per KWH. There are large variations in costs for hydroelectric facilities but, on the average, costs per installed kilowatt are higher than for thermal plants. The operating costs for hydroelectric facilities, however, are very low because there are no fuel costs.

Reservoirs of water used in connection with hydroelectric power have many uses including flood control, conservation, irrigation, flow control and recreation. Future developments might well encompass multiple uses whereby the power generation aspects will continue to bear only a part of the capital burden.

A recent survey of various regions of the country indicated that hydroelectric power costs were 2.4 mills per KWH in the Pacific Northwest and 8.4 mills in the Southwest. In the Midwest and Southeast the cost ranges from 4.34 mills to 5.62 mills. The Northwest rates are low because they represent high load factors made possible by favorable hydroelectric sites, while the Southwest power is peaking power.

The trend to peaking power for hydroelectric sites should increase the cost of power, however, as the capital items which are allocated to power costs will be used a smaller fraction of the time. The necessity for additional generators would also add to the capital burden. At Grand Coulee, a third power plant is now being constructed to accommodate the additional 12 (600 MW) generators. A reasonable estimate is that the cost of peaking power in the Northwest should be at least double the current cost or about 5 mills per KWH.

PUMPED STORAGE HYDROELECTRIC ECONOMICS

A developing trend in electric generation is the use of reservoirs to store water. Base-load fossil fuel plants and nuclear plants can be used to store water for peaking purposes. It makes economic sense to operate around the clock and to pump water at night and on weekends with base-load plants. The stored water can then be used as conventional hydroelectric power when electrical demand peaks during daylight hours on weekdays. The reversible pump-turbine-generator permits water to be pumped uphill and also provides generation of electric power with the same unit when the water falls. Because of energy losses in conversion and friction, 3 KWH of energy must be used to place 2 KWH of water in an upper reservoir.

Strictly speaking, pumped storage facilities do not constitute an energy source. However, pumped storage is sometimes included in discussions of hydroelectric energy. A recent FPC forecast of rapid expansion in pumped storage facilities in the United States is illustrated in Table 9.

The availability of pumped storage sites depends mostly on topography. A high head must exist between two reservoirs in the same area. Most of the planned pumped storage facilities are in the Appalachian Mountain area of the Carolinas, Virginia, West Virginia and Kentucky. Additional sites are planned in California and the Ozarks. The FPC has recently indicated that many potential pumped storage sites exist in the Northwest with capacities up to 10,000 MW.

When a fossil fuel plant is used to pump water for pumped storage, a decrease in efficiency occurs. For example, if the heat rate of the plant is 9,500 BTU's per KWH in normal operation, the

TABLE 9

PUMPED STORAGE HYDROELECTRIC IN THE UNITED STATES

	Total Capacity (MW)	Pumping Energy Required (Billion KWH)*	Net Generation (Billion KWH)†
1970	3,600	6	4
1980	27,000	36	24
1990	71,000	94	63

* Reported as 8, 38 and 94 in the Initial Appraisal.

† Reported as 5, 25 and 63 in the Initial Appraisal.

TABLE 10

PUMPING STORAGE PLANTS COST DATA

Cost of Plant	No. of Cases	Total Cost (Thousand Dollars)	Average Cost (Dollars)
1. Land and land rights	7*	10,742	1,535,000
	6†	10,651	1,775,000
2. Reservoirs, dams and waterways	10*	160,605	16,061,000
	8†	158,661	19,832,000
3. Structures and improvements	11*	57,735	5,249,000
	8†	51,119	6,395,000
4. Equipment costs	11*	93,343	8,940,000
	8†	35,040	10,636,000
5. Roads, railroads and bridges	10*	2,070	307,000
	8†	2,863	358,000
Cost per KW installed capacity (nameplate)	11*	2,405	219†
	8†	1,176	147
Cost pumping energy	4†	–	3.445 mills/KW
Annual operating factor (net generation divided by 8,760 hours times gen. capacity)	4*	–	– 17%
	2†		

* Average of total data, including plants where pumped storage is combined with conventional facilities.

† Based on data for single purpose pumped storage plants.

Source: Federal Power Commission, 13th Annual Supplement, 1969.

heat rate would increase to about 11,000 if the plant were used to pump water for 30 percent of the time. Thus, the advent of pumped storage for fossil fuel plants would increase the amount of primary energy required for electrical generation. If pumped storage is accomplished with nuclear plants, it has a relatively small effect on the overall uranium requirements. It is for this reason that pumped storage is a more logical complement of nuclear plants.

Cost data on pumped storage plants is meager. Table 10 represents data from the FPC's 13th Annual Supplement issued in 1967. It shows an average cost per KW installed (nameplate) of $219 where pumped storage was combined with conventional facilities and $147 for single purpose storage plants. Cost of pumping energy, based on only four plants, was 3.445 mills per KWH.

Energy for pumped storage should only represent about 3 percent of the total electrical generation by 1990. Accordingly, it should have a minor effect on total energy required.

STATISTICS OF HYDROELECTRIC ENERGY

A detailed breakdown of developed and undeveloped hydroelectric power by state and Census Division is given in Table 11. These statistics have been regrouped into Petroleum Administration Defense (PAD) Districts in Table 12. This shows that the major portion of undeveloped hydroelectric power is in PAD Districts IV and V.

A breakdown of the installed capacity, projects under construction and proposed new additions through 1990 are summarized in Table 13. A total of about 52 gigawatts (GW) out of the total 82 GW in the United States in 1990 will be in PAD Districts IV and V.

The maximum hydroelectric potential in the United States for the various PAD Districts is detailed in Table 14. The KWH factor has been converted to total BTU potential using the conversion factor of 9,880 BTU's per KWH. This is the average heat rate that the NPC predicts for 1985. In additon, the hydroelectric potential of each PAD District is converted to equivalent barrels of oil. The estimated KWH generated by PAD Districts through 1990 is shown in Table 15.

A breakdown of the equivalent BTU's displaced in the PAD Districts through 1990 is shown in Table 16 and the oil equivalent in Table 17. This is based on the planned additions in the 1970 through 1990 period and the recent FPC forecast of total KWH for the United States. The FPC had forecast that 335 billion KWH would be generated by hydroelectric by 1990. The assumption made in Tables 15 and 16 is that 316 billion KWH will be available by 1985. This would of course depend on the rate of completion of scheduled new projects.

TABLE 11

HYDROELECTRIC POWER RESOURCES OF THE UNITED STATES—CONVENTIONAL HYDRO PLANTS

	Developed		Undeveloped		Total Potential	
	Installed Capacity (KW)	Av. Annual Generation (GWH)*	Capacity (KW)	Av. Annual Generation (GWH)	Capacity (KW)	Av. Annual Generation (GWH)
New England						
Maine	509,470	2,528	1,714,074	4,289	2,223,544	6,817
New Hampshire	428,942	1,306	802,100	983	1,231,042	3,289
Vermont	199,742	833	337,701	701	537,443	1,534
Massachusetts	219,001	869	266,728	742	485,729	1,611
Rhode Island	2,860	8	–	–	2,860	8
Connecticut	131,115	390	183,200	552	314,315	942
Total	**1,491,130**	**5,934**	**3,303,803**	**7,267**	**4,794,933**	**13,201**
Middle Atlantic						
New York	3,809,050	23,777	1,292,175	3,293	5,101,225	27,070
New Jersey	8,294	48	241,000	1,001	249,294	1,049
Pennsylvania	429,520	1,816	2,980,630	7,057	3,410,150	8,873
Total	**4,246,864**	**25,641**	**4,513,805**	**11,351**	**8,760,669**	**36,992**
East North Central						
Ohio	2,399	12	249,200	1,206	251,599	1,218
Indiana	109,987	590	315,000	1,085	424,987	1,675
Illinois	42,931	196	206,200	1,101	249,131	1,297
Michigan	394,538	1,734	272,200	782	666,738	2,516
Wisconsin	418,668	1,922	213,200	949	631,868	2,871
Total	**968,523**	**4,454**	**1,255,800**	**5,123**	**2,224,323**	**9,577**
West North Central						
Minnesota	170,295	906	157,210	723	327,505	1,629
Iowa	135,675	811	345,200	1,632	480,875	2,443
Missouri	392,600	1,009	2,024,600	9,269	2,417,200	10,278
North Dakota	400,000	1,886	195,000	840	595,000	2,726
South Dakota	1,392,196	4,437	303,000	884	1,695,196	5,321
Nebraska	238,236	1,177	1,035,710	3,388	1,273,946	4,565
Kansas	5,150	13	303,000	1,460	308,150	1,473
Total	**2,734,152**	**10,239**	**4,363,720**	**18,196**	**7,097,872**	**28,435**
South Atlantic						
Maryland	494,280	1,750	163,000	497	657,280	2,247
District of Columbia	3,000	5	–	–	3,000	5
Virginia	735,981	1,144	1,276,231	2,962	2,012,212	4,106
West Virginia	208,010	1,015	1,994,040	6,793	2,202,050	7,808
North Carolina	1,765,525	5,196	919,350	2,000	2,684,875	7,196
South Carolina	1,034,153	2,788	1,834,530	2,356	2,868,683	5,144
Georgia	1,069,136	3,259	3,197,766	4,646	4,266,902	7,905
Florida	38,968	240	83,500	69	122,468	309
Delaware	–	–	–	–	–	–
Total	**5,349,043**	**15,397**	**9,468,417**	**19,323**	**14,817,470**	**34,720**

TABLE 11 (Cont'd.)

HYDROELECTRIC POWER RESOURCES OF THE UNITED STATES—CONVENTIONAL HYDRO PLANTS

	Developed		Undeveloped		Total Potential	
	Installed Capacity (KW)	Av. Annual Generation (GWH)*	Capacity (KW)	Av. Annual Generation (GWH)	Capacity (KW)	Av. Annual Generation (GWH)
East South Central						
Kentucky	670,617	3,053	1,484,800	3,300	2,155,417	6,353
Tennessee	1,893,500	8,044	688,100	2,189	2,581,600	10,233
Alabama	2,267,485	8,223	1,629,520	2,939	3,897,005	11,162
Mississippi	–	–	140,300	381	140,300	381
Total	**4,831,602**	**19,320**	**3,942,720**	**8,809**	**8,774,322**	**28,129**
West South Central						
Arkansas	900,340	2,285	915,100	1,903	1,815,440	4,188
Louisiana	–	–	76,000	461	76,000	461
Oklahoma	363,400	1,142	913,600	2,043	1,277,000	3,185
Texas	434,180	1,278	1,160,035	1,837	1,594,215	3,115
Total	**1,697,920**	**4,705**	**3,064,735**	**6,244**	**4,762,665**	**10,949**
Mountain						
Montana	1,511,848	8,219	6,269,220	21,876	7,781,068	30,095
Idaho	1,250,839	7,588	12,391,631	41,100	13,642,470	48,688
Wyoming	212,140	940	1,286,290	6,117	1,498,430	7,057
Colorado	314,270	1,279	1,784,600	7,123	2,098,870	8,402
New Mexico	24,300	96	154,200	595	178,500	691
Arizona	1,879,190	8,102	3,676,000	15,749	5,555,190	23,851
Utah	207,915	957	1,320,050	4,917	1,527,965	5,874
Nevada	682,120	2,126	8,800	35	690,920	2,161
Total	**6,082,622**	**29,307**	**26,890,791**	**97,512**	**32,973,413**	**126,819**
Pacific						
Washington	9,549,389	62,516	23,498,864	74,075	33,048,253	136,591
Oregon	3,449,205	20,847	5,686,190	21,141	9,135,395	41,988
California	5,323,697	24,506	11,908,750	35,367	17,232,447	59,873
Total	**18,322,291**	**107,569**	**41,093,804**	**130,583**	**59,416,095**	**238,452**
Alaska	83,636	338	32,511,100	172,496	32,594,736	172,834
Hawaii	18,698	107	35,000	229	53,698	336
United States Total	**45,826,491**	**223,311**	**130,443,695**	**477,133**	**176,270,186**	**700,144**

* GWH = 1,000,000 KWH.

Source: Federal Power Commission, "Hydroelectric Power Resources of the United States, Developed and Undeveloped, January 1, 1968," Report P-36.

TABLE 12

HYDROELECTRIC POWER RESOURCES OF THE UNITED STATES--CONVENTIONAL HYDRO PLANTS
(January 1, 1968)

	Developed		Undeveloped		Total Potential		
	Installed Capacity (KW)	Number of Sites	Capacity (KW)	Number of Sites	Capacity (KW)	Number of Sites	Percent Capacity Developed
PAD District I							
New England							
Maine	509,470	81	1,714,074	37	2,223,544	118	22.9
New Hampshire	428,942	42	802,100	21	1,231,042	63	34.8
Vermont	199,742	56	337,701	17	537,443	73	37.2
Massachusetts	219,001	65	266,728	11	485,729	76	45.1
Rhode Island	2,860	4	–	0	2,860	4	100.0
Connecticut	131,115	21	183,200	11	314,315	32	41.7
Total	1,491,130	269	3,303,803	97	4,794,933	366	31.1
Middle Atlantic							
New York	3,809,050	165	1,292,175	51	5,101,225	216	74.7
New Jersey	8,294	7	241,000	6	249,294	13	3.3
Pennsylvania	429,520	11	2,980,630	37	3,410,150	48	12.6
Total	4,246,864	183	4,513,805	94	8,760,669	277	48.5
South Atlantic							
Maryland	494,280	3	163,000	5	657,280	8	75.2
District of Columbia	3,000	1	–	–	3,000	1	100.0
Virginia	735,981	33	1,276,231	31	2,012,212	64	36.6
West Virginia	208,010	10	1,994,040	27	2,202,050	37	9.4
North Carolina	1,765,525	63	919,350	30	2,684,875	93	65.8
South Carolina	1,034,153	41	1,834,530	21	2,868,683	62	36.0
Georgia	1,069,136	36	3,197,766	47	4,266,902	83	25.3
Florida	38,968	3	83,500	1	122,468	4	31.8
Delaware	–	–	–	–	–	–	–
Total	5,349,043	190	9,468,417	162	14,817,470	352	36.1
PAD District I Total	11,087,037	642	17,286,025	353	28,373,072	995	39.1
PAD District II							
East North Central							
Ohio	2,399	2	249,200	12	251,599	14	1.0
Indiana	109,987	8	315,000	8	424,987	16	25.9
Illinois	42,931	11	206,200	13	249,131	24	17.2
Michigan	394,538	91	272,200	28	666,738	119	59.2
Wisconsin	418,668	120	213,200	17	631,868	137	66.3
Total	968,523	232	1,255,800	78	2,224,323	310	43.5
West North Central							
Minnesota	170,295	34	157,210	16	327,505	50	52.0
Iowa	135,675	12	345,200	7	480,875	19	29.2
Missouri	392,600	5	2,024,600	20	2,417,200	25	16.2
North Dakota	400,000	1	195,000	3	595,000	4	67.2
South Dakota	1,392,196	9	303,000	5	1,695,196	14	82.1
Nebraska	238,236	22	1,035,710	26	1,273,946	48	18.7
Kansas	5,150	3	303,000	8	308,150	11	1.7
Total	2,734,152	86	4,363,720	85	7,097,872	171	38.5
East South Central							
Kentucky	670,617	6	1,484,800	22	2,155,417	28	31.1
Tennessee	1,893,500	25	688,100	12	2,581,600	37	73.3
Total	2,564,117	31	2,172,900	34	4,737,017	65	54.1
West South Central							
Oklahoma	363,400	5	913,600	17	1,277,000	22	28.5
PAD District II Total	6,630,192	354	8,706,020	214	15,336,212	568	43.2

TABLE 12(Cont'd.)

HYDROELECTRIC POWER RESOURCES OF THE UNITED STATES–CONVENTIONAL HYDRO PLANTS
(January 1, 1968)

	Developed		Undeveloped		Total Potential		
	Installed Capacity (KW)	Number of Sites	Capacity (KW)	Number of Sites	Capacity (KW)	Number of Sites	Percent Capacity Developed
PAD District III							
West South Central							
Arkansas	900,340	11	915,100	17	1,815,440	28	49.6
Louisiana	–	–	76,000	5	76,000	5	0.0
Texas	434,180	20	1,160,035	40	1,594,215	60	27.2
Total	**1,334,520**	**31**	**2,151,135**	**62**	**3,385,655**	**93**	**38.3**
East South Central							
Alabama	2,267,485	17	1,629,520	19	3,897,005	36	58.2
Mississippi	–	–	140,300	8	140,300	8	0.0
Total	**2,267,485**	**17**	**1,769,820**	**27**	**4,037,305**	**44**	**56.2**
Mountain							
New Mexico	24,300	1	154,200	10	178,500	11	13.6
PAD District III Total	**3,626,305**	**49**	**4,075,155**	**99**	**7,701,460**	**148**	**47.1**
PAD District IV							
Mountain							
Montana	1,511,848	25	6,269,220	58	7,781,068	83	19.4
Idaho	1,250,839	43	12,391,631	140	13,642,470	183	9.2
Wyoming	212,140	16	1,286,290	48	1,498,430	64	14.2
Colorado	314,270	27	1,784,600	67	2,098,870	94	15.0
Utah	207,915	59	1,320,050	23	1,527,965	82	13.6
Total	**3,497,012**	**170**	**23,051,791**	**336**	**26,548,803**	**506**	**13.2**
PAD District IV Total	**3,497,012**	**170**	**23,051,791**	**336**	**26,548,803**	**506**	**13.2**
PAD District V							
Pacific							
Washington	9,549,389	57	23,498,864	185	33,048,253	242	28.9
Oregon	3,449,205	61	5,686,190	126	9,135,395	187	37.8
California	5,323,697	161	11,908,750	130	17,232,447	291	30.9
Total	**18,322,291**	**279**	**41,093,804**	**441**	**59,416,095**	**720**	**30.8**
Mountain							
Arizona	1,879,190	11	3,676,000	11	5,555,190	22	33.8
Nevada	682,120	9	8,800	1	690,920	10	98.7
Total	**2,561,310**	**20**	**3,684,800**	**12**	**6,246,110**	**32**	**41.0**
Total Contiguous U.S.	**20,883,601**	**299**	**44,778,604**	**463**	**65,662,205**	**752**	**31.8**
Alaska	83,636	29	32,511,100	84	32,594,736	113	0.3
Hawaii	18,698	19	35,000	2	53,698	21	34.8
PAD District V Total Contiguous U.S. & Alaska	**20,967,327**	**328**	**77,289,704**	**547**	**98,256,941**	**865**	**21.3**
Total U.S. (Excluding Alaska & Hawaii)	**45,724,157**	**1,514**	**97,897,595**	**1,455**	**143,621,752**	**2,969**	**31.8**

Source: Federal Power Commission, "Hydroelectric Power Resources of the United States, Developed and Undeveloped, January 1, 1968," Report P-36.

TABLE 13

PLANNED HYDROELECTRIC CAPACITY BY PAD DISTRICTS
(Gigawatts)

	PAD Districts					
	I	II	III	IV	V	Total
Existing—1970	10.58	6.76	3.96	3.57	26.53	51.40
Total—Proposed to 1980	13.18	7.99	4.54	6.63	35.71	68.04
Total—Proposed to 1990	15.60	8.43	5.30	11.20	41.18	81.72

Source: Federal Power Commission 1971 Report.

TABLE 14

MAXIMUM HYDROELECTRIC POTENTIAL IN UNITED STATES

	(Million KWH)	Max. BTU Potential 1985 (Trillions)	Maximum Potential, Equivalent (BBL Oil/Day)
PAD District I	84,913	838	395,800
PAD District II	57,783	570	269,200
PAD District III	19,998	197	93,060
PAD District IV	100,116	988	466,700
PAD District V (Ex. Alaska)	264,463	2,609	1,232,000
PAD Districts I-V (Ex. Alaska)	527,273	5,202	2,456,760
Alaska	172,834	1,705	805,400
Total	**700,107**	**6,907**	**3,262,160**

TABLE 15

GENERATION OF KWH, CONVENTIONAL HYDROELECTRIC BY PAD DISTRICTS
(Billions)

	PAD Districts					
	I	II	III	IV	V	Total
1970	44.2	30.1	10.8	19.0	144.9	249
1975*	46.0	30.1	12.5	25.0	157.4	271
1980	48.5	29.3	15.0	31.3	171.9	296
1985*	50.0	30.0	15.5	38.0	182.5	316
1990	52.3	30.8	16.1	45.0	190.8	335

* Data interpolated from 1970, 1980, 1990 Federal Power Commission data.

TABLE 16

ENERGY FROM HYDROELECTRIC BY PAD DISTRICTS*
(Trillion BTU's)

	PAD Districts					
	I	II	III	IV	V	Total
1970	475	324	116	204	1,558	2,677
1975	482	315	131	262	1,650	2,840
1980	497	300	154	321	1,761	3,033
1985	494	296	153	375	1,800	3,118
1990	496	292	153	427	1,810	3,178

* Calculated from Table 15 using the following heat rates (BTU/KWH):

1970–10,753
1975–10,480
1980–10,246
1985– 9,866
1990– 9,486

TABLE 17

EQUIVALENCE OF HYDROELECTRIC POWER IN OIL REPLACED BY PAD DISTRICTS

	PAD Districts					
	I	II	III	IV	V	Total
Generation for 1970, Million KWH	44,216	30,056	10,820	18,965	144,909	248,966
Equivalent B/D of Oil, 1970*	224,500	152,600	54,960	96,330	736,500	1,264,890
Expected Generation for 1985, Million KWH	50,000	30,000	15,500	38,000	182,500	316,000
Equivalent B/D of Oil, 1985†	233,000	139,800	72,240	177,100	850,500	1,472,640

* At heat rate of 10,753 BTU/KWH.

† At heat rate of 9,866 BTU/KWH.

The total BTU equivalents forecast in Table 16 are lower than forecasts made by other groups recently. It is believed, however, that many forecasters of hydroelectric energy have failed to take into account the fact that much of the additional capacity does not add to the total energy. The trend to the concept of peaking power in hydroelectric means that the capacity will go up significantly but the energy generated will not increase so significantly.

The equivalent energy in BTU decreases in PAD Districts I, II and III in some 5-year intervals, but this is due to the fact that the heat rate decreases from 10,753 BTU per KWH in 1970 to 9,866 in 1985.

IMPORTS OF HYDROELECTRIC POWER FROM CANADA

The FPC has concluded that little hydroelectric power will be available from Canada on a long-term basis. This is due to the rapid rate of load growth in Canada. Some selected sites where interim power could be available in the 1974 through 1985 period include --

- Churchill Falls, Labrador
- Nelson River, Manitoba
- Peace and Upper Columbia, B.C.
- Rupert River, James Bay, Quebec.

Power interties would allow that some power, ranging from 300 to 2,000 MW, would be available at the several locations. The Rupert River development in Quebec, which is now undergoing engineering analysis, has promise of providing electric power for the Northeast U.S. region on an interim basis starting in about 1978. Estimates at the time of this writing indicate that the available capacity would be no more than about 2,000 MW for an interim period starting about 1980. Canadian hydroelectric power would only provide a temporary availability of limited energy for the United States.

Chapter Three

GEOTHERMAL ENERGY

SUMMARY

The development of geothermal energy in Western United States appears promising for the 1971-1985 period. Commercial development of the Geysers Field, California, began in 1960, and a capacity of 82 MW existed in 1970. Planned expansion by one operator is expected to increase to about 600 MW by 1975. In estimating the amount of geothermal power expected to be developed through 1985, it was assumed that the recently passed federal law permitting leasing of federal lands will stimulate exploration in areas of favorable geological indications of steam. Projections were made on the planned development of the Geysers Field as well as presently sub-commercial fields in California and Nevada. Accordingly, it is estimated that 7,000 MW will exist by 1985 (Table 18), an increase by a factor of nearly 100 in 15 years.

TABLE 18

ESTIMATED GEOTHERMAL STEAM GENERATING CAPACITY FOR PAD DISTRICT V (MW)

Cost (¢/KWH)	1970	1975	1980	1985
0.525	82	1,500	4,500	7,000
0.575	–	–	4,000	7,000
0.625	–	–	2,000	5,000
Total	82	1,500	10,500	19,000

All of this capacity will be in California and Nevada and available in PAD District V. Total generating capacity in California and Nevada should grow to between 75,000 and 90,000 MW by 1985. Accordingly, in those two states geothermal steam should account for about 9 percent of the total generating capacity in 1985. Since geothermal steam will have a high load factor, it should contribute about 11 percent of the generated electrical energy.

The cost of developing geothermal production is estimated to be $0.525 per KWH at the present time (Table 19). Information for arriving at this figure was taken from experience at the Geysers Field, California. A load factor of 85 percent was used, representing a compromise between 1970 production figures and the load factors predicted for the future. Costs can be broken down to 2.66 mills for steam costs delivered to the plant, 0.45 mills for operating costs and 2.14 mills for capital costs. It was assumed that

TABLE 19

EQUIVALENT ENERGY FROM GEOTHERMAL SOURCES*
(BTU x 10^{15})

Cost (¢/KWH)	1970	1975	1980	1985
0.525	0.0066	0.117	0.343	0.514
0.575	–	–	0.305	0.514
0.625	–	–	0.153	0.367
Total	0.0066	0.117	0.801	1.395

* Based on an 85-percent operating factor.

the cost of geothermal power will be cheaper than that derived from fossil-fuel steam plants and that it will be developed faster than nuclear steam plants at roughly the same costs per KWH. All cost estimates are in 1970 dollars.

For every vapor-dominated geothermal system discovered, it has been estimated there will be 20 hot-water systems found. Since no hot-water system fields are yet in production in the United States, we have no cost data for comparison to the Geysers. Experiments with dual-fluids heat-exchanging techniques now being conducted near Reno, Nevada, give promise that lower temperature hot-water systems can be produced economically.

If heat exchangers are developed, additional prospects will be attractive for exploration. The availability of suitable heat-exchange techniques is reflected in the estimates of additional capacity. For example, the installed capacity could be estimated to be as high as 19,000 MW by 1985 (Table 18), based on such development. The increase in power cost from 5.25 mills to 6.25 mills (Table 19) for more complex equipment is speculative, however.

Most of the exploratory drilling conducted to date has been in areas of high heat gradient and near-boiling hot springs. Only a small number of such areas have been tested so far, however, although all the states of the United States lying west of the Continental Divide (encompassing California, Oregon, Washington, Idaho, Nevada, Arizona, New Mexico and parts of Montana, Wyoming and Colorado) are potentially good hunting grounds. Good surface indications of volcanic activity, high heat gradient and numerous hot springs, such as are found throughout the western part of the United States, suggest that there are many prospective sites that may eventually be capable of steam and/or hot water production. The recently enacted Federal Geothermal Leasing Act would make available millions of acres of promising land for prospecting. There has been a corresponding increased interest in obtaining leases and in conducting explorations.

In estimating the amount of geothermal energy available in 1980 and 1985, the task group has assumed that only a small portion of the potential prospects will prove to be commercially productive. Scarcity of population and lack of a market in portions of the western states will discourage exploration in areas that otherwise would be good prospects.

Present indications are that exploration will be conducted for the most part by private industry, including public utilities and oil exploration companies, as well as companies specifically organized for the exploration and development of geothermal power. The Federal Government's Bureau of Reclamation has been active in financing R&D for the Imperial Valley. If desalinization proves feasible in the Salton Sea area, power development may proceed faster than has been indicated from 1980 to 1985.

For appraising the longer-range prospect of geothermal energy, not only localized hydrothermal systems should be considered, but also the deep sedimentary basins that contain large masses of water. The prospective amount of heat in such waters of U.S. sedimentary basins is considerable, and the total amount of energy that may be recovered from such sources may well surpass the heat to be derived from combustion of the oil and gas in those basins.

Several uncertainties exist, however, with respect to current estimates about the possible size of the resources. The magnitude of the *in situ* heat reserve depends mainly on such factors as the temperature at depth, the porosity of the sedimentary section, the section thickness and the lateral extent of the permeable sediments. How much of this heat can be recovered hinges on such factors as permeability, lateral continuity, size of hydraulically connected water masses, sub-surface water pressure and the effectiveness of flashing as a means to lift the thermal waters. Knowledge of the above-mentioned factors is limited for the deep parts of the sedimentary basins. Exploration efforts in these areas will be a function of the above-mentioned uncertainties, the large resources potential and the prospective economics.

It seems possible that the uncertainties could be resolved, at least for some sedimentary basins, before 1985. If resolved favorably, then geothermal energy could attain, in the United States, a greater role in supplying electric energy and heat than is indicated in this report.

The heat stored in deep magma chambers and cratonic rocks near volcanic activity is vast but is decades away from exploitation. Technical obstacles and economics plus unknown contingencies make these potential energy resources less attractive for research and development than several other unexploited resources.

The following sections of this chapter present a history of geothermal energy use, a discussion of geothermal energy supply prospects in the United States to 1985 and the long-range potential for geothermal energy resources in the United States.

HISTORY OF GEOTHERMAL ENERGY USE

The Romans made use of natural hot waters in Italy and other countries of Central Europe. The Turks made use of them in their famous "Turkish Baths."

At Larderello, Italy, in 1777, the first commercial use of geothermal resources took place, consisting of the recovery of borax from natural steam and hot water vents. At about the same time, natural hot water was utilized in Iceland to produce salt from seawater by evaporation. In 1827, a second mineral constituent, boric acid, was recovered from the same waters at Larderello. Today, as by-products of steam, several other constituents are recovered from the natural waters in that area including sulfur, borax and other chemicals.

During the 19th century, hot springs in Georgia and Arkansas were developed into spas, as was the Geysers area and a number of other hot springs in California. Yellowstone National Park was established around the hot springs and geysers in that area.

The first power-generating station to use natural steam for electricity was established at Larderello, Italy, in 1904. There were efforts to develop electricity from geothermal resources in Japan in 1922 and at the geysers Sonoma County, California, in 1922. Neither met with success, but each contributed to today's success in generating electricity at both areas.

In New Zealand, attempts were made in 1925 to harness geothermal steam, but it was not until 1946 when the government took over the operation that significant progress was made.

In 1925, development of natural steam was started in Iceland for space heating, and by 1930 homes and industries in Reykjavik, Iceland, were being supplied with natural steam. One-fourth of the population uses geothermal sources for heat. A 15-MW plant began operation in 1966.

At the present time the United Nations is sponsoring development of geothermal resources in underdeveloped countries such as Kenya, Tanganyika, Turkey, Chile and El Salvador. Russia, Japan and Mexico are conducting their own development of geothermal resources. Japan has 31-MW producing capacity and expects to reach 100. Mexico has a 3.5-MW pilot plant on stream and a 75-MW plant under construction. The Italian Larderello Field is capable of producing 390 MW, a considerable increase from the modest beginning of 500 KW in 1904. A new field of promise has been developed at Monte Amiata.

Generating capacity at the Wairakei Geyser area in New Zealand had increased to 192 MW in 1968, with plans to add 150 MW in the next year or two.

Most of the exploration conducted in the United States to date has been concentrated in the area west of the Continental Divide where there is an above-normal geothermal gradient and numerous hot springs. Since the first exploration began, over 200 wells have been drilled in 35 areas.

Exploration activities in the United States have been carried on by both public and private organizations. The Carnegie Institute sponsored two shallow test holes in the Upper Geyser Basin and Norris Basin of Yellowstone Park and encountered high temperatures and steam at shallow depths.

During the 1920's, studies were made of Mt. Lassen, California, and Mt. Katmai, Alaska. The U.S. Geological Survey (USGS) conducted studies and drilled coreholes in the Steamboat Springs area of Nevada from 1920 to 1950.

GEOTHERMAL ENERGY SUPPLY PROSPECTS IN THE UNITED STATES TO 1985

Potential Areas of Production in the United States

The most favorable areas of geothermal production in the United States lie in the western part of the country, primarily in the states of California, Nevada, Oregon, Washington, Idaho, Utah, Arizona, Wyoming, Montana, Colorado and New Mexico. Alaska and Hawaii can also be included with this group. This is evidenced by high heat gradients and the occurrence of large numbers of warm to hot springs, fumaroles and geyser complexes whose temperatures approach the local boiling point (Table 20).

TABLE 20

NUMBER OF HOT SPRINGS, FUMAROLES, ETC., IN THE UNITED STATES

State	Number of Hot Springs, Fumaroles, Etc.
California	181
Oregon	86
Nevada	152
Idaho	196
Washington	16
New Mexico	38
Montana	40
Utah	56
Colorado	44
Wyoming	116*
Arizona	21
West Virginia	30
Virginia	20

* Including 96 in Yellowstone National Park.

Some of these localities are represented by a single spring of low flow and enthalpy while others, such as Yellowstone National Park, cover many acres. About 100 of these hot fluid surface localities are close to the boiling point.

The western part of the United States also contains much surface evidence of recent (Quaternary) volcanism. Many hot springs are associated with recent faulting. Much of it is basin and range type, in areas of recent volcanism. Other springs are located in areas where the earth's crust is believed to be thin and where convective rifting has taken place. In both cases, faults serve as the vehicle for heat flow to the surface.

In 1955, exploratory work was renewed in the Geysers area, and four producers were completed at depths of less than 1,000 feet.

In 1958, a contract was executed between the owners of the wells (Magma Power Company and Thermal Power Company) and the Pacific Gas and Electric Company (PG&E), whereby PG&E erected a plant to generate electricity at a capacity of 12,500 KW. This first plant went on production in 1960 at a capacity of 12,500 KW. A second plant was completed in 1962, bringing the total capacity to 26,500 KW. Twenty-one wells were drilled from 1961 to 1966, justifying the addition of two 27,500 KW plants, bringing the total number of plants to four.

In 1967, Union Oil Company of California leased a large block of acreage in the Geysers area and joined with Magma Power and Thermal Power companies in a joint operation, with Union as operator. At the present writing, 68 wells have been completed by the Union Oil Company-Magma-Thermal group and two more plants (55,000 KW) were completed in mid-1971. PG&E, which built and operates the plants, plans to add 100 MW per year through 1975, bringing the total power generating capability to 600 MW. The Geysers Field is expected to develop into the largest field in the world in the next few years, surpassing Larderello and Wairakei. At the present time, the field is approximately 7 miles long and from 1 mile to 2 miles wide. The average well appears capable of producing around 5,000 KW.

The second most active area in California is the Salton Sea area. Attention was first drawn to this area by the bubbling hot mud pots on the east side of the sea and about 4 miles north of the present field. Carbon dioxide (CO_2) was recognized in the discharge from these fumaroles, and in 1934 a well was completed producing CO_2 gas. Subsequent drilling proved up enough potential for a commercial dry-ice plant which was operated until 1954 when the rising lake waters inundated the field.

In 1957, Kent Imperial Oil Company drilled Sinclair No. 1 to 4,700 feet and produced steam and hot brine. To date, 12 wells have been drilled to an average depth of about 5,000 feet, with the deepest at 8,000 feet. These wells are capable of producing an average of about 125,000 pounds of steam per hour, consisting of 20-percent flash from the brine, which contains approximately

220,000 to 260,000 parts per million (ppm) total dissolved solids, mostly chlorides of sodium, calcium and potassium. Reservoir temperatures reach about 680°F at 7,000 feet. The proved area is about 7,000 acres in size. Volume of brine in the reservoir has been estimated at 1 cubic mile.[1] Structurally, the field lies alongside the southern extension of the San Andreas fault, which borders the Imperial Valley on the east. The latter is believed to contain over 20,000 feet of primarily non-marine sediments, which may overlie oceanic crust created from sea-floor spreading along the East Pacific Rise which comes ashore beneath the continent in the Gulf of California.

The Cerro Prieto geothermal field in Mexico, about 20 miles south of the U.S. border in the same structural province, is capable of producing geothermal steam for power generation. A 75-MW plant is now under construction.

Commercial development of the Salton Sea area abounds with difficulties. Plans have been proposed to generate electric power, to recover salts from the brine, and to desalinate the brine for agricultural and municipal use. However, the poisonous residual brine cannot be disposed of into the Salton Sea or into the shallow ground waters of the Imperial Valley. Market conditions for the sale of large quantities of potash, lithia, table salt and calcium chloride are not favorable at present, and desalinization is prohibitively expensive. The extreme corrosiveness and scaling of the brine require the use of special material for pipes, valves, separators and turbines.

Robert W. Rex of the University of California at Riverside and his staff have conducted studies of the Imperial Valley between the Salton Sea and the Mexican border and have concluded that there is a possibility for the production of geothermal fluids more comparable to Cerro Prieto than to the Salton Sea. Rex is currently continuing his studies and plans to drill several deep exploratory holes if proper funding can be arranged.

The Casa Diablo area in Inyo County, California, has been partially tested by 11 shallow wells, ranging from 630 feet to 1,063 feet in depth. The largest well tested 69,000 pounds of steam and 473,000 pounds of hot water per hour. The residual fluid contains intolerable amounts of arsenic, boron and fluorine, and, like the Salton Sea, causes a disposal problem. Calcium carbonate scaling is also a problem. This field at the present time is not in the commercial category.

Brady Hot Springs, in Churchill County, Nevada, has had 9 geothermal test holes, the deepest of which is 5,000 feet. Steam and water flow temperatures exceed 300°F in the shallow wells. Calcium carbonate deposition is a problem. A heat exchanger pilot plant is currently being planned in this field.

The Beowawe Field, in Eureka and Lander Counties, Nevada, has had 11 test holes drilled. The largest well is capable of producing 50,000 pounds of steam and 1,400,000 pounds of hot water per hour at 342°F with a wellhead pressure of 116 pounds. Infiltration of cool surface water has lowered temperatures in these wells, whose average depth is around 700 feet, with the deepest hole at 2,052 feet. Maximum logged temperature is 418°F.

Yellowstone National Park is the largest and most conspicuous geothermal district in the United States. It extends for a linear distance of 40 miles. The USGS has drilled 13 holes in 6 localities. The deepest hole is 1,088 feet, and maximum temperature recorded is 460°F. Most of the test holes produced large flows of very hot water, and one produced dry steam. It is highly unlikely that any commercial development will be permitted within the park.

Steamboat Springs in Nevada, south of Reno, has had 36 test holes, many of which are only a few hundred feet in depth. Maximum temperature of 340°F was reached at 350 feet. Like many of the other areas, calcium carbonate scaling is a severe problem.

The Valles Caldera, in Sandoval County, New Mexico, has had 5 exploratory tests. The deepest well reached 5,600 feet and pre-Cambrian basement after penetrating a section of young volcanic rocks and Paleozoic sediments. Well temperatures exceeded 400°F, and flows of steam and hot water were encountered in several horizons.

Other areas where significant flows of hot water have been encountered are: Clear Lake, California; Wilbur Springs, Colusa County, California; Surprise Valley, Modoc County, California; and Klamath Falls, Goose Lake and Warner Valley, Oregon.

Development and Economics

Exploration Costs

Exploration costs have been minimal to date. Most exploratory wells have been drilled near known hot springs, and all exploratory wells that have been successful are near hot springs or hydrothermally altered rocks. Gravity and magnetic surveys are used to locate areas of interest. Shallow holes to measure temperature gradients and outline areas of surface heat have already been undertaken on a number of prospects. Of the fields discovered to date, the operators have made use of previous reports and maps of the USGS and of state surveys. Exploration costs (aside from drilling) probably average only a few thousand dollars per prospect to date. Geophysical work in the future will greatly increase total exploration costs.

Drilling Costs

Drilling costs will vary considerably with the prospects. A good example of this can be seen in a comparison of the Geysers, where the wells are drilled in Jurassic-Cretaceous, semi-metamorphosed rocks, and the Imperial Valley, where the wells are drilled in soft, loosely consolidated Quaternary sediments for the first 4,000 feet or so.

McMillan reports that the first wells in the Geysers Field, from 900 feet to 4,000 feet in depth, averaged about $40,000 per well.[3] The later wells, including those now being completed, ranging from 4,500 feet to 7,000 feet, are more expensive. Usually the upper portion of the holes are drilled with mud. Casing is then cemented and the remainder of the hole drilled with air until enough steam has been encountered to make a satisfactory completion.

Steam Transmission System

Power plants are located adjacent or centrally with respect to the producing wells. In the Geysers Field, two plants, each consisting of two units, are now in operation. The farthest wells from the plants are about one-half mile away.

Pipeline sizes vary from 8 to 16 inches, nominal pipe diameters for the wellhead lines, and the gathering system ranges from 10 inches through 30 inches. The total cost of a pipeline system in this field with all appurtenances has been in the range from $10 to $12 per KW of connected capacity. Costs include insulation, consisting of a 2-inch fiber glass blanket with a cover of 48-pound-grade asbestos felt having an asbestos backing.

Plant Costs

Table 21 shows plant installation costs in the Geysers Field declining from $141 per KW for units 1 and 2 to $105 per KW for units 5 and 6.

In 1968, the average production costs for the Geysers plants was 2.75 mills per KWH. It is estimated that the operating costs for plants 5 and 6 will average 0.45 mills per KWH. McMillan estimates total cost per KWH at the Geysers as follows:

2.66 mills = steam costs delivered to plant per KWH
0.45 mills = operating costs per KWH
1.80 mills = capital costs per KWH

4.91 mills = total costs

Consideration of inflationary and other factors evolving since the publication of McMillan's paper in 1970 would place present total costs at 5.25 mills per KWH.

Special Problems

There are a number of problems that may act as deterrents to companies contemplating geothermal exploration. One of these is the long delay between the time of completion of the first well

TABLE 21

THE GEYSERS FIELD

Unit	Capacity (MW)	Total Cost (Millions $)	Cost per KW
1-2	27	3.8	$ 141
3-4	56	6.4	114
5-6	110	11.6	105

and the time that the plant goes on production. The cost of plant construction is the largest item in the development of geothermal power, and the turbines, because of special construction, must be ordered several years in advance. Several confirmation wells (semi-exploratory) are usually needed before initial steps are taken to build the plant. In the Geysers Field, some wells drilled 5 years ago are not yet on production at this writing. It is estimated that there will be about a 2-year delay for wells currently being drilled.

A second problem is that of dissolved minerals. Of all the exploratory wells that have been drilled to date in the United States, only the Geysers has been relatively free of dissolved minerals in the effluent. One of the best examples of the problem can be seen in the Niland or Buttes Field in the Salton Sea area of the Imperial Valley, where all wells produce a brine with about 25-percent salts, creating problems of corrosion, scaling and effluent disposal. Scaling (deposition of $CaCO_3$, or SiO_2), is a problem in nearly every well that has produced hot water. Other constituents of geothermal fluids are hydrogen sulfide, fluorine, boron, carbon dioxide and arsenic. The best solution to scaling appears to be the "heat exchange" method where the produced hot fluids are kept under pressure and returned to the ground. Corrosion can be due to acidic or alkaline conditions.

At the Geysers, ammonia and boron are present in the steam effluent in small quantities, and because of this the fluid is currently, and will continue to be, injected into otherwise unused wells on the edge of the field.

The dissolved minerals in the effluent, in addition to causing problems with the operator's equipment, are also a source of pollution. Boron is harmful to agriculture and ammonia is injurious to small fish life.

A third problem involves noise from geothermal operations during the drilling and testing of wells which can be annoying to nearby residents. The noise of steam escaping from the discharge line can be deafening at close distance due to tremendous velocities of flow. To remedy this problem, mufflers have been designed and are being improved.

Review of Alternative Uses of Geothermal Energy and Their Economics

Geothermal steam has been put to many uses. In the latter part of the 19th century many health resorts and spas used natural hot springs. The sulfurous waters were believed to have a healing effect on many illnesses, especially muscular ailments and rheumatism. The hot waters were also bottled, flavored and sold for internal human consumption.

In desert areas, condensate from fumaroles and steam helps local growth of abundant grass for grazing. At Beowawe, Nevada, this is the sole use at the present time.

Space heating has been attempted in some areas, the most notable of which is at Klamath Falls, Oregon, where over 350 wells have been completed with heat exchange systems. Each well is cased, perforated, and has a U-shaped length of pipe inserted. The well is then sealed around the pipe and cool water is circulated down-well in the pipe. There it is heated naturally and carried by thermo-syphon to taps and radiators. Reservoir temperature at a depth of a few hundred feet is about 230°F. Peterson and Groh estimate heat withdrawal by heat exchanging in these wells to be 3,000 to 4,000 BTU's per second.[4] Structures heated by this method in Klamath Falls include schools, shops and homes. Space heating also utilizes steam at Boise, Idaho, and Calistoga, California.

Small communities in Nevada, California, Oregon and Idaho use geothermal water to supply heat for greenhouses. At Steamboat Springs, Nevada, the hot water is used in the manufacture of plastic explosives, but it is not suitable for large-scale utilization.

All of the above-mentioned uses appear to be less attractive and less profitable at present than power generation. Areas of high-brine concentration, such as the Salton Sea, offer many brine-formed minerals that could be marketed if the price were competitive with other sources. These minerals include, among others, potassium chloride, calcium chloride and lithium chloride.

Desalinization of salt water has been proposed by Rex in the *Imperial Valley*.[5] He suggests that it could be feasible to develop as much as 10 to 15 million acre-feet per year of brine production in the Imperial Vally, yielding at least 5 to 7 million acre-feet per year of distilled water and 20 to 30 thousand MW of electric power.

Alan D. K. Laird is currently conducting economic studies at the University of California in Berkeley on the costs of desalinization. Preliminary estimates by the Reactor Technology Group of the Oak Ridge National Laboratory suggest that if electricity were sold at 3.6 mills per KWH, water could be produced for $0.10 per 1,000 gallons. However, it is very unlikely that power can be produced this cheaply.

Exploration Techniques

At the present time, basic exploration methods are most commonly used in exploring for geothermal resources. Areas of young, volcanic rocks are sought and mapped. Hot springs, fumaroles and areas of surface heat alteration are noted. Springs are sampled and water analyzed for dissolved mineral content that may indicate the presence of hot fluids at reasonable drilling depths. Magnetometer and gravity surveys are made covering the areas of interest. In some, shallow holes have been drilled to obtain sub-surface temperatures data.

New techniques have been developed in the past few years that may be useful in the future in localizing geothermal prospects. Several new geophysical tools have potential, including electrical resistivity surveys (which have already had some success in New Zealand), micro-earthquakes and low amplitude seismic surveys.

Remote sensors offer a quick way to get an overall picture of a large area and to pinpoint areas for further detailed work. This type of survey may be effective in inaccessible areas such as jungles, rough tree-covered terrain and areas with poor outcrops. Infrared surveys at the Geysers, Casa Diablo and other known areas of geothermal production have checked the known hot spots and mapped them in greater detail in some instances than can be done with on-ground inspection.

Impact of New Technology

Many of the exploratory wells drilled to date have discovered steam and hot water, but with too low a temperature to justify the construction of a conventional geothermal steam generating plant. Many of these same wells have also produced fluid that causes scaling by precipitation of silica and calcium.

At the present time, a pilot plant has been designed and may be put in operation at Brady, Nevada, to test the feasibility of using a heat exchange system to produce power. Instead of using steam to drive the turbines, isobutane in a closed system is heated by hot geothermal water and flashed to vapor. In this plant, the hot water from wells will enter the plant at a temperature of 325°F and be discharged and reinjected back into a well at a lesser temperature under pressure.

The heat exchange system, if successful, can be used in a number of areas in the western United States.

Summary and Conclusion

An estimate has been made of the amount of geothermal power that will be available in 1975, 1980 and 1985 and the cost of developing this power. An 85-percent load factor has been used.

Cost per KWH	Power Capacity in Megawatts 1970	1975	1980	1985
$0.525	82	1,500	4,500	7,000
$0.575			4,000	7,000
$0.625			2,000	5,000

These figures are based on the experience factor at the Geysers Field in Northern California where 192 MW are currently being produced, where 100 MW will be added each year for the next few years and very likely through 1985. A number of other areas in the western states have favorable surface indications such as fumaroles, hot springs and recent volcanic rocks. Over 200 exploratory wells have been drilled for geothermal energy to date. Most of these wells encountered hot water and/or steam; but in many cases contaminants in the form of brine, $CaCO_3$ scaling, arsenic and boron have prevented commercial development to date. Other exploratory wells were not drilled deep enough. A number of hot areas have yet to be drilled. New technology (i.e., heat exchangers) may enable hot water with lower temperatures than in the fields now being developed to be successfully used for energy production.

Encouraging factors for geothermal power development are (1) low cost, (2) the availability of large areas for prospecting including the recently opened federal lands, (3) the support of the Federal Government in research and possible support in exploratory drilling operations, and (4) comparative non-polluting qualities.

Negative factors, mostly minor, are (1) the costs and time lag involved from discovery to generating plant and transmission line completion and (2) the opposition of over-enthusiastic environmentalists.

Donald E. White predicts that for every vapor-dominated geothermal system discovered there will be 20 hot water systems found.[6] As there are no hot water system fields not on production in the United States, we have no cost data for comparison with the Geysers.

A comparison of geothermal power costs with other sources of power indicates that on a KWH basis, geothermal power is cheaper than fossil fuel, slightly cheaper than nuclear, but a little more expensive than hydropower. The latter source is very limited due to the scarcity of undeveloped dam sites in the United States. These comparisons suggest that any new geothermal fields discovered should find a ready market and that exploration for this type of energy should be encouraged.

Comparison of Costs for Geothermal and Other Sources of Power

	Kaufman Mills/KWH
Geothermal	5.25
Thermal	6.14
Nuclear	5.49
Hydropower	4.78

LONG-RANGE POTENTIAL FOR GEOTHERMAL ENERGY RESOURCES IN THE UNITED STATES

This section aims at defining how important geothermal energy may become in the United States from a long-range point of view. A broad geophysical appraisal of the relevant heat phenomena in the crust is presented.

Most of the published appraisals of geothermal energy are restricted to hydrothermal systems of rather local extent, which probably are related to shallow volcanic activity. D. E. White has made an appraisal of world geothermal resources, particularly those in the United States, by focusing on such localized hydrothermal systems and projecting from current developments.[25] C. J. Banwell has given estimates for the world potential of localized hydrothermal resources, relating their heat flow to the rate of Pacific-type volcanism.[8]

On the other hand, some investigators have drawn attention to the geothermal resources of deep sedimentary basins. T. Boldizsár has discussed the vast geothermal resources of the Hungarian basin, where at present there are 80 low-enthalpy geothermal wells delivering energy at a total rate equivalent to 440,000 KW.[11] In the United States, R. W. Rex and collaborators have been investigating the geothermal resources of the Imperial Valley area--which combines features of a localized hydrothermal system and of a sedimentary basin--and have extended a similar reasoning to other sedimentary basins.[20]

The following tabulation summarizes the various power estimates which are mentioned in the text.

Comparison of Orders of Magnitude of Certain Power Estimates

	Power (Watts x 10^{12})	Quadrillion BTU (10^{15}) Per Year
Geothermal Energy Flow At Surface-- U.S.A. Land Areas	0.58	17
Power Consumption U.S.A.--1970	2.27	63
Geothermal Energy Flow--Earth's Surface	26.0	777
Power Consumption World--1968	5.6	167

Various heat estimates mentioned in the text are summarized in the tabulation below.

Although relying heavily on published information, this report is not a compilation of opinions, but rather an independent assessment of the problem. We have benefited much by discussions with Gunnar Bodvarsson, W. C. Diment, Arthur Lachenburch, R. W. Rex and Donald White.

Comparison of Orders of Magnitude of Certain Heat Estimates

	Heat (Calories x 10^{20})	Heat Quadrillion BTU's (10^{15})
In Situ Sensible Heat* of Localized Hydrothermal Systems, to 3 km (1.9 miles) Depth--U.S.A.	1.4	560
In Situ Sensible Heat* of Localized Hydrothermal Systems, to 10 km (6.2 miles) Depth--U.S.A.	7	2,800
In Situ Sensible Heat* of High-Enthalpy Interstitial Waters in Sedimentary Basins Deeper than 4 km (2.5 miles)--U.S.A.	160	64,000
In Situ Sensible and Latent Heat* of Magma Chambers Reaching to Few Kilometers from Surface--U.S.A.	300-1,000	120,000-400,000
In Situ Sensible Heat* of Low-Enthalpy Interstitial Waters in Sedimentary Basins Shallower than 4 km (2.5 miles)--U.S.A.	1,600	640,000
In Situ Sensible Heat* of Cratonic and Platform Rocks to 10 km Depth (6.2 miles)--U.S.A.	50,000	20,000,000
In Situ Sensible Heat of High-Enthalpy Interstitial Water in a Sedimentary Column 1 km Thick, 100 km x 100 km in Area (2400 cubic miles)	1	396
Heat of Combustion of 1 Million Barrels of Oil	0.000014	0.0058

* With respect to surface temperature as datum.

Broad Aspects of Earth's Thermal Conditions in Crust and Upper Mantle

Temperature observations in wells and underground excavations demonstrate that temperature increases with depth. Moreover, generally accepted views about the constitution of the earth indicate that the temperature continues to increase steadily towards the earth's central region. As a result, there is a general pattern of heat flow from the earth's interior towards the surface.

The power represented by the flow of heat reaching the entire earth's surface is on the order of 2.6×10^{13} watt, which, although substantial, is not too much larger than the present rate of energy consumption by man's activities, namely about 5.6×10^{12} watt. The rate of energy consumption in the United States for 1970--including coal, oil, gas and water power--was equivalent to a power of about 2.27×10^{12} watt, in comparison to 5.8×10^{11} watt for the heat flow in the entire United States. Inasmuch as the average rate of geothermal heat flux per square kilometer on continental areas is equivalent to about 63 KW, a large area is required to obtain an appreciable amount of geothermal power by intersecting the heat flow.

Moreover, as the flux of geothermal energy per unit area is only a small fraction of the radiation energy received from the sun, it may seem, in a casual analysis, that geothermal energy may not have as high an ultimate potential for producing power for man's activities as the sun's radiation.

However, the sensible heat of the crustal rocks represent a heat reservoir of considerable magnitude. That is, the relatively small rate of heat flow is compensated by such storage. The opposite occurs with solar energy--a relatively large heat flow but almost no storage. If heat is withdrawn from a certain volume of rocks, in general it would take considerable time for the temperatures to practically regain their initial values. The times that are involved may run into the thousands or millions of years.[13,14] Because of this, the process has been referred to as "mining the heat."

The heat flow is far from uniform over the earth's surface and may vary by as much as 1:1,000. Therefore, local areas with much higher-than-normal heat flow are of special significance for power generation. Such "hot spots" have been found in volcanic areas of recent tectonic activity. Also, perhaps they may occur in areas underlain by mantle rocks of an exceptionally high thermal conductivity.

To measure heat flow a unit designated as a heat flow unit (HFU), equal to 1 millionth calorie per square centimeter per second (10^{-6} cal cm^{-2} sec^{-1})* has been introduced in the literature and is to be used for the values of geothermal heat flow given in this paper.

Lubimova, commenting on the more than 2,600 heat flow determinations that were available, indicated a geometric mean of 1.36 HFU for the continental areas and a geometric mean of 1.27 HFU for

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* (Equivalent to 0.419×10^{-5} watt cm^{-2}.)

oceanic areas.[19] The global "normal" value would be in the range of 1.2 to 1.5 HFU.

Lee and Uyeda[18] and Roy et al.[21] summarized heat flow determinations in the United States, considered reliable for the purpose, and categorized them according to major physiographic provinces. The average heat-flow value reported for the Interior Lowlands is 1.25 ± 0.18 s.d.* HFU, with individual values about 40 percent higher than in the Canadian Shield, where they range from 0.69 to 1.07 HFU with an average of 0.88 ± 0.13 s.d. HFU. In the Appalachian system the heat flow ranges from 0.73 to 1.4 HFU, with an average of 1.04 ± 0.23 s.d. HFU. In the Cordilleran region, which is defined in this case as the area west of the Rocky Mountain front to the Pacific Coast, the heat flow ranges from 0.62 to 5.32 HFU, with an average of 1.73 ± 0.53 s.d. HFU. In general, the Cordilleran region has the highest heat-flow values of the above mentioned four provinces. In particular, the Basin and Range Province has values generally larger than 2 HFU.

More recently, Roy et al., using about 135 new heat flow measurements, further defined the outline of thermal provinces in the United States. They attribute the areal variability of the heat flow within a given province mainly to areal variability of the bedrock radioactivity, and regional deviations of the mean heat flow within a province from the "normal" or overall mean to temperature anomalies at the crust-mantle boundary. For instance, the high heat-flow values for the Basin and Range Province would be due to abnormally high temperatures at the base of the crust. They attribute the large areal fluctuations of heat flow in New England and New York to areal fluctuations of bedrock radioactivity.[21]

Birch, Roy and Decker have demonstrated the existence of a statistical linear relation between the surface heat flow, denoted by Q, and the rate of radioactive heat production in surface rocks, denoted by A, of the type

$$Q = a + bA,$$

where a and b are constants.[9] We note that b has the dimensions of depth, so it can be considered to be an effective depth of the distribution of radioactivity. The HFU is used for both Q and a, the unit for A is 10^{-13} cal cm^{-3} sec^{-1}, and for b is cm. Such a linear relation can be foreseen by considering heat-flow models (Grossling, 1951, p. 49).[13]

For the distribution of radioactivity with depth, two functions have been proposed:[21,20] (1) radioactivity constant down to a depth b, and (2) radioactivity decreasing with the depth z as $\exp(-x/b)$. In the second model, b can be viewed as an effective depth of the distribution.

* s.d. = standard deviation.

Roy et al. have investigated the surface distribution of heat flow in the United States, and have analyzed it using the linear relation (1).[21,22] They distinguish, based on a categorization of "reduced" heat flow values--that is, the subcrustal component of the heat flow calculated by the relation $a = Q - bA$--three major geothermal provinces:

- Eastern United States, $a = 0.8 \pm 0.1$ HFU
- Basin and Range Province, $a = 1.4 \pm 0.1$ HFU*
- Sierra Nevada Province, $a = 0.4 \pm 0.04$ HFU.

For the Franciscan block east of the San Andreas fault, in the Pacific Coast Ranges, very high values of a are found, namely 1.9-2.1 HFU.[26] The rather narrow range of variation of the a values within each of these provinces suggest that the heat flow from the mantle is constant within each province.[22]

The prospects of geothermal energy seem to be particularly interesting where the heat flow is regionally high, say greater than 1.5 HFU. In the United States, these areas are found mainly in the West. The Northern Rocky Mountain Province is characterized by uniformly high values, averaging 2 ± 0.1 HFU. The Columbia Plateau may also be a high heat-flow area. In the southern Rocky Mountains the heat-flow values are generally larger than 1.6 HFU. In the Basin and Range Province they are uniformly high, generally over 1.5 HFU, and averaging about 2 HFU. Other high heat-flow areas identified in the West are: the Franciscan belt east of the San Andreas fault, the Black Hills and parts of eastern Wyoming.

Now, when appraising the significance for geothermal energy of a regional excess heat flow over the normal value, it is very important to distinguish whether the excess heat originates in the radioactivity of crustal layers or whether it originates higher-than-normal temperature at the crust-mantle boundary. Simple models, in which a uniform distribution of radioactivity and constant thermal conductivity are assumed, are useful.[14,17] For a radioactive crust, the steady-state excess temperature increases as a quadratic function of depth, with the gradient steadily decreasing to a zero value at the base of the radioactive layer. On the other hand, for an excess heat from the mantle. the steady-state excess temperature increases linearly with depth throughout the crust.

Specifically, we can assume a constant thickness of the radioactive crust, and two alternatives about the origin of the excess heat: (1) due to an excess of radioactive content, as compared to the normal crust, and (2) due to an excess of heat flow from the mantle as compared to the normal condition. For these assumptions, it can readily be shown that the temperatures throughout the crust would be higher when the excess heat comes from the mantle, this to the extent that the excess temperature at the base of the radioactive crust is twice that when the excess heat originates in the

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* Excluding some high values attributed to local anomalies.

radioactivity of the crust. Moreover, the total amount of heat stored as sensible heat in the radioactive crust is 50 percent greater when the excess originates in the mantle than when it originates in the radioactive crust. More complex situations can also be considered. However, the simple models are enough to show that high "reduced" heat-flow areas are more important, because of higher crustal temperatures, than areas where there is high heat flow because of an excess crustal radioactivity.

Calculations on theoretical models indicate that the times required to practically reach the steady-state for the dimensions of the crust are at least on the order of 50 to 100 million years. That is, since geosynclinal belts can undergo orogenic cycles at shorter time intervals, deviations from the steady-state may be important. If one examines the way the temperature builds up for the two above-mentioned models (Grossling 1959, Figures 12 and 13),[14] it can be established that the temperatures in the deeper parts of the crust increase somewhat faster for the model when the excess heat originates in the mantle than when it originates in the crust, thus adding somewhat to the advantage, from the point of view of geothermal resources, of high "reduced" heat-flow areas.

The Basin and Range Province is particularly important for geothermal energy. As Roy et al. have shown, it has a very high "reduced" heat flow (1.4 HFU, in comparison to 0.8 HFU in the eastern United States, for instance).[21,22] On the other hand, the excess heat flow in the southern Rocky Mountains seems to originate in an excess of crustal radioactivity.[12]

A Geothermal Survey of the United States

In making an appraisal of the geothermal resources of the United States, the first task would be to define its major thermal provinces. To do this would require a greater number of reliable heat-flow measurements than are now available, not merely temperature gradients. The work already done, mentioned in the foregoing discussion, demonstrates the existence of thermal provinces, but their boundaries are not sufficiently well defined, nor is it likely that all the provinces have already been recognized. For such definition it would be valuable to have a grid of heat-flow measurements, made at carefully selected sites, using suitable techniques, and followed by the necessary reductions and corrections. The grid could consist of about 3,000 geothermal holes spread on a square grid at about 30-mile spacing and about 500-foot depth.

We note that at present the number of heat-flow measurements in the United States considered reliable by heat-flow experts is only a little over 200. Including those in preparation, they may amount to only about 350 measurements.[24] By now the backlog of suitable data from deep wells drilled in the past, on which such data has much depended, is practically exhausted, and new wells of the kind suitable for heat-flow determination become available at a small pace.

General requirements for heat-flow measurements are set forth in a discussion of Roy et al.[21] The borehole depth should be roughly 200 m. Inasmuch as the temperature profile in the uppermost 100 m is usually disturbed, the lower 100 m segment is to be used for the heat-flow determination. The temperature is to be measured at 10 m discrete intervals with an accuracy of ± 0.05°C, and the mean gradient determined by least squares for the lower 100 m segment to an accuracy of 1 percent. The standard error of the mean thermal resistivity determination is to be less than 1 percent. A steady-state correction for topography is to be applied, when necessary.

Localized heat-flow measurements can define promising geothermal areas, as the Battle Mountain High in Nevada.[23]

In addition, a compilation of existing temperature well data, such as the Geothermal Survey of North America sponsored by the American Association of Petroleum Geologists (AAPG), is useful.[15] Much data may be gathered in this way--already raw data for about 50,000 sites has been gathered. But to properly interpret the temperature data, the broad fabric provided by heat flow measurements is required.

Finally, areas of specific interest should be detailed by a dense grid of shallow temperature wells, such as is being done in Imperial Valley.[20]

General Features of Geothermal Resources

The presence of water in a permeable bed is of great practical importance because it allows a much faster withdrawal of part of the sensible heat of the formations than heat conduction would. Yet, of the sensible heat of a formation saturated with water, only a small fraction is withdrawn with the fluids because of the small porosity of geologic formations. That is, if the reservoir is tapped only once it would yield only a small fraction of its sensible heat. A higher fraction may be withdrawn by either reinjecting the condensate after the steam has been used to produce power or by withdrawing the water at a rate consistent with the natural influx of water from surrounding formations.

The heat from an underlying magmatic mass raises the temperature of the overlying rocks and contained fluids above the values normal for their depth. In this manner, reservoirs of hot water, and of steam may develop at certain places in the rocks covering a magma chamber.

Some of these reservoirs have become completely sealed, probably because of chemical deposition around their periphery. Others may be partially closed by hydrodynamic conditions, and still others may be hydrodynamically open. Depending on the temperature/depth relationship, the reservoir may exhibit either a hot-water phase, hot-water and saturated steam phases, or only a dry-steam phase.

Most current utilizations of geothermal energy hinge on the presence of hot water or steam. The steam produced from a geothermal field, and to a lesser extent the hot water, may be used to generate electric power. Because of their higher thermal efficiency, multiple-stage steam turbines, with condensers, are preferred to other prime movers. To be able to use a steam turbine when the reservoir produces only hot water, a two-fluid system with a heat exchanger has been used. One fluid system corresponds to the geothermal fluids, and the other to a low-boiling-point fluid that operates the turbine.

Hot water is also used simply as a source of heat for space heating and for some industrial processing.

The condensate obtained from a steam reservoir may be utilized as a source of fresh water, which can be very significant in arid regions such as the Southwest of the United States. Alternately, the condensate could be rejected thus to withdraw a larger percentage of the sensible heat of the reservoir.

In this report the energy estimates for geothermal energy are given in calories to emphasize that the geothermal energy is mostly in the form of heat. As such, it can compete in the heat market itself. When comparing it against combustion of fuels, one has to reduce the heat of combustion by the efficiency of the furnace.

On the other hand, if electricity is desired, then one has to reduce the geothermal energy figures by the efficiency of the conversion of heat into work. This efficiency cannot surpass $(T_2 - T_1)/T_2$ where T_2 and T_1 are the absolute temperatures of the intake and outgoing fluids, respectively, in the device. For instance, if the geothermal water is at 250°C and the ambient temperature is 10°C, then the maximum thermodynamic efficiency is 240/523 = 0.46 (46 percent); whereas, if the geothermal water is at 150°C, then the thermodynamic efficiency is 140/413 = 0.34 (34 percent). To produce electricity it is thus better to have high-enthalpy waters. Moreover, the efficiencies attained in practice are much lower than the theoretical maximum.

The actual manner of utilizing the enthalpy of the geothermal water may introduce another loss factor. If the geothermal water is flashed as it comes to the surface to produce steam for a turbine, then a fraction of the mass of water is converted into steam and the remainder of the mass remains as liquid. The dissolved solids would remain in the liquid, with an increase of salinity. The proportion of the geothermal water that is flashed into steam increases with the temperature and, for the usual range of temperatures, would be in the range from two-thirds to three-fourths of the total mass. But, if a heat exchanger is used between the geothermal fluid and the steam turbine, then we do not have to deduct from the mass of geothermal fluid available that remain as bittern.

Now we come to the question of how much of the geothermal waters in a sedimentary basin may be recovered. Elastic expansion of the interstitial water upon decrease of bottom-hole pressure in a well, provides a driving mechanism. Boldizsár estimates that about 1 percent of a given mass can be driven by its elastic expansion and the elastic compression of the matrix.[11] More fluid might be obtained by such a mechanism were the geothermal water connected to other water bodies, for example, in the development of a tract in a basin, relatively small with respect to its total dimensions, surrounded by much larger water masses connected to it. A further amount could be obtained by compaction and plastic deformation of the solid matrix upon decrease of the water pressure. A scheme of removing hot water at one row of wells and injecting cold water at another distant row of wells would provide other mechanisms of obtaining a large fraction of the *in situ* geothermal fluids. Finally, by decreasing the bottom-hole pressure, part of the enthalpy of the geothermal water can be used to provide the lift to the surface.

The above-mentioned mechanisms may yield a fraction of the *in situ* mass equal to 10^{-2} to 10^{-1}, or even greater. As we shall see, the magnitude of the *in situ* reserves is so large that a factor of 10^{-2} to 10^{-1} still yields substantial recoverable amounts.

A Plowshare Proposal for Developing Geothermal Energy

The proposal for electricity generation, referred to as the Plowshare Geothermal Power Plant, sets forth the utilization of the sensible heat energy of impermeable rocks in a thermal anomaly of the earth's crust. In order to fracture the rock formations, clusters of nuclear explosions would be sequentially detonated inside the geothermal field. Water would then be introduced and circulated from the surface into the fractured zones and cavities produced by the explosions to produce hot water and/or steam. The water and/or steam would be used to drive the steam turbines of an electric power plant.

A feasibility study prepared by the American Oil Shale Corporation, Battelle-Northwest and Westinghouse Electric Corporation describes such a geothermal power plant. In the thermal anomaly assumed in that report, the rock temperature would be 350°C at a depth of 3 kilometers (km). That is, a geothermal gradient of 113°C/km (291°F/mile) is required.[7]

For the power plant, an installed capacity of 200,000 KW was assumed. The number and yield of the nuclear explosions was selected so as to produce a volume of fractured rocks sufficient to provide the heat energy for a 30-year operation of the plant. For the yield of the individual nuclear devices, three sizes were considered: 200 kiloton (kton), 500 kton, and 1 megaton. * For the

* A 1-kiloton explosion releases energy equal to that in the explosion of 1 thousand tons of TNT. A megaton has an explosive force equivalent to that of 1 million tons of TNT.

1-megaton explosive size, either a pattern of 14 one-megaton shots would be fired sequentially to develop one field; or, alternatively, three fields of 4 one-megaton shots each would be fired.

The total cost of the electric energy generated increases with a decreasing yield of the individual explosives used to develop the field. That is, economics indicate the larger yields. However, considerations of safety would limit the size of large explosions.

Depending on a number of alternative designs which are presented in the feasibility study, the estimated cost of the electricity generated would be as follows:

Mills/KWH ($0.001)	Individual Explosive Size
12.0	200 kton
7.6	500 kton
6.4	1 megaton

The exceptionally large values for the thermal gradient assumed--namely, 113°C per kilometer--have been found only in areas with active volanic activity, or which probably are underlain by active magmatic chambers at shallow depths in the earth's crust. On the other hand, the site is assumed to be in a tectonically stable area, which seems to be an essential condition for avoiding triggering damaging earthquakes or inducing magmatic eruptions.

To decrease earthquake and eruption risks, a sufficiently small explosive size would have to be used; however, the economics of the project deteriorate with decreasing explosive size. In fact, for the 1-megaton individual explosives the economic competitiveness of the Plowshare Geothermal Plant is already marginal with respect to large-scale power generation, such as the large coal-fired power plants now being developed in the Southwest. For the 200- and 500-kton sizes the cost of the electric energy would be noncompetitive, under normal conditions.

Moreover, the economic conditions of the project would preclude increasing the depth of the thermal anomaly, in order to utilize an area with a substantially smaller thermal gradient. The above-mentioned feasibility report examined only cursorily the risks of triggering earthquakes and inducing volcanic explosions because it assumes that only a stable crustal area would be utilized.

But what is involved in the proposal examined is, in fact, the shooting of about 14, one-megaton explosions in areas such as the Geysers in California or Cerro Prieto in Baja, California. For such areas, the risks of earthquakes and eruptions seem considerable.

The above described inconsistency of assumptions in the Plowshare proposal raises important questions. The utilization of nuclear explosions in platform and cratonic areas needs further investigation. Other power plant sizes should be examined to determine the economically optimum size.

Long-Range Prospects for Geothermal Energy Resources

How much geothermal energy is there? The answer depends on the point of view and on a number of qualifications.

Various attempts have been made to estimate the magnitude of the total energy that may be recovered using the heat of the earth. This report describes, in a preliminary way, some of the efforts in this direction.

A widely quoted estimate of geothermal resources is based on the calculation of the accumulated heat in "localized hydrothermal systems." Such sealed-steam or hot-water reservoirs are locally the most important sources of geothermal energy. If they are tapped once without recirculation, and without waiting for the natural water recharge, their life spans would be only a few decades. A longer life span may be achieved by adjusting the fluid withdrawal after proper consideration of condensate reinjection, natural water inflow and heat flow from the underlying magma chamber. A surmise as to the number of such reservoirs in the United States, based on the indications of shallow volcanic activity, would suggest it to be more than 10, but not much greater than 100. Unless a reservoir is located, at the most, within a few hundred meters from a magma chamber, its life span is in effect determined by the sensible heat initially in place. On the other hand, if it is sufficiently close to a magma chamber, there may be significant reheating of the reservoir in a lapse of a few years or decades; and thereby its life span as a source of energy would be considerably lengthened. We note that the time of cooling of a magma chamber is measured by time spans of thousands to millions of years.

The heat above surface temperatures in hydrothermal systems in world land areas has been estimated at 2×10^{21} cal down to a 3-km depth, and 1×10^{22} cal down to 10-km depth.[25] Of these totals, 5 to 10 percent would be in the United States. Estimates of the percentage of this heat that might be recovered by producing the fluids vary from about 10 to 70 percent. For these estimates, surface temperature is taken as datum.

Furthermore, a too casual analysis of the published estimates for the localized hydrothermal systems has led to a figure of 50 years for the life of the geothermal energy. Before accepting any prognosis of such short life, a more thorough analysis of the heat-transfer mechanisms in localized hydrothermal systems seems to be needed. A careful estimate of the potential of these systems would indicate for the United States an energy sufficient to sustain a generating capacity of 10,000 MW on a continuous basis, rather than for only 50 years.[8]

Other sources of heat that must be considered are--

- Interstitial thermal waters in sedimentary basins
- Magma chambers in the crust
- Sensible heat of rocks in cratonic areas
- Sensible heat of rocks in orogenic belts
- Sensible heat of rocks in the oceanic crust
- Interstitial thermal waters in thick sedimentary pods in the ocean basins.

The thermal energy of the water in sedimentary basins is appreciable. The sedimentary basins of the conterminous United States have a total area of about 1.9×10^6 mi^2, or about 60 percent of the total area. In other words, the total sedimentary volume is on the order of 8×10^6 mi^3. The maximum depth to basement may be as high as about 60,000 feet. Of the total volume, perhaps about 5×10^5 mi^3 lies below 4-km depths, and about 7.5×10^6 mi^3 above it. Assuming that the pore space is filled with water, a mean temperature of 150°C (≃ 300°F), and an average porosity of 5 percent, one readily obtains for the total *in situ* heat of the interstitial water below 4 km the value 1.6×10^{22} cal. The considerable magnitude of this total can be appreciated by comparing it with the heat of combustion of 1 million barrels of oil, which is about 1.4×10^{15} cal. That is, the total sensible heat stored in interstitial waters of sedimentary basins of the United States below depths of 4 km may be on the order of the heat of combustion of 10 trillion barrels of oil. The figures for the low-enthalpy waters above 4 km are an order of magnitude greater. The amounts of recoverable heat are obtained by multiplying the above *in situ* figures by a factor which may range from 10^{-2} to 10^{-1} as we have discussed before. Thus, the recoverable amounts are still considerable.

In comparing the above estimates for the sedimentary basins with the heat in localized hydrothermal systems, one should note an important difference. The figures for the total heat of localized hydrothermal systems should be reduced (to a value of 10 to 70 percent) to obtain the heat that may be recovered with the fluids; whereas, the total enthalpy of the fluids in sedimentary basins corresponding to the temperature difference with respect to surface temperatures could be recovered, and moreover a multiple of it by reinjection of water. The heat energy that may be recovered from thermal waters in sedimentary basins is probably two orders of magnitude (10^2) greater than that of the localized hydrothermal systems.

Recent volcanic areas are probably underlain by one or more chambers filled with molten rock , or magma. The dimensions of these chambers may be on the order of several kilometers across, and they may lie from a few kilometers under the earth's surface to greater depths, either in the crust or upper part of the mantle. The emplacement of a body of magma at shallow depths, and originating at much greater depths, represents a much greater transfer of heat than would be possible in the same time interval for thermal conduction alone. Moreover, convection inside a magma chamber further facilitates the transfer of heat from the deeper parts of the crust, or even from the upper mantle.

Although the energy content of a large magma chamber (as sensible and latent heats) is quite large, and despite the fact that some may be within reach of present drilling techniques, no thought seems to have been given thus far to the tapping of this energy. In fact, the heat being recovered is only a side effect of the emplacement of a magmatic body. In the rocks covering centers of volcanic activity, sealed deposits are often found of permeable and stratified formations with water.

Magma chambers are likely the heat sources that account for the heat of the localized hydrothermal systems. We estimate, based on speculation as to the number of still-alive magma chambers and on the likely dimensions of a typical chamber, that the heat content of the magma, in chambers in the United States reaching to 3 to 5-km depth, is on the order of (3 to 10) 10^{22} calorie.

No magma chamber has yet been exploited anywhere for its heat, nor for anything else. However, in the literature there are already indications that consideration is now being given to the problem of using such heat energy. We expect that means will be developed to utilize the thermal energy of these magma chambers within a few decades.

The heat stored in crustal rocks in cratonic (volcanic) and platform areas could be exploited by means of fracturing techniques, perhaps utilizing nuclear explosives and circulation of water. Such heat, above surface temperature, in the United States down to 10-km depth, is on the order of 5 x 10^{24} calorie.

Locally, the heat stored in crustal rocks in orogenic (mountain forming) belts may be effectively utilized when there is an adequate aquifer system. Yet, the total heat that may be tapped in this manner would be perhaps one or two orders of magnitude smaller than that for the cratonic areas. No estimates have been made as yet for the geothermal resources of the oceanic areas.

Now, the words of caution. The above estimates for the amounts of heat stored in various items of the crust of the United States are not reserve figures, nor even resource estimates. Rather, they are upper bounds for the prospective level of the resources, once a number of previous issues are further investigated. First is the question of the economic profitability of operations for utilizing the geothermal heat. Then, there are issues to be settled about actual conditions in the subsurface. For instance, regarding the high-enthalpy waters in the deeper parts of basins, we need better knowledge of: volumes of interstitial water that may be produced by means of wells, average temperature of the water, depth range of the wells required, reservoir mechanics of geothermal reservoirs, salinity of the water, etc.

Nonetheless, it would seem that the heat that may be recovered from high-enthalpy masses of water in the deeper parts of sedimentary basins of the United States could be of considerable magnitude. It seems conceivable that it may overshadow even the overall total for oil. The petroleum industry, in particular, because of its familiarity with basins, seems to be in a strategic position to take advantage of these opportunities.

The above mentioned heat estimates are compared in the tabulation "Comparison of Orders of Magnitude of Certain Heat Estimates."

Conclusions

Geothermal electric power generation, at favorable geologic sites, has been found to be feasible and competitive with other commercial sources of energy. It can make a significant contribution to the power supply of certain regions of the Nation, especially in the West. However, geothermal resources are only beginning to be developed. As yet, the only geothermal development of considerable size in operation in the United States is the Geysers, California. At present it has an installed capacity of 83,000 KW, which may be increased to 500,000 KW by 1975.

Moreover, the exploitation of geothermal resources can have additional economic benefits because of: (1) utilization of geothermal heat as such (in industrial processing, agricultural heating, water desalination, space heating, etc.); (2) production of fresh water from geothermal fluids; and (3) recovery of certain chemicals from geothermal fluids. That is, in arid regions the economics of geothermal exploitation should be examined jointly for power production, production of fresh water and production of chemicals if the fluids are rich in salts.

Air pollution, in general, is not a serious problem with geothermal energy because there is no combustion of fuels. However, in some cases, hydrogen sulfide and other gases may give cause for concern. Water pollution can be a problem because of objectionable amounts of certain chemicals in the bitterns.

The limiting factors in the development of geothermal energy seem to have been, not economics, but rather the novelty of the idea, a lack of sufficient pre-investment geological and geophysical evidence of the extent of the geothermal resources, and, until recently, the fact that a large fraction of the geothermal prospective lands could not be leased for that purpose.

How much geothermal energy can ultimately be developed, and how long it would last is, at present, hard to say. Much has to be learned of actual thermal conditions and processes in the continental crust and upper mantle. The mere projection of present developments would indicate at least a 10- to 50-fold increase, within a decade, of present total installed-plant capacity. Simple calculations, based on the thermal energy already within localized hydrothermal fields, indicate life spans of about 50 years. However, considerably longer life spans may be met, depending on the actual heat transfer mechanisms that take place underneath these fields, about which much is yet to be learned.

The magnitude of the geothermal reservoirs exploited until now--namely, sealed steam reservoirs--permits the installation of power plants of considerable size, on an order of magnitude of approximately 500,000 KW.

How many such sites may be discovered in the United States cannot be definitely ascertained because of insufficient exploration. A guess would be that their number may range between 10 and 100.

Areas with much higher-than-normal heat flow are of special significance for power generation. Such "hot spots" are found in volcanic areas and in areas of recent tectonic activity, mainly west of the Rocky Mountain front. Sealed reservoirs of hot water and steam often occur at certain places in these areas.

A potentially far greater heat reservoir than the localized hydrothermal system is represented by waters permeating the sedimentary basins. However, the bulk of the waters are of low enthalpy (temperature < 150°C), and only a fraction are of high enthalpy (temperature > 150°C). The latter are more important for electric power generation.

How large these high-enthalpy hydrothermal resources are in sedimentary basins of the United States hinge on a number of questions not totally resolved, such as (1) volumes of high-enthalpy waters that may be retrieved by wells, (2) average temperature of these waters, and (3) economics. Porosity, permeability, bed thickness, lateral continuity and other factors determine the amount of water that may be retrieved by wells. These quantities are not well known for the deepest parts of sedimentary basins, which are the most important. The simple projection of surface temperature gradients in sedimentary basins generally gives an underestimate of the temperatures at the deeper parts of the basins. This is because surface gradients are depressed due to subsidence and sedimentation.[14] The economics of the exploitation of the high-enthalpy water would depend on the depth range of the wells, production characteristics of the wells and on the nature of the solids dissolved in the waters.

Where a sedimentary basin is found over a "hot spot," such as in the Imperial Valley/Mexicali Valley area, the potential to produce power can be very important.[20]

A particularly important objective is finding sedimentary basins with large volumes of interstitial waters in their deep parts, which overlie areas with an abnormally high temperature of the mantle-crust boundary. The Gulf Coast geosyncline is perhaps the most important exploration target in this respect.

If an area of 100 km x 100 km were found, underlain by a layer within the sedimentary column containing permeable beds with an average porosity of 5 percent in a thickness of one kilometer, of 250°C average temperature, then the heat of the water, over surface temperature, is on the order of 10^{20} cal, which is equivalent to the heat of combustion of 90 billion barrels of oil. That is, even if only a small fraction of the water could be retrieved, the magnitude of the recoverable energy would still be considerable.

To disclose whether geothermal resources can actually attain the importance suggested by the estimates in this report, an R&D effort is required to clarify or solve the following issues:

- What is the magnitude of the *in situ* geothermal resources?
- How much geothermal energy can be utilized?
- How long will the geothermal resources last?
- Can technologies be developed that would allow a fuller utilization of geothermal resources?

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Chapter Four

ENERGY FROM AGRICULTURE

SUMMARY

U.S. agriculture as a primary energy resource will contribute to the Nation's energy supply to a small extent in the near-term where local conditions are especially favorable. For many reasons --including the size of the component resource bases and technical, economic and social factors--agriculture can make no significant contribution to the U.S. energy supply before 1985. Forests and woodlands, which constituted the principal fuel resource in the last century, now contribute less than 2 percent. Agricultural residues and by-products, if all were collected and dried for use as primary fuels, would represent about 3 percent of the projected 1980 U.S. demand. The total of all animal wastes, if dried and used as fuels, would represent about 1.6 percent of the 1980 U.S. energy demand. If all of these potential agricultural residues, by-products and animal wastes were converted to gas by a process of fermentation, the total heating value would be about 2.6 quadrillion BTU's per year, as compared with 4.6 quadrillion BTU's per year if burned as primary fuels.

The growing of cultivated crops specifically for use as direct burning fuels is not attractive by present technology. However, the cultivation of cereal grains for the production of industrial alcohol could, with current technology, be an economic alternative to supplement gasoline in the increasingly short petroleum supply situation before 1985. The quantity of energy that could be made available in the form of ethyl alcohol from cereal grains would be dependent upon the level of national commitment to additional grain production, alcohol plant capacity and disposition of plant by-products. An example case calculated to supply 10 percent of the 1971 motor gasoline demand with ethyl alcohol would be produced from the grain grown on 100 million acres. A total of about 360 million acres was being cultivated in 1971.

The above-mentioned potentials for utilization of the primary energy resources available through agriculture are discussed in the following sections.

FORESTS AND WOODLANDS

About 25 percent of all U.S. land is now classified as forest and woodland. This includes parks, wildlife refuges and recreational areas. A century ago, wood supplied about 70 percent of all U.S. industrial energy. Today, it supplies less than 2 percent. However, on a total energy basis, this is a reduction of about 50 percent.

The capability of U.S. forests to meet future needs for lumber, for paper pulp and for paperboard is now questionable. In the past two decades, domestic and export requirements have increased an average of 3.9 percent annually, and this rate is predicted to increase. The approximately 50 million tons of U.S. pulp now produced annually is expected to double by 1985. Extension of the wood supplies through increased recycling of waste paper; utilization of tree limbs, wood bark, sawdust and other by-products; increased growth rates by fertilization; use of better yielding species of trees; more efficient forest management; and increased yields of end-products per unit of raw material may delay the time of serious shortages. However, shortages are predicted before the end of this century. Even if the supplies can be collected and transported, they will be used for paper and board which result in a higher financial return.

Wood supplies in the United States offer only minor potentials for additional industrial energy, and wood cannot be considered an important raw material in the long-range future U.S. industrial energy requirements.

AGRICULTURAL RESIDUES AND BY-PRODUCTS

The total dry weight of agriculture residues and by-products in the United States is reported by the Department of Agriculture as 523 million tons per year, excluding Hawaii, located as shown in Figure 7. This is an aggregate, consisting principally of 141 million tons of cereal straws (Figure 8), 55 million tons of corncobs, nutshells and fruitpits (Figure 9) and 325 million tons (dry basis) of animal wastes (Figure 10).

Use of Agricultural Residues as Primary Fuels

The weight of collectable agricultural residues such as straws and shells, hulls, corncobs and similar materials from present U.S. agricultural production is large, amounting to over 196 million tons annually. The heat equivalent of these residues would be on the order of 3,000 trillion BTU's.

These residues are now located throughout all 50 states, but the following estimates are based on the contiguous 48. No significant quantities of residues are now in collected form. Collection costs and delivery to regional power plant locations would normally vary from around $10 to about $15 per ton. Heating values of the residues are on the order of 8,000 BTU's per pound, or about 60 percent of the heating value of bituminous coal. Thus, the 1970 cost of collection alone would run from about $0.60 to $1.00 per million BTU's.

Agricultural residues are a potential source of large amounts of energy but could not now compete economically with such fossil fuels as coal and oil except under very favorable circumstances.

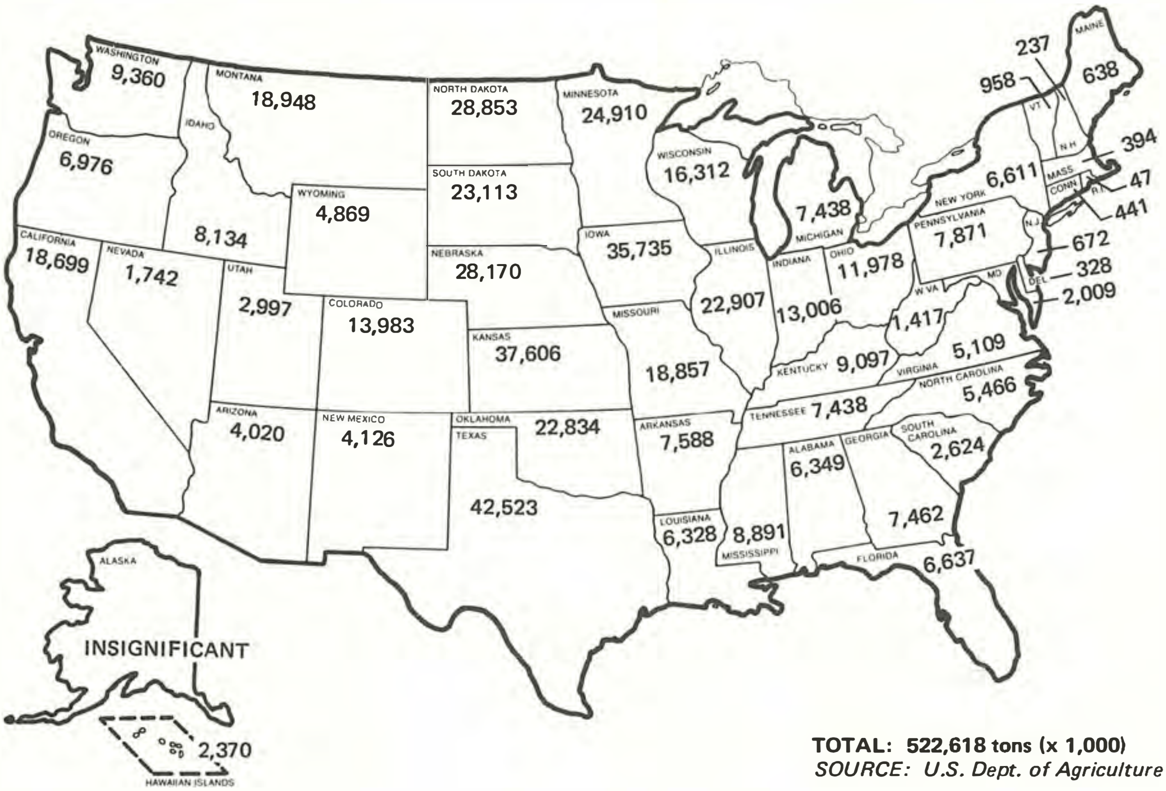


Figure 7. Agriculture: U.S. Industrial Energy Materials, Residues and By-Products, Quantities and Locations.

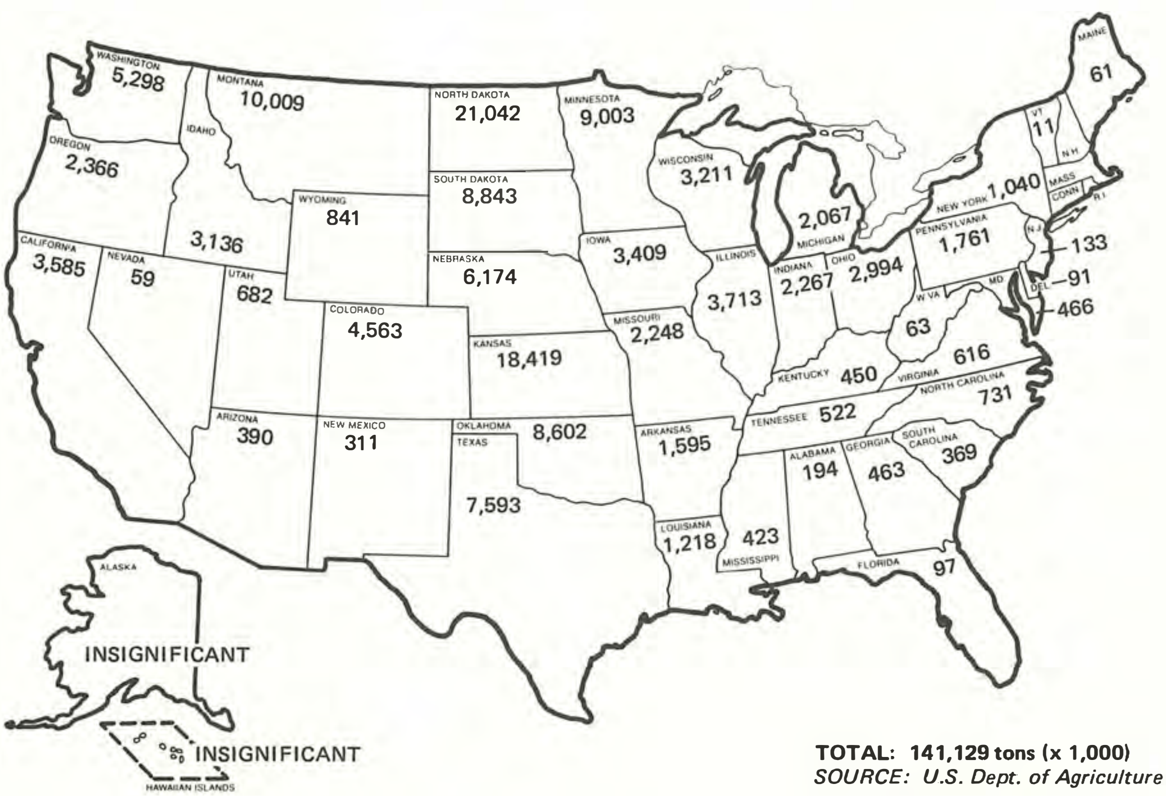


Figure 8. Agriculture: U.S. Industrial Energy Materials, Cereal Straws (Wheat, Rye, Rice, Oats, Barley), Quantities and Locations.

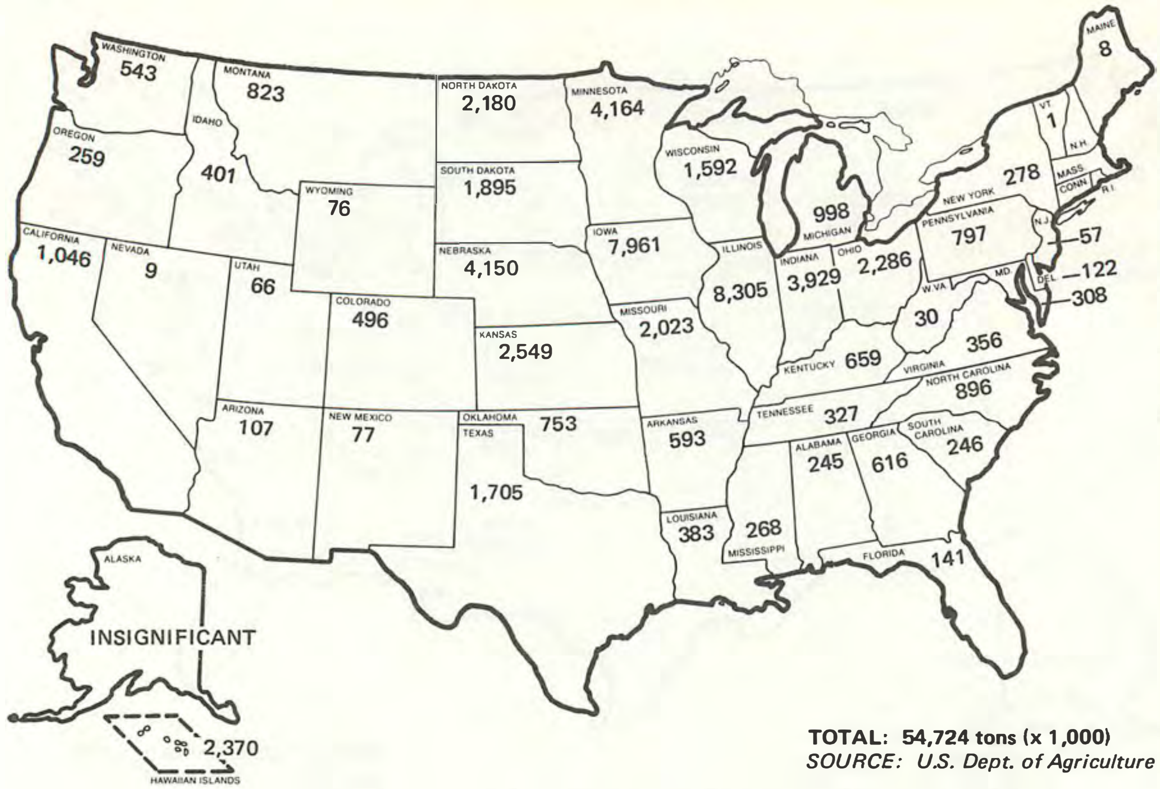


Figure 9. Agriculture: U.S. Industrial Energy Materials, Corncobs, Nutshells and Fruit Pits, Quantities and Locations.

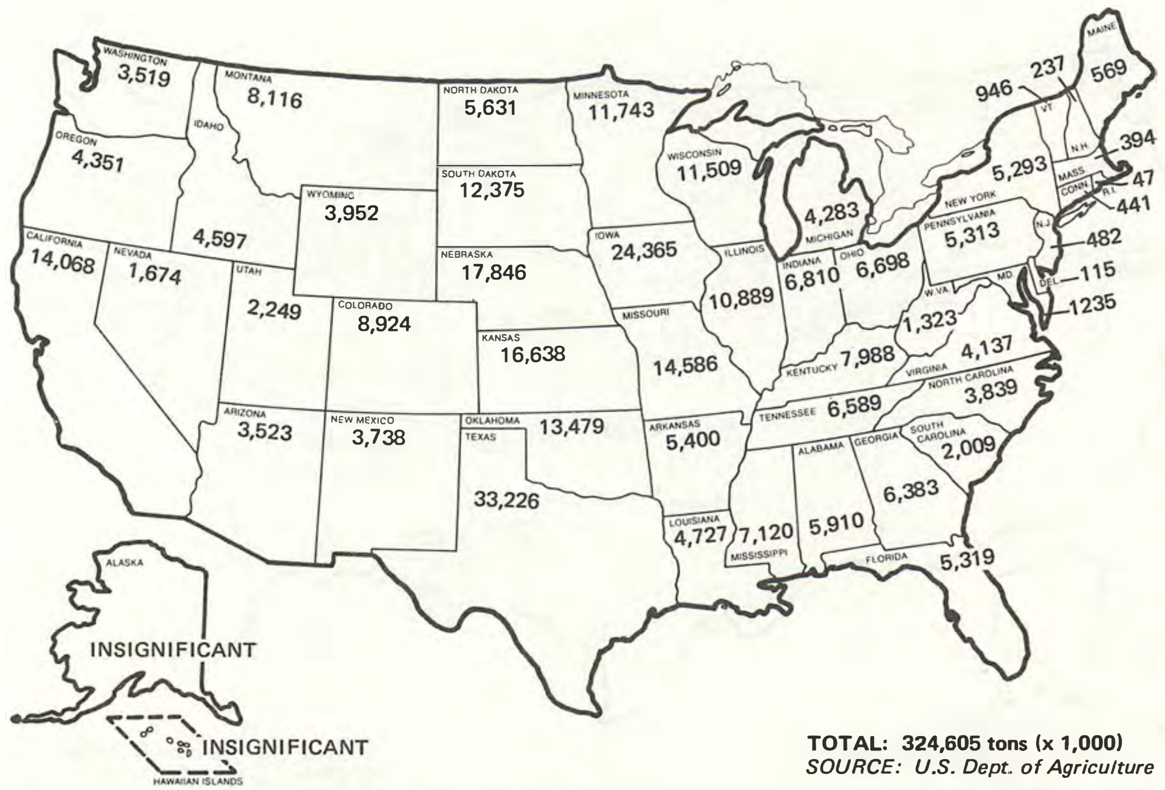


Figure 10. Agriculture: U.S. Industrial Energy Materials, Animal Wastes--Fecal and Processing (Dry Basis)--Quantities and Locations.

Collection facilities and the power plants for significant usage do not presently exist.

ANIMAL WASTES

Domestic animal wastes in the United States currently total about 2.03 billion tons per year--about 325 million tons of dry matter (Figure 10)--and are increasing with population and economic growth. Disposal of these wastes is a serious economic and environmental problem. Many research studies are in progress, but economically overall acceptable solutions have not been resolved. However, such quantities of organic wastes could be a significant factor in future long-range energy considerations. The total heat equivalent of these wastes after adjusting for water evaporation would be on the order of 1,600 trillion BTU's per year.

CONVERSION TO GAS OF AGRICULTURAL RESIDUES AND BY-PRODUCTS AND ANIMAL WASTES

Potentially, agricultural residues, fiber crops and animal wastes could be converted into gases for fuel or for chemical synthesis. These gases could be produced through fermentation or through pyrolysis of the wastes.

Fermentation of a ton of dry residue would yield approximately 10,000 cubic feet of gas having a heating value of about 500 BTU's per cubic feet. A raw material cost (1970) of $10 to $15 per ton would thus be equivalent to $1.00 to $1.50 per thousand cubic feet of gas with a heating value of 500 BTU's per cubic feet. Fermentation of the 520 million tons of residues (total U.S. agricultural wastes and by-products, excluding Alaska and Hawaii) could produce on the order of 2,600 trillion BTU's per year.

Pyrolysis of a ton of residue would yield on the order of 6,800 cubic feet of mixed gases with a net heating value of about 150 BTU's per cubic foot. A raw material cost of $10 to $15 per ton would thus be equivalent to $1.50 to $2.25 per thousand cubic feet of gas with a heating value of only 150,000 BTU's per thousand. The 520 million tons of residues could produce on the order of 530 trillion BTU's.

Neither the fermentation or pyrolysis procedures appear to be economically competitive with established fossil fuels as a source of large-scale industrial energy for the near future. However, removal of many of these wastes is a must for pollution control, and any financial return may be considered a profit. It is thus possible that disposal through fermentation may result in significant future contributions to the U.S. industrial energy supply.

CULTIVATED CROPS

About 360 million acres, or 16 percent of all U.S. land (2,260 million acres), are now used for cultivated crops. This is about 60 percent of the land that might be used to some degree for this purpose. However, normally, the best yielding land for the various crops is cultivated.

Cereal grain production per acre for the past decade has varied, but on an average has increased over 3 percent annually. This increase has generally exceeded the growth rate of the U.S. population and export demands, and the amount of cultivatable land used has decreased in this period. Based on U.S. requirements for the predictable future, there is a potential source of industrial energy from crops that could be produced on these unused acres. Land lost to non-crop use could be significant in the long-range picture if diversion were to continue at the present rate. This loss is expected to total about 20 million acres by 1985. Fortunately, to date, most of the loss has been land not highly suitable for cultivated crops.

Use as Primary Fuels

The growing of crops specifically for primary burning fuels is a possibility. Yields of different fiber crops vary by several hundred percent. The probable maximum yield in selected U.S. regions is about 20 tons of dry matter per acre per year. With this yield, production costs per ton of dry matter (1970) would be in the order of $10. The heat of combustion per ton would be about 15 million BTU's. Thus, a ton of dry matter at $10 ($0.67 per million BTU's) would be equivalent to coal at about $17 per ton on a comparative BTU basis. U.S. land that could produce 20 tons of dry matter per acre is limited. Normal yields of 50 percent of this weight are more realistic, and increased yields are energy intensive.

Through research, the development of high-yielding new industrial energy crops that better utilize solar energy may be a possibility. A significant breakthrough could have a major impact on land usage, economics and agriculture's contribution to the industrial energy supply. This is not expected to occur before 1985.

Cereal Grain Conversion to Industrial (Ethyl) Alcohol

A logical sequence of energy conversions is to use the idle land to produce cereal grain, which is largely carbohydrate, and convert the carbohydrates by fermentation to ethyl alcohol--a convenient combustible fuel. The conversion to ethyl alcohol by fermentation is technically feasible, and ethyl alcohol is usable as a motor fuel. One hundred million of the unused acres with an average yield of 70 bushels of grain per acre (approximately 3,900 pounds) would be equivalent to about 80 billion gallons of alcohol--or about 20 percent of the some 90 billion gallons of motor fuel that were consumed in the United States in 1971. The energy equivalent of ethyl alcohol is about 12,000 BTU's per pound or 80,000 BTU's per gallon. (For gasoline, it is approximately 135,000 BTU's per gallon.)

The cost of this ethyl alcohol would currently be higher than present petroleum motor fuel costs. However, when evaluated against balance of trade, assistance to many U.S. regional economies, improved air pollution control and engine performance, fermentation alcohol must be considered in future industrial energy studies.

The conversion of starch and sugars to ethyl alcohol is shown in Figure 11.

$$\underset{\textit{Starch}}{(C_6H_{10}O_5)_n} + nH_2O = \underset{\textit{Dextrose}}{nC_6H_{12}O_6}$$

$$\underset{\textit{Maltose}}{C_{12}H_{22}O_{11}} + H_2O \longrightarrow 2\ \underset{\textit{Dextrose}}{C_6H_{12}O_6}$$

$$\underset{\textit{Dextrose}}{C_6H_{12}O_6} \longrightarrow 2\ \underset{\textit{Ethyl Alcohol}}{C_2H_5OH} + 2\ \underset{\textit{Carbon Dioxide}}{CO_2}$$

Figure 11. Conversion of Starch and Sugars into Ethyl Alcohol.

The theoretical yield of alcohol from starch is 0.568 pounds per pound of starch. Theoretically, 180 pounds of dextrose should yield 92 pounds of alcohol. In actual practice, yields generally are about 90 to 95 percent of theoretical.

Alcohol production is directly related to the starch in the grain. If, as shown in Table 22, the respective starch content of hard wheat, soft wheat and corn is 64, 69 and 72 percent (moisture-free), respectively, the maximum alcohol that could be

TABLE 22

AVERAGE PERCENTAGE COMPOSITION OF CEREAL GRAINS*

Grain	Starch	Protein	Oil	Fiber	Other Constituents†
Hard Wheat	64	14	2	2	18
Soft Wheat	69	10	2	2	17
Dent Corn	72	10	5	2	11
Sorghum	71	13	3	2	11

* Moisture-free basis.

† Minerals, sugars, pentosans and vitamins.

produced from a bushel (wheat--60 pounds and corn--56 pounds) would be 21.8, 23.5 and 22.9 pounds. Translated to a 14-percent moisture basis and a practical 90-percent yield of alcohol, the anhydrous alcohol obtained per bushel would be 16.9, 18.2 and 17.8 pounds, respectively, or 2.58, 2.75 and 2.71 gallons.

The cost of ethyl alcohol from wheat and corn depends on many conditions, such as location, regional labor rates and type of wheat used. Past studies have shown that a practical-size grain fermentation plant could process about 20,000 bushels per day. Such a plant at current prices would cost about $14.0 million to construct. Anhydrous alcohol production would be about 17.5 million gallons from 6.6 million bushels of grain. Representative cost estimates are shown in Table 23 for wheat and Table 25 for corn.

The grain cost per gallon of alcohol would depend directly on the grain price as shown in Tables 24 and 26.

Ethyl alcohol has been used as a component in U.S. motor fuels on a limited scale. Alcohol will give acceptable blend and handling performance, provided the blend contains at least 10-percent (by volume) anhydrous alcohol. Lower blends might also be used with dual and more expensive fuel systems. The basic problem has been unfavorable economics.

It would require about 3.4 billion bushels of cereal grains annually to produce the 9.0 billion gallons of anhydrous alcohol (10-percent blend). (The 1971 cereal production of wheat, corn and sorghum was approximately 1.6, 5.5 and 0.9 billion bushels, respectively.) This alcohol would cost more than $4 billion to produce from grain costing $1 per bushel. Approximately 500 fermentation plants with a total capital investment on the order of $7.0 billion would be required. (Present total installed plant capacity is 15 to 20 million bushels.) About 28 million tons per year of by-product feed would be produced.

The significant effects of this 28 million tons of by-product feed on the markets for other grains and cereals have not been evaluated. These high-protein by-product feeds would not fill the gap left by removal of a high proportion of feed grain from the market. These by-product feeds would also compete with such materials as soybean meal, cottonseed meal and other feed protein concentrates. Basically, there could be an excess of protein feeds but not enough carbohydrate energy.

TABLE 23

FERMENTATIVE CONVERSION COST OF 190° AND 200° PROOF ALCOHOL FROM WHEAT
(Exclusive of Cost of Wheat)

	Cost/Gallon* (Cents)
190° Proof, Alcohol (2.72 Gallons/Bushel)	
Base Conversion Cost	34.1
Depreciation ($1.45 million/year, 10 years, 17.2 million gallons)	8.5
Total	**42.6**
By-Product Feed Credit (6.5 lb/gal. alc. at $100/ton)	32.5
Net	**10.1**
200° Proof, Alcohol (2.6 Gallons/Bushel)	
Alcohol (1.048 gal. at 10.1¢)	10.6
Cost of Dehydration	2.4
Total Cost, Exclusive of Wheat, Profit, Packaging and Sales Expenses	**13.0**

* All costs are expressed in constant 1970 dollars.

Source: Dwight L. Miller, "Fuel Alcohol from Wheat," National Wheat Utilization Conference, November 3, 1971; updated to May 1973.

TABLE 24

EFFECT OF WHEAT COST ON ETHYL ALCOHOL COST
(Basis: 2.6 Gal. 200° Proof Alcohol/Bushel)

Wheat Price/Bushel (Dollars)	Alcohol Cost/Gallon, (Cents)		
	Wheat	Conversion*	Total Base Cost†
1.00	38.5	13.0	51.5
1.25	48.0	13.0	61.0
1.50	57.7	13.0	70.7
2.00	77.0	13.0	90.0
2.50	96.3	13.0	109.3

* Conversion costs are constant 1970 dollars.

† These costs do not include profits, packaging and sales expenses.

Source: Dwight L. Miller, "Fuel Alcohol from Wheat," National Wheat Utilization Conference, November 3, 1971; updated to May 1973.

TABLE 25

FERMENTATIVE CONVERSION COST OF 190° AND 200° PROOF ETHYL ALCOHOL FROM CORN

(Exclusive of Cost of Corn)

	Cost/Gallon* (Cents)
190° Proof, Alcohol (2.82 Gallons/Bushel)	
Base Conversion Cost	33.2
Depreciation ($1.45 million/year, 10 years, 17.7 million gallons)	8.2
Total	41.4
By-Product Feed Credit (6.8 lb/gal. alc. at $60/ton)	34.0
Net	7.4
200° Proof, Alcohol (2.7 Gallons/Bushel)	
Alcohol (1.048 gal. at 7.4¢)	7.8
Cost of Dehydration	2.4
Total Cost, Exclusive of Corn, Profit, Packaging and Sales Expenses	10.2

* Costs are in constant 1970 dollars.

Source: Dwight L. Miller, "Corn and Its Uses," National Corn Growers Association, April 5, 1972; updated to May 1973.

TABLE 26

EFFECT OF CORN COST ON ETHYL ALCOHOL COST

(Basis: 2.7 Gal. 200° Proof Alcohol/Bushel)

Corn Price/Bushel (Dollars)	Alcohol Cost/Gallon, (Cents) Corn	Conversion	Total Base Cost*
1.00	37.0	10.2	47.2
1.25	46.3	10.2	56.5
1.50	55.5	10.2	65.7
1.75	64.8	10.2	75.0
2.00	74.0	10.2	84.2

* These costs do not include profits, packaging and sales expenses.

Source: Dwight L. Miller, "Corn and Its Uses," National Corn Growers Association, April 5, 1972; updated to May 1973.

Chapter Five

SOLAR ENERGY

SUMMARY

Agriculture represents a special case of indirect solar energy conversion. Other possibilities exist for the direct and indirect use of solar energy. However, as long as fossil fuels remain abundant worldwide, even at substantially higher prices, the utilization of solar energy will be confined to small experimental installations and unique situations.

Because it is so diffuse and intermittent when it reaches the earth, solar energy can be put to no foreseeable large-scale use over the next 15 years, even with appreciable improvements in technology.

The large area over which solar energy must be collected and the cost of the collection and conversion equipment prevent the widespread use of such devices as solar evaporators, solar desalinators, solar heaters, solar cookers, solar furnaces, solar cells, solar houses, etc. Another factor which discourages the use of solar energy is that fossil fuels are available to do the same job night and day without cloud interference.

The silicon cell, developed about 15 years ago, has proved to be a reliable means for direct conversion of solar radiation to electricity for applications in outer space. The generation of a significant amount of power, however, requires the connection of an extremely large number of cells. The high capital cost of silicon cell arrays results in power costs on the order of $2 to $5 per KWH. Thus, the cost is about 1,000 times that of conventional power sources.

Based on current research levels on solar energy cells, no breakthrough is anticipated before 1985. The time when this ultimate source of energy will have to be used to supplement the dwindling supplies of other sources remains indefinite but could be as soon as the year 2000. When this time comes, solar energy will have to be used not only to produce power and heat but also, with the aid of chemistry and other resources, to produce the fuels and lubricants for mobile equipment, as well as rubber, plastics and other essential petrochemicals. Such conversion can be achieved with the aid of the hydrogenation of carbon monoxide, but attainment of this goal will require several years of sophisticated research and development.

A greater recognition by government of the ultimate need for solar energy could occur in the next 15 years. If the use of solar energy utilization is ever to achieve any prominence in the United States, it would appear that its development must be supported by government just as atomic energy was.

DISCUSSION

Had it not been for the abundance of fossil fuels--coal, oil and natural gas-- we might today have a *solar energy economy* just as effective and efficient as our *fossil fuel economy.* If need had forced man to devote the phenomenal ingenuity and inventiveness which he has displayed in the past 150 years to the development of devices for the utilization of solar energy instead of fossil fuels, we might today have huge solar energy plants and complexes, similar to our oil refinery and chemical complexes, where the sun's energy would be collected, concentrated and stored to produce not only electric power but a whole host of other things.

In these complexes the technology of producing hydrogen and carbon monoxide from water and air and from plants and other carbon-containing resources would have been perfected, and through the hydrogenation of the carbon monoxide--a process that is already well known--we would be producing hydrocarbons (synthetic crude oil and gaseous mixtures) from which we could derive the same petrochemicals and the same lubricants and fuels for mobile equipment that we produce today.

Because these solar complexes would have to be located in the hot sunny areas of the world--deserts and the like--we might have learned to transmit electrical energy over long distances more effectively, without wires,perhaps.

We would have improved the heat pump to supplement the sun for the heating and air conditioning of houses and buildings, and we would undoubtedly have continued the improvement of solar cells and thermoelectric and thermionic devices for the direct conversion of solar energy to electricity. Also, with improvements in the methods and cost of producing, storing and transporting hydrogen and oxygen, we might be using fuel cells in the homes.

We most assuredly would have done a lot more on the study of photochemical reactions in which may lie the solution to the problem of storing solar energy.

Availability of Solar Energy

There is plenty of solar energy available to meet all our needs. All of the energy that was consumed in the United States in 1970 (about 68 x 10^{15} BTU's) could have been collected from the sun by a single collector only 27 miles in diameter (570 square miles in area)[5] *providing* that collector was a satellite *above* the earth's atmosphere and so situated that it was exposed *normal to the sun's rays all of the time.* Under these circumstances, the collector would receive 430.5 BTU's per hour per square foot which is known as the *solar constant.*

The earth's surface, however, is not exposed normal to the sun's rays all the time, and it is surrounded by an atmosphere.

Thus, by the time the sun's energy reaches the earth's surface it is so diffuse and intermittent that it is difficult to regather it to put it to useful work.

About half of the sun's energy is absorbed or reflected (scattered) back to space by the clouds and the atoms and molecules of the atmosphere.[4] The rest is received intermittently, from sunrise to sunset, which varies in duration from place to place and season to season. Most of the time the sun is concealed and there is no solar energy at all.

The figure usually used for the solar energy received by a horizontal surface on an "average day the year round" between the 40th parallels of the earth, which encompasses the southern half of the United States, is 1,500 BTU's per square foot per day.[13] This corresponds to 62.5 BTU's per hour per square foot, which is 14.5 percent (one-seventh) of the solar constant.

Present Uses of Solar Energy

What happens to the energy that does reach the surface? Some of it is reflected back to space; part of it promotes the growth of vegetation through photosynthesis; and the rest makes the receiving surfaces a few to several degrees hotter than the surrounding atmoshpere.

This surface heating effect can be increased by painting the surfaces black to reduce reflections and further increased by covering the surface with a transparent sheet of glass or plastic which lets the solar wavelengths through but prevents the longer reflected wavelengths from passing out. This is the *hothouse* or *greenhouse* effect.

Solar Collectors

Solar collectors embodying both of these features are used to promote the growth of plants, to heat water and houses and to distill water.

Such systems can only generate heat at relatively low temperatures--150 to 160°F too low for conventional power generation purposes--and even the most simple collectors are expensive (about $4 per square foot).

Thus, a 500 to 1,000 square foot collector on the roof and south side of a solar house might cost $2,000 to $4,000, to which has to be added another $1,000 or so to provide for the energy storage that is required to provide for the time when the sun isn't shining. A simple storage system may consist of a tank to store the solar-heated water with the tank surrounded by rocks enclosed in a sealed and insulated enclosure in the basement using an air circulating system to transport the heat from the tank enclosure to the various rooms of the house.

Initial costs such as this ($3,000 to $5,000) can be recovered in fuel savings over a period of years, but such costs coupled with the nuisance of the operation and maintenance of the solar system are difficult to justify, especially in climates where a supplementary fuel-fired system has to be installed anyway.

The use of collectors of this type to distill and desalinate water can only be justified in places where the demand for water is so small and the land area so cheap that a fuel-fired plant cannot be justified.

Solar Furnaces

To obtain temperatures high enough to boil water, to make steam or to cook, lenses or solar reflectors have to be used to concentrate the energy. With such devices equipped with movements to follow the sun, extremely high temperatures can be obtained--hot enough to melt rocks and refractories.

Power Generation

Much work needs to be done to improve the absorption and concentration of solar energy to increase collector working temperatures to the point where collectors can be used to generate steam for power generatiom purposes.

The use of solar cells to generate power in space is well established but in that case, *need* was the paramount consideration and cost secondary. The cost of solar cell arrays for space purposes is now about $300,000 per kilowatt with a power output in space of about 10 watts per square foot of panel area with the panels following the sun automatically. (This is equivalent to 34.12 BTU's per hour per square foot, which is about 8 percent of the solar constant.)

On earth, in a horizontal position on an "average day the year round," the cell output is about one-tenth of that in space, i.e., one watt per square foot. If mass production were to set in, the experts believe that the cost of the cell arrays might be reduced by one-third to $100 per square foot, and with improvements in cells and cell arrangements it is felt that the ouput might ultimately be increased by 50 percent, resulting in a yield of approximately 1.5 watts per square foot on an average day the year round.

Using these figures as a basis, one can rough out that one square mile of solar cell arrays (28 million square feet) would have a capacity of 42 MW and might be built with an investment of arround $3 billion. This is about $70,000 per KW compared to $150 to $200 per KW for fossil-fuel plants and $250 to $300 per KW for nuclear plants.

Need for Research

The large amount of capital investment involved in energy collection and storage systems and the large amount of land area involved constitute the reasons why solar energy has not been able to compete with our convenient and abundant fossil fuels. Had we really needed this energy, however, it is quite likely that the technology would have been developed to improve these economics materially.

As it is, the amount of research that has been done in the solar energy field has been relatively small, and for the most part the devices that have been worked on have been obvious and relatively crude. It takes little imagination to use magnifying glasses and mirrors to concentrate and focus the sun's rays or to use ponds of water covered with glass or plastic sheets (the greenhouse effect) to collect solar energy to heat water or to evaporate it.

These, however, are the kinds of things that have been worked on. Small solar cookers (parabolic or cylindrical mirror concentrators) are sold commercially in India and elsewhere, and a large number of fairly large solar water heaters and solar stills (water desalters) have been built in Japan, Africa, Australia, Israel and many of the Mediterranean nations. High-temperature solar furnaces have been built and there are several experimental solar-heated houses in existence. These devices are all described in considerable detail in the solar energy literature. The best reviews of these developments are listed in the bibliography.[1, 2, 14, 15, 16] In this field, there has been nothing new for several years.

Nature of Solar Energy

A certain amount of sophistication has been displayed in the selection and preparation of certain collector surfaces that are "selective to certain wavelengths," but except for this and for a small amount of work on photosynthesis and other photochemical reactions, solar cells are really the only development that recognizes solar radiation for what it really is--a spectrum of quanta or photons each with certain specific properties.

Quanta are individual, discrete packages of energy which are emitted when one of the electrons surrounding the nucleus of an atom jumps from one position or orbit to another of lower energy level. Each atom has its own unique electron configuration, and therefore each has its own unique series of quantum jumps. The kind of photons that an atom or substance emits (or absorbs) are unique for that atom and thus can be used to identify the nature of that material.

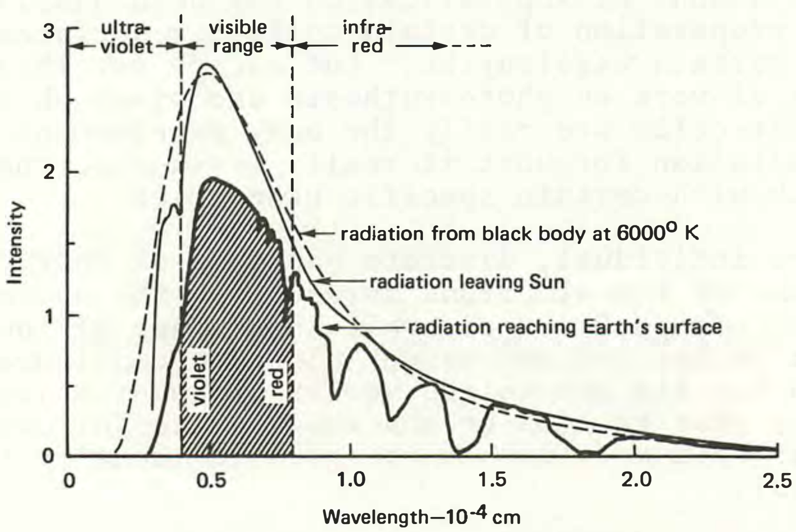
When a black (non-reflective) body is exposed to solar energy the motion of its molecules is increased, that is, its temperature rises. This is heat. In addition, certain atoms or molecules in that body may absorb certain quanta from the incident ray in which event the atoms involved may become activated to the point where they will react in a photochemical reaction like plant photosynthesis. In some cases, the absorption of a photon may cause an electron to leave the atom, in which case the atom is left with a positive charge (ionized). This process is the one that is involved in solar cells, photocells and other photoelectric phenomena.

Photons travel at the speed of light (186,000 miles per second) until they are intercepted or absorbed by atoms and molecules of the air or space or until they are reflected or absorbed by solid surfaces. Because these quanta exhibit wave properties (wavelength and frequency) they can be separated from each other as they are passed through prisms, water or other refracting media.

Solar Spectrum

When the sun's rays are passed through a prism or through water droplets in the sky, the sunlight that we normally perceive as white becomes separated into a rainbow or spectrum of colors. That is, each quantum or photon is bent or refracted differently as it passes through the prism, and those that appear red to our eyes (those of higher wavelength and of lower energy and frequency) are bunched together at one end of the spectrum while those that appear violet (those of shorter wavelength and higher energy) are bunched together at the other end with blue and green in between.

The solar spectrum, as shown in Figure 12, ranges from the ultraviolet through the visible range into the infrared. Most of the photons are within the visible range, predominantly green and red.



(After Abbott and Langley.)

Figure 12. Solar Spectrum.

The intensity of light or of any color is dependent upon the number of quanta of that particular wavelength or frequency that is involved. Our eyes are only a rough measure of intensity. This is an extremely small amount of energy because 100 quanta of visible light amount to only about 3×10^{-17} joule (less than 3×10^{-20} BTU's).

In Figure 12, the heavy solid line represents the quanta distribution in the sun's rays as they reach the earth, after part of the quanta have been absorbed by certain molecules as the ray or beam passed through the atmosphere. The smoother and lighter solid line above it represents the solar spectrum above the atmosphere. The dotted line represents the spectrum that one received from any body that has been heated to 6,000°K (10,000°F). It is because these two upper lines are so similar that the sun is said to radiate like a body at 10,000°F.

Our eyes can differentiate between the various colors because certain substances in the retinal react to one type of quantum (one color) and not to the others. This is true also of other photochemical reactions as in color photography and color television tubes. The fact that certain quanta are absorbed by certain atoms and not by others serves as the basis for the whole science of spectroscopy through which various substances can be identified by simply noting which quanta or photons they absorb (or emit) and which they do not.

Solar Cells

With some substances, certain quanta can cause electrons to jump completely out of orbit--that it, to free themselves. The alkali metals lithium, sodium, potassium, rubidium and cesium are especially effective emitters, with cesium serving particularly well with quanta in the visible range. This phenomenon, called photoelectric effect, is that involved in the operation of photocells and solar cells which can convert light and other radiation directly into electricity.

When certain quanta strike a cesium-coated surface (usually placed in a vacuum tube) electrons are released from the surface. These can be collected, thus creating an electric current through an external circuit connecting the collector back to the coated surface.

A current can also be produced in this same manner, as shown in Figure 13, between a thin layer of semitransparent, light-sensitive material deposited on a solid base, such as selenium on iron or cuprous oxide on copper and others. These are the photoelectric cells that are used to measure light intensity in photography.

In the solar cells the active ingredients are incorporated into the body of the cell material. The solar cell consists of a sandwich of very pure semi-conductor material, such as silicon,

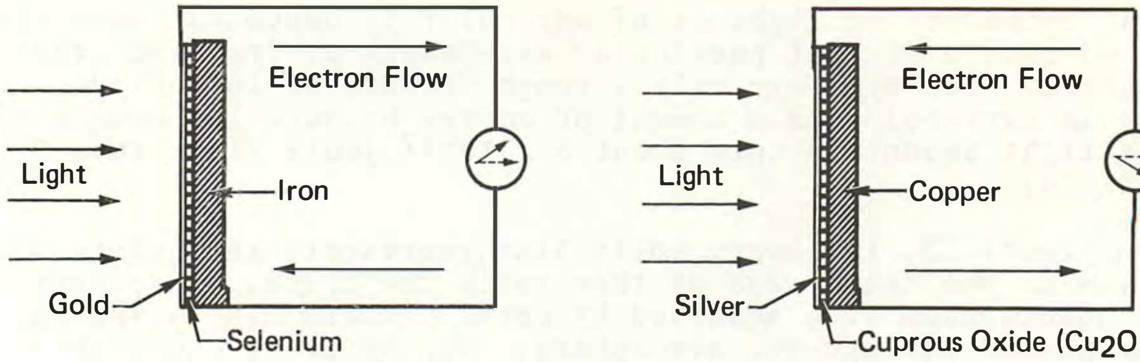


Figure 13. Photoelectric Cell

with one face doped with a few atoms of an electron donor, such as arsenic, and the other face doped with an electron acceptor, such as boron. When the sun shines on one of the faces, electrons that are released migrate through the junction of the two layers thus creating a potential and a current flow through an external circuit connecting the two faces.

Many combinations of semiconductor and doping materials have been tried, but so far the efficiency of these cells is still quite low, and a great many of them must be connected together to produce currents of practical magnitude. Because the semiconductor materials must be very pure, these cells are very expensive, and they have thus far been used only in space applications (to charge batteries) where cost considerations are secondary.

Need for Sophisticated Research

It is essential that such esoteric work as that done on solar cells recognize the more sophisticated nature of solar radiation and be accomplished if we are ever to find the key to unlock this vast supply of energy for future use. An extensive amount of work would be required to develop materials, surfaces and chemicals that would react to more of the quanta that are contained in the solar spectrum instead of to just a few.

In addition, serious consideration should be given to the work required to develop a satellite system to collect and concentrate solar energy which can then be transmitted to earth in concentrated beams of selected wavelengths to minimize diffusion and masking by the atmosphere. This idea was suggested in 1965[5], and it has since been expanded upon and shown to be feasible, even with present technology.[7] [11] A great deal of research and development work would have to precede such a scheme before it could be considered practical.

Work such as this can result only from long-range, visionary planning.

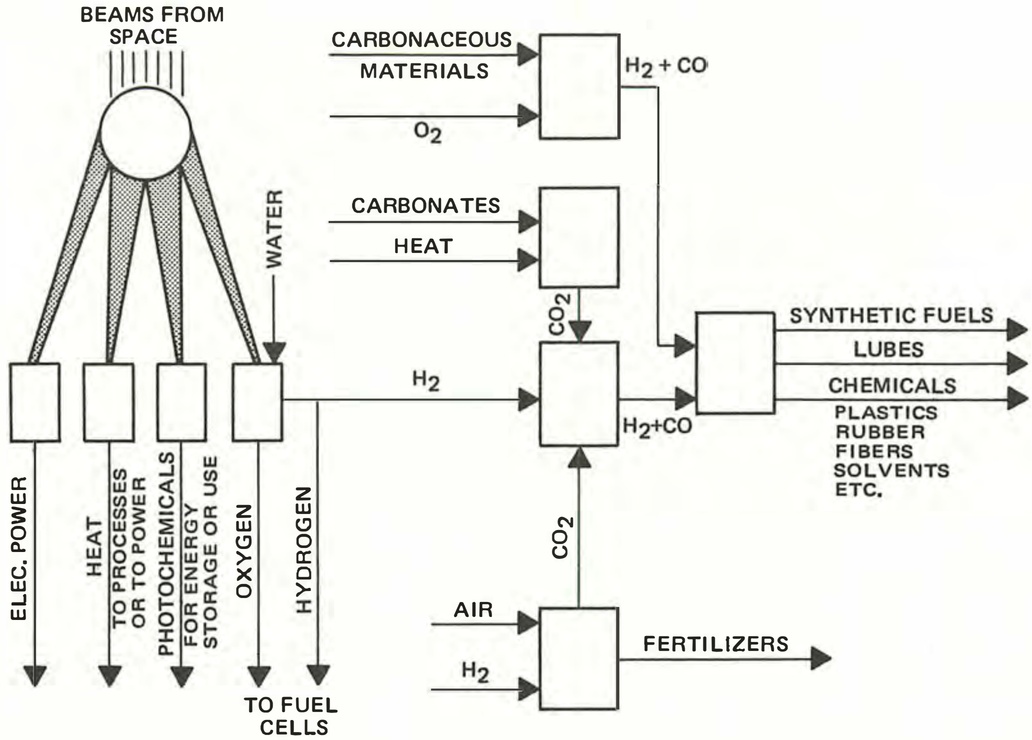


Figure 14. Solar Energy Complex.

Solar Complex

Figure 14 shows the kind of solar energy complex that we might someday end up with. In this plant, concentrated solar beams (or, better yet, microwaves of selected wavelengths) received continuously from a series of satellites are separated into various groups of quanta, each of which, after further concentration, is directed to the process where it will do the most good--one to the photoelectric plant to be converted directly to electric power, another to a photochemical plant for the production of chemicals to store energy or for other uses, one to solar furnaces or solar ponds to produce heat for processing purposes or for power generation, and others for more specific purposes such as the dissociation of water (with the aid of a catalyst not yet discovered) to produce hydrogen and oxygen which can be used as fuel for fuel cells or as raw materials for the manufacture of fertilizers, synthetic hydrocarbon fuels, lubes and chemicals such as rubber, plastics, fibers and solvents.

Need for Solar Energy

We cannot afford to wait too long to pursue the kind of work that is needed to make solar energy practical because, as shown in Figure 3, the demand for energy in the future will continue to grow,[6] and not long from now we are almost sure to need solar energy to help fulfill these requirements.

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Chapter Six

TIDAL ENERGY

The use of the energy in tides to generate power goes back at least to the 11th century when small tidal mills were used to grind corn in several European countries. In 1734, at Slades Mills in Chelsea, Massachusetts, a tidal installation developing 50 horsepower was used for grinding spices. On Passamaquoddy Bay in Maine, tidal mills were in operation prior to 1800.

For the past several decades, enthusiasts of tidal power have studied various projects in the United States, Canada and Alaska. Phrases such as "relentless," "powerful and unchanging" and "massive, untapped energy potential," although poetic and descriptive, fail to provide any sense of the available quantity of energy and the practicality of its exploitation.

A fundamental problem with tides is that the range (distance between high and low water levels) varies widely along the U.S. coast. From Eastport, Maine, the tidal range decreases from about 18 feet to 9 feet at the north shore of Cape Cod. South of Cape Cod, the tidal range is only 4 feet, and this diminishes to about 2 feet off the coast of Florida. A notable exception to the East Coast trend is the approximate 7-foot tidal range in Long Island Sound. On the Gulf Coast, the range is less than 2 feet. For the West Coast, the tidal range increases from about 4 feet at San Diego to about 11 feet at Seattle, Washington. Along the Canadian Coast, the range is about 12 feet, while the Cook Inlet in Alaska experiences about an 18-foot variance. Thus, except for specific bays in Maine and Alaska, the tidal range is too low to be practically useful.

The importance of tidal range in influencing the practicality and economics of tidal power can be best visualized through mathematics.

The incremental amount of energy per cycle which can be obtained from tidal flow of water depends on the following equation:

$$dE = gR\ (D.S.dR)$$

where R is the tidal range in feet, D is the water density, g the acceleration of gravity, and S is the area of the enclosed basin. Integration of the total tidal range, assuming S is independent of R, would lead to--

$$E = D.g.S\ \frac{R^2}{2}$$

If power is generated when the enclosed basin both fills and empties with water (double effect), the maximum energy would be given by--

$$E_{max} = D.g.R^2.S$$

The total annual (about 700 cycles) energy in KWH which can be generated in a single basin, double effect unit would be--

$$E_{(KWH/Year)} = 0.017.R^2.S$$

Available energy varies with the square of the tidal range and the first power of the enclosed or dammed tidal area. A 20-foot tidal range would require a barrage or dam enclosing only 25 percent of the area required for a 10-foot tidal range. For this reason, it is not practical to consider anything but large tidal ranges. The size of the required confined tidal bay increases, and the capital requirements for the dam and generators would also increase sharply. A location having a tidal range of 25 feet could theoretically generate about 10 KWH annually per square foot of surface. Thus, 10 billion KWH annually would require about 30 square miles of impounded water.

The basic pattern of tidal rise and fall can be changed by local conditions such as a river estuary, a peninsula or an offshore island. The outline and geography of a shoreline can concentrate tidal range to a level where it can be much larger. Certain bays and inlets which have a time characteristic matching that of the total ocean wavelength can have more dramatic tidal effects. Such a location occurs at the Bay of Fundy between New Brunswick and Nova Scotia. For example, at Yarmouth, Nova Scotia, near the entrance to the Bay of Fundy, a maximum tidal range of about 17 feet occurs. In the head of the bay near Cape Tenny and Economy Point, Nova Scotia, the maximum tidal range is as high as 50 feet. There is an amplification factor of about 3 because the length of the bay (185 miles) is approximately one-fourth the wavelength of the lunar semi-diurnal (twice-daily) component (740 miles).[5] This is the phenomenon of resonance and is similar in principle to that occurring in the motion of sound and electromagnetic waves.

On a yearly average, the tidal range at the head of the Bay of Fundy is about 35 feet. This range is significantly higher than elsewhere on the North American continent and has thus attracted most attention as a potential source of tidal power. In the United States, Passamaquoddy Bay, with a range of 18-24 feet, has also received much attention.

If 15 feet is assumed to be the lowest tidal range which might be developed in the next 30 years, then only the Passamaquoddy Bay region in Maine can qualify. Since this bay is bounded by Canada and Maine, development would necessarily be a joint venture. Actually, Passamaquoddy is a small bay which is a part of the larger Bay of Fundy. Table 27 summarizes estimates of energy potential which have been made for several areas.

The amount of energy that would be potentially available from the U.S. Passamaquoddy Bay is very low. Larger amounts of energy ranging from 13 billion KWH to perhaps as high as 50 billion KWH per year could be available from the Canadian Bay of Fundy. The large potential of 175 billion KWH is attractive but cannot practically be considered in the short-range.

TABLE 27

POTENTIAL TIDAL ENERGY

	Billion KWH/Yr.	Source
Passamaquoddy Bay, U.S./Canada—Selected Scheme	1.8	3
Cook Inlet, U.S.—Kustatan-Nikishka	75	6
Bay of Fundy, Canada		
3 Sites, Single Effect	13.4	7
3 Sites, Double Effect	16.8	7
Total Potential, Bay of Fundy	**175**	**1, 7**

The amount of potential tidal energy can be compared with the electrical requirements which have been forecast for the Canadian Maritime and the New England Census Division of the United States (Table 28).

TABLE 28

ELECTRICAL ENERGY REQUIREMENTS FOR CANADIAN MARITIME AND U.S. NEW ENGLAND DIVISION (Billion KWH)

	1970 Actual	1975	1980	1985	1990
Maritime Provinces Power Pool, Canada	7.0	10	15	23	31
New England, U.S.	58.3	80	110	152	210
Total	**65.3**	**90**	**125**	**175**	**241**

Source: J. G. Warnock and J. A. M. Wilson, "Acres Limited," paper delivered at International Conference on the Utilization of Tidal Power, Halifax, Nova Scotia, May 1970.

If the three sites in the Bay of Fundy which were extensively studied by the Atlantic Tidal Power Programming Board (ATPPB) are developed by 1985, 13 to 18 billion KWH would be available. Thus, these sites could supply about 9 percent of the projected electric power for the Canadian Maritime and New England by 1985.

Most of the schemes which have been proposed for tidal energy involve the generation of a peaking supply of power. This is consistent with the nature of tides. Power would be delivered in relatively large blocks, perhaps for only 1 to 2 hours per day. Relatively large capacity could be built into a tidal facility if it were only to operate at a 5- to 10-percent capacity factor in a peaking role. For example, two Bay of Fundy sites on Shepody Bay and Cumberland Basin could contribute a 5,000 MW block of power. The three sites identified in the ATPPB report have a potential capacity of 9,000 MW.[5]

Tidal installation could contribute a significant block of the total capacity for the Maritime Provinces and New England for the future. Table 29 summarizes a projection on the peak demand power for these areas.

TABLE 29

PEAK POWER DEMAND
(Megawatts)

	1970 Actual	1975	1980	1985	1990
Maritime Power Pool	1,307	2,200	2,700	4,100	5,500
New England	11,800	17,000	22,000	30,000	41,000
Total	13,107	19,200	24,700	34,100	46,500

Source: J. G. Warnock and J. A. M. Wilson, "Acres Limited," paper delivered at International Conference on the Utilization of Tidal Power, Halifax, Nova Scotia, May 1970.

As proposed in a recent paper,[4] tidal power could provide a 5,000 to 10,000 MW block of the 46,500 which might be needed by 1990. However, the total fraction of actual energy provided by the tidal facility would be much more modest. Realistically, a 10,000 MW block would only supply 5 to 12 percent of the required energy.

At present, the only operating tidal facility is in France. On the English Channel, the 90-mile-long Cotentin Peninsula forms a reflector for the incoming Atlantic tides. Deflection and resonance raises the water level to 44 feet in the Rance River. The French hydroelectric facility near St. Malo was built at a cost of $90 million and consists of 24 units totaling 240 MW. Plans exist to increase the capacity to about 320 MW. The cost of the French facility is about $350 per KW. The French system makes use of reversible turbines installed in locks.

In October 1969, ATPPB completed a report on the feasibility of tidal power for the Bay of Fundy. Twenty-three sites were examined, and three sites which appeared to offer the best possibilities were studied in considerable detail. It was found that the three sites in the Bay of Fundy could be developed to produce in excess of 13 billion KWH annually. A recent paper has stated that at least one of the sites on the Bay of Fundy could provide electrical energy at 5.6 mills per KWH. The particular scheme would involve 64 generating units with a total capacity of 2,176 MW at a capital cost of $474 million or $220 per KW. Some of the sites were costlier than this, presumably due to differences in tidal range, length of dam and water depths in the area. The Passamaquoddy project in Maine has been estimated to be about $1,000 per KW.

Accordingly, tidal power is higher in capital costs than other peaking devices such as thermal plants, pumped storage and gas turbines.

Many engineering problems would be involved in developing tidal power even in a relatively favorable area such as the Bay of Fundy. Small-scale development in the Cape Tenny and Cape Maringouin areas would encounter water depths of no more than 60 feet. Water depth near St. John would be up to 250 feet. At the mouth of the bay near Yarmouth, Nova Scotia, and Jonesport, Maine, water depths would be about 600 feet. Thus, plans to tap the ultimate potential of the Bay of Fundy and the Passamaquoddy area would have to cope with the larger scale problems of deeper water and the confinement of larger areas of the bay. However, engineering feasibility undoubtedly exists, given the necessary amount of capital.

Similar problems with water depth would occur near Alaska. While interior portions of the Cook Inlet are no more than 120 feet deep, the mouth of the inlet has depths of 300 feet. The remoteness of the Alaska area and the presence of drift ice and silt, together with a possibility of earthquakes, makes it unlikely that Alaskan tidal power will be developed in the next 20 years.

The practical potential for tidal power in the Northeast is probably no more than 30 to 50 billion KWH. The ultimate potential in the Passamaquoddy-Fundy area is several times this, but may not be practical to harness. The potential influence on ocean currents, weather and local fish-life cycles in the immediate area must also be considered. The magnitude of development, including a major portion of the Bay of Fundy, will require extensive and long-term engineering and oceanographic studies.

The potential for annual tidal energy is limited. Nonetheless, the summation of tidal energy over many years becomes significant. For example, the generation of 50 billion KWH annually at the Bay of Fundy would correspond to 240,000 barrels of oil per day, or about 2.6 billion barrels over a 30-year period. Thus, the costs for equivalent fuel oil over a 30-year period would be in the range of $7 to $10 billion. Capital costs for dams and equipment would perhaps be in the $4 to $7 billion range. Accordingly, the overall total cost for tidal energy appears somewhat lower.

Tides do provide a relentless, but limited, supply of potential energy. Realistically, if developed to the practical limit, tidal energy could provide only a small fraction of a percent (0.2 percent) of the energy required in the United States by the year 1985. As the energy requirements of Canada and the United States have grown, the significance of the tidal energy practically available in this country has been lessened.

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Chapter Seven

ENERGY FROM MUNICIPAL TRASH

Some 200 million tons of trash are collected yearly by towns and cities in the United States. The composition of this waste is shown in Table 30.

TABLE 30

COMPOSITION OF MUNICIPAL TRASH

	By Weight (Percent)
Paper, Paperboard	50
Iron and Steel	9
Aluminum	1
Glass, Ceramics, Rocks	10
Garbage, Yard Wastes	20
Plastics, Textiles, Misc.	10

From 75 to 80 percent of the cost of utilizing wastes lies in collection; only 25 percent of the costs arise from disposal. The reason for this is that a large fraction of municipal wastes are now simply placed in inexpensive landfills.

One simple approach to recovery of energy from wastes lies in incineration, with recovery of energy either as electric power or steam. A number of incinerators are in use in the United States, and other designs are being developed. The city of St. Louis has successfully utilized waste in their boilers to produce steam for electric power.

One of the most advanced designs for recovery of energy from wastes is the approach of the Combustion Power Company in San Diego. This development was financially backed by the Department of Health, Education and Welfare (HEW). Combustion Power design (CPU-400) will consume 400 tons per day of solid wastes. Refuse is first shredded, classified by air to separate metals and glass, and is finally dried and fed to a fluid bed combustion chamber. This design is similar to boilers which are under development for the combined cycle.

The CPU-400 design, using a gas turbine to drive electrical generators, obtains 15,000 KW of electric power and 82,300 pounds of steam per hour. This is a *total energy system* with an overall heat efficiency of about 75 percent.

The energy content of municipal trash is about 8 million BTU's per ton, making a total potential of 1,600 trillion BTU's per year if all 200 million tons of city and town trash in the

United States was collected for power generation. If the CPU-400 design is extrapolated to utilize all of the U.S. municipal trash, total electrical power generation would be 21,000 MW continuous, equivalent to 628 trillion BTU's per year. If average plant heat efficiency is 75 percent, total heat output would be 1,200 trillion BTU's per year with 572 trillion BTU's recovered as steam to heat buildings or factories. Total heat recovered represents about 1 percent of total U.S. energy demand for 1985.

Power generation of 15,000 KW for the CPU-400 design from 400 tons of trash per day represents a heat rate of less than 8,900 BTU's per KWH if the heat content of the trash is 8 million BTU's per ton. This is a very low heat rate for a conventional large steam plant.

It is of course impossible to collect and efficiently burn for power generation all 200 million tons per year of U.S. municipal trash. If this could be done, the 21,000 MW of electrical power would represent about 3 percent of the Federal Power Commission's 1970 projection for 1980 installed capacity.

As with agricultural and other waste materials, collection costs are quite high for municipal wastes. Since the material must be collected for whatever method is used for its disposal, these costs are not properly chargeable to the cost of recovered energy. The costs of metal separation and incineration are expected to be in the range of $5 to $15 per ton.

Assuming the energy content of trash is 8 million BTU's per ton, energy costs are from $0.60 to $2.50 per million BTU's. This will represent an attractive cost range as the cost of alternative fuels goes up. An increasing use of energy from municipal wastes is likely in the next few years. A significant fraction of the energy in wastes (about 65 percent) is that from the contained paper. If cellulosic fibers are recovered from paper, the energy in the wastes will be considerably reduced.

Part Three

Energy Conversion to Electric Power

Chapter Eight

COMBINED ELECTRIC GENERATION

BRAYTON-RANKINE COMBINED CYCLE

The utilization of gas turbines in combination with steam turbines is the technological innovation most likely to promote efficient use of fossil fuels in the generation of electricity. Combined-cycle (Brayton-Rankine) plants utilize the presently wasted hot exhaust from gas turbines to generate steam for conventional steam-electric generators. An additional increment of electricity is thus obtained with the same level of fuel consumption. This improvement in the efficiency of energy utilization in steam-electric plants is commonly expressed in terms of the heat rate. Changes in the national average of the heat rate will be slow due to the fact that so much installed capacity exists and that the ultimate replacement of current power plants and those on order through 1980 will not occur until well beyond the year 2000.

Combined-cycle plant capacity is likely to grow rapidly from zero in 1972 to about 90,000 MW in 1985 (see Table 31). By 1985, the combined-cycle could account for over one-third of the new fossil-fuel plant capacity.

Heat rate improvement in the gas turbine from 9,200 BTU's per KWH in 1972 to 7,000 BTU's per KWH in 1985 appears reasonable. A more rapid improvement in efficiency is assumed in the 1975-1980 period, presumably as new alloys, ceramics and cooling techniques are applied to gas turbines. Improvements would be slower in the 1980-1990 period, approaching a materials limit of about 7,000 BTU's per KWH in 1985.

TABLE 31

HEAT RATE TREND FOR CONVENTIONAL AND COMBINED-CYCLE FOSSIL-FUEL, STEAM-ELECTRIC PLANTS

	Annual Rankine Cycle Plant Additions* (MW)	Heat Rate Rankine Cycle (BTU/KWH)	Annual Brayton-Rankine Cycle Plant Additions* (MW)	Heat Rate Brayton-Rankine Cycle (BTU/KWH)	Annual New Fossil Plant Additions* (MW)
1972	22,000	9,800	0	9,200	22,000
1975	20,000	9,800	2,000	8,600	22,000
1980	15,000	9,600	8,000	7,300	23,000
1985	15,000	9,300	9,000	7,050	24,000
1990	15,000	9,000	10,000	7,000	25,000

* Annual new plant addition rates shown were assumed for the purpose of projecting limits of reduction in the national average heat rate for fossil-fuel steam plants.

The average heat rate of all fossil-fuel plants installed in 1972 was assumed to be 9,800 BTU's per KWH (based on 50 percent for coal at 9,000 BTU's per KWH, 30 percent for residual oil at 11,000 BTU's per KWH, and 20 percent for gas at 10,000 BTU's per KWH) and was assumed to stay constant for installed steam plants through 1977. The use of cooling towers and stack gas scrubbing for environmental protection purposes will tend to perpetuate relatively high heat rates.

After 1978, the heat rate of conventional Rankine cycle steam plants should begin to improve due to the introduction of higher pressure steam (about 1975) and the use of fluid-bed combustion for residual oil and coal boilers (about 1980). However, the use of residual oil containing sodium and vanadium will tend to keep the overall efficiency of the steam cycle low unless residual oil is gasified or used in fluid-bed boilers. Gasification technology could lead to more rapid improvements in the Rankine cycle.

Heat rate trends are shown in Figure 6. It has been assumed that fossil-fuel plant capacity of 300,000 MW existed in 1971, with a heat rate of 10,666 BTU's per KWH. The annual operating factor for this capacity was assumed to be 60 percent in 1972, decreasing to 40 percent in 1990 due to increased utilization of the newer, more efficient fossil-fuel and nuclear plants. The conventional Rankine cycle capacity added after 1972 was assumed to have an annual operating factor of 70 percent, as opposed to 50 percent for the combined cycle.

Based on these assumptions, the national heat rate will decrease from 10,666 BTU's per KWH in 1972 to 9,798 BTU's per KWH in 1985 and 9,057 BTU's per KWH in 1990. This represents an improvement in the overall efficiency of fossil-fuel plants of about 8 percent over the 13-year period.

The rate of installation of new fossil-fueled power plants shown in Table 31 and reflected in the trends in heat rates in Figure 6 was selected as a maximum rate for the purpose of analyzing the effect of improved energy conversion on the national average heat rate. The number of fossil plants may be less than that assumed, depending on such factors as the relative costs of fuels, required captial investment, and the lead times for construction and regulatory approval by government of various types of plants.

As shown in Figure 6, the average heat rate for the combined-cycle plants in 1990 would be about 7,300 BTU's per KWH. This is an optimistic schedule for the installed capacity and efficiency trends for combined-cycle plants. Despite the optimism, it is readily seen that the change in the national heat rate over an 18-year period is relatively small.

LOW-BTU GAS FROM COAL

Background

Low-BTU gas does not have a very precise definition. In the context of this report, it is considered to be the gas resulting from reacting coal with air and steam. Low-BTU gas is unlike high-BTU gas or conventional natural (or pipeline) gas in that it contains a low concentration of methane, and in addition, a high concentration of inert ingredients--carbon dioxide, water and nitrogen. Typical composition for low-BTU gas made from coal is as follows:

11% -- Carbon dioxide
12% -- Carbon monoxide
17% -- Hydrogen
2% -- Methane
31% -- Nitrogen
27% -- Water (steam)

The heating value ranges from 120 to 150 BTU per cubic foot. This heating value is only a fraction of pipeline gas. For this reason, it is generally accepted that low-BTU gas cannot economically be shipped long distances. The high concentration of carbon monoxide also makes it unsafe for residential and general use. However, when considered for industrial or power plant use, low-BTU gas could find application if economics and other factors are properly resolved.

Prior to the abundance of oil and gas in the United States, extensive industrial use was made of producer gas from coal. For example, in 1926, 11,000 gas producers existed in the United States, providing about 2 percent of the U.S. annual energy requirements. In 1948, the number of gas producers had decreased to about 2,000. Of this number, 50 percent were used in the steel industry, 25 percent in glass plants and the remainder in lime-calcination, pottery and chemical plants. The total annual energy supplied by gas producers in 1948 was about 1×10^{14} BTU's per year--about 0.3 percent of the U.S. total.

Because oil and gas became available at low cost, gas producers never achieved any prominence in the United States. They suffered from a number of limitations--high hydrogen sulfide emissions, tar and phenol entrainment, water pollution, coal and ash particulate emissions and atmospheric pressure operation. The latter limitation meant that capacity of gasifiers was low, requiring a large number of units for large scale generation of gas.

SUMMARY

Technology for gasification of coal to low-BTU gas is available but is not widely used. As shown in Table 32, fixed-bed gasification to low-BTU gas prior to the combined cycle would

TABLE 32

ESTIMATES ON AVAILABILITY OF COMMERCIAL TECHNOLOGY FOR ENERGY CONVERSION

	Electrical Thermal Efficiency (Percent)	When Available
Combined Cycle* Using Clean Fossil Fuels	40	1972
Fixed-Bed Gasification of Coal to Low-BTU Gas	80-85†	1972
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	28	1972
Fixed-Bed Gasification of Coal and Combined Cycle*	40	1975
Fuel Cells Using Reformed Methane	40-45	1976
Combined Cycle* Using Clean Fossil Fuels	45	1978
Fixed-Bed Gasification of Coal and Combined Cycle*	45	1978
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	34	1978
Fluid-Bed Combustion Coal or Residual Oil—Rankine Cycle	38-41	1980
Fluid-Bed Gasification of Coal to Low-BTU Gas	90-95†	1980
Stand-Alone MHD	20-25	1980
Fluid-Bed Gasification of Coal and Combined Cycle*	40	1982
Combined Cycle* Using Clean Fossil Fuels	48	1985
Gas Turbine-Brayton Cycle (Clean Fossil Fuels)	38	1985
MHD-Topped Power Plant	50-52	1985
Thermionic Topping Fossil-Fuel Power Plants	45	1985
Fluid-Bed Gasification of Coal and Combined Cycle*	45	1988
Fluid-Bed Gasification of Coal and Combined Cycle*	48	1992
MHD-Topped Power Plant	55-60	1995

* Brayton—Rankine.

† Chemical energy efficiency.

result in an overall thermal efficiency of 45 percent by 1978. Capital costs of coal gasification plants will be $75 to $85 per KW using tha available Lurgi technology. Development of fluid-bed processing for coal gasification to low-BTU gas is about 10 years behind the Lurgi fixed-bed technology. If successful, these R&D programs might reduce costs to $60 to $70 per KW for large plants (500 to 1,000 MW range). There is some probability that costs will be higher and may even exceed the costs of the Lurgi process which has some latitude for cost reduction.

Stack gas scrubbing processes have been estimated to add an additional $80 per KW to the cost of conventional steam plants (see page 256, *U.S. Energy Outlook*). Gasification and cleanup costs in the range of $60 to $100 per KW indicate that low-BTU gas from coal will be an attractive alternative for electric utilities. Cleanup costs represent about 25 percent of the total costs. The relatively lower cost for making low-BTU gas is due to the fact that gasification and sulfur removal occur under pressurized conditions. Sulfur removal uses well-known technology for hydrogen sulfide (H_2S) removal under concentrated pressure conditions.

In general, gasification of coal to low-BTU gas for existing boilers and large industrial users of energy is not likely to be economical prior to 1985. Some large power plants which have relatively efficient cycles (8,500 to 9,500 BTU's per KWH) may find that retrofitting of coal gasification is economically feasible after 1985. The economics would vary for each installation depending on load factor, size of plant, availability of land and the local cost of coal. Capital costs to make low-BTU gas from coal for small users of energy will likely be at least $100 per KW. Considering these costs, the use of refined petroleum fuels or even synthetic fuels from coal will tend to be preferred energy forms.

It is likely that coal gasification can be used economically in conjunction with newly constructed combined-cycle plants. Figure 15 provides several power cost curves for combined-cycle plants, given five different assumptions about plant capital costs and operating costs. As with most fossil-fuel plants, it can be seen that power costs are closely related to fuel costs.

Technical Review

A basis for technical and economic comparison is the Lurgi Clean Fuel Gas process which has recently been offered for commercial availability in the United States. The process is patterned after the coal gasification process and combined-cycle power plant which has recently been constructed at the Kellerman power station in Lunen, West Germany. Operating experience with this plant will be observed with great interest over the next few years.

Plans are now fairly well advanced by Commonwealth Edison to build and operate a Lurgi coal gasification unit near Chicago. Planning, engineering, construction and testing of a unit to power a 120-MW steam plant and generator are expected to be completed by the beginning of 1976. This unit will test the adaptability of the Lurgi technology to American coals, and it is expected that this test will be of great importance to the utilities and possibly the large industrial consumers of energy.

The Lurgi gasifier is not adequate for strongly caking Eastern bituminous coals. Also, fine coal cannot be adequately gasified, and a large quantity of tar acids and low-temperature tar is produced in the low temperatures (1000 to 1200°F) which exist at the top of counter-current gasifiers. Recently, the Bureau of Mines has successfully gasified Pittsburgh seam coal in their own modification of the fixed-bed gasifier. This gasifier successfully handled the strongly caking Pittsburgh seam coal, with no apparent difficulties. However, units of a larger size such as would be needed in a large power plant generation of gas have not been adequately tested in the United States.

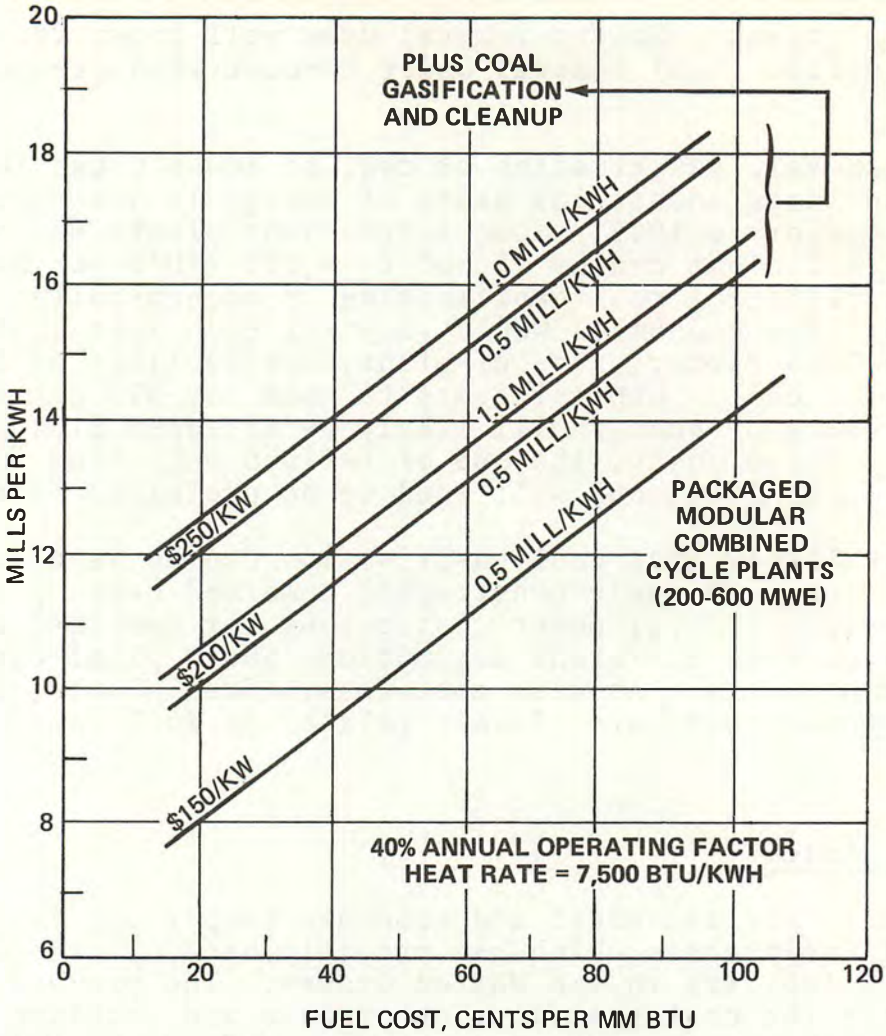

Figure 15. Power Costs of Intermediate-Type Power Plants--1975-1985.

Several versions of fluid-bed and entrained-bed gasifiers have been proposed and tested to various degrees. The Koppers-Totzek Process has been widely used around the world, but this has not been used in an air-blown operation on strongly caking Eastern coals. The use of oxygen rather than air would result in higher heating value gas (300 to 350 BTU's) at a cost not substantially more than low-BTU gas (100 to 150 BTU's) provided by the air-blown process. Since the Koppers-Totzek Process utilizes high temperatures, it has the advantage that no tars and tar acids are made. The atmospheric operation would suggest that gas cleanup will be more expensive than processes which operate at 200 to 500 psi. The BCR (Bituminous Coal Research), Synthane, CSG (Consolidation Synthetic Gas), and Hy-Gas processes have all been proposed for use with air to make a low-BTU gas. It is doubtful that any of these processes could result in a commercial size gasifier much before 1980, however. The economics of these latter processes is very speculative since they use technology that is not yet proven.

The generally conservative electric utility industry will require the demonstration of gasification at the 200 to 500 MW (thermal) level for several years before there is any general trend to gasification of coal.

Economics of Low-BTU Gas Generation

According to Commonwealth Edison, anticipated costs of the Lurgi-type gasifiers for large power plants are expected to be in the range of $85 to $95 per KW (electrical) once operational problems have been worked out. In this analysis, it has been assumed that large installations will have somewhat higher costs of about $144 per KW (electrical) in 1976 to account for normal inflation factors, and also for the fact that the heat rate (BTU coal required per KWH of electric power) will be no lower than about 10,000 for some years to come. This corresponds to a capital requirement on a gas energy output of $600 per million BTU's per day. Capital requirements of small installations are expected to be higher, perhaps of the order $800 per million BTU's per day.

A number of economic parameters are summarized in Table 33. For example, utilities having coal delivery by unit train have lower cost coal than industrial users, and the range of coal costs reflect the importance of delivered coal costs. The thermal efficiency of the current Lurgi technology is taken as 80 percent, and it is anticipated that an improved hot gas cleanup or other heat recovery techniques can achieve an efficiency of 90 percent.

The capital requirements per unit of energy in low-BTU gas in 1976 correspond to the current Lurgi or fixed-bed technology. It is estimated that a 25 percent reduction in capital

TABLE 33

ECONOMIC PARAMETERS

Coal Costs, ¢/MM BTU

30¢, 40¢, 50¢, 60¢

Heat Rate of Electrical Generation

1976–10,000 BTU/KWH
1985– 7,500 BTU/KWH

Thermal Efficiency of Gasification

1976–80 Percent
1985–90 Percent

Capital Requirements, $/KW

1976–large-scale $144, small-scale $192
1985–large-scale $ 81, small-scale $108

Annual Operating Factors

Base load–70 Percent
Intermediate load–40 Percent

Operating Costs

1976–20¢/MM BTU
1985–10¢/MM BTU

Total of Capital Charges

15 Percent–Utility operation
20 Percent–Industrial operation

costs may be possible by a new gasifier and gas cleanup concept. This could be accomplished by a combination of technical developments, all of which are not easily quantified. However, in that gasification, air compression, and sulfur-removal represent the major costs of low-BTU gas manufacture, a cost reduction is possible through an entrained-bed or fluidized-bed gasifier, higher pressure operation, larger diameter gasifiers, etc. The 25 percent potential reduction is regarded as optimistic, however.

The annual operating factors represent ranges for base-load power plants (80 percent) to intermediate-load power plants (40 percent). The 40 percent load factor should also represent the annual industrial situation, wherein the maximum output of energy may typically have to be twice the average requirements. Spare capacity will be needed in the typical application to allow for upsets, downtime for maintenance and the normal fluctuations for energy demand.

Operating costs are estimated to be about \$0.20 per million BTU's in 1976, with a possible decrease to \$0.10 per million BTU's for the improved new technology. The total of annual capital charges of 15 percent and 20 percent represents the typical utility or industrial manufacture of low-BTU gas.

Table 34 summarizes the anticipated cost ranges of low-BTU gas for both utility and large industrial generation of energy. In general, low-BTU gas generation looks quite attractive under utility-type conditions. The cost of low-BTU gas, which is generated under base-load conditions, should be about \$0.50 per million BTU's higher than the cost of the starting coal. These costs can be broken down as 35 percent--capital, 43 percent--energy costs and 22 percent--operational costs. Retrofitting coal gasification to older, low-efficiency steam plants which have poor load factors is not likely to be practical or economical.

On the other hand, the self-generation of low-BTU gas does not appear economical for smaller non-utility industrial users of energy. The non-competitiveness is due to the relatively high capital costs for self-generated energy. The load factor for self-generation of low-BTU gas from coal would probably be no higher than 40 to 50 percent, and low-BTU gas would typically have costs \$1.00 to \$1.30 per million BTU's higher than the delivered coal cost.

Conventional liquid petroleum fuels--synthetic liquids or synthetic pipeline gas--are likely to be considerably lower in cost for many years, and low-BTU gas may not be competitive for industry.

After 1985, generation of low-BTU gas on a large industrial scale is likely to be more attractive near sources of low-cost coal.

TABLE 34

ESTIMATED COSTS FOR LOW BTU GAS FROM COAL

Coal Cost (¢/MM BTU)	Capital Requirements ($/MM BTU/Day)	Annual Load Factor (%)	Capital-Related Costs (¢/MM BTU)	Energy-Related Costs (¢/MM BTU)	Operating Costs (¢/MM BTU)	Total Delivered Cost of Low-BTU Gas (¢/MM BTU)
1976 Technology, Large Utility Operation, 1,000-2,000 MW (th)						
30	600	80	31	38	20	89
40	600	80	31	50	20	101
40	600	40	62	50	20	132
1976 Technology, Small Industrial Operations						
40	800	80	55	50	20	125
40	800	40	110	50	20	180
50	800	80	55	62	20	137
50	800	40	110	62	20	192
1985 Technology, Large Utility Operation						
40	450	80	23	44	10	77
40	450	40	46	44	10	100
50	450	80	23	55	10	88
50	450	40	46	55	10	111
1985 Technology, Small Industrial Operations						
50	600	80	41	55	10	106
50	600	40	82	55	10	147
60	600	80	41	66	10	117
60	600	40	82	66	10	158

Application of Low-BTU Gas and the Combined Cycle

Pressure gasification of coal to make low-BTU gas perfectly complements the requirements of a combined-cycle (gas turbine-steam turbine) power plant discussed in this chapter. Figure 6 (p. 17) illustrates the trends for efficiency of electric power generation from fossil fuels which have been gaining momentum from many sources. This is partly due to the more general recognition of the gas turbine as a reliable device by the power industry. These trends are also due to a growing recognition among the utilities that none of the stack gas processes are capable of removing sulfur oxide at low cost. Scrubbing small volumes of gases of hydrogen sulfide while the gas is under pressure is likely to remain a superior technical and more economical solution to that of scrubbing large volumes of gases of sulfur oxides at atmospheric pressure. In addition, scrubbing or absorption techniques are likely to be superior to electrostatic techniques particularly for the removal of the very small particulate matter. Other advantages for low-BTU gas are that flame temperatures are lower, and extremely low concentration of nitric oxide should be more readily achievable. Finally, the plants are relatively compact and have low cooling water requirements.

The overall efficiency of the fixed-bed coal gasification, when applied to the combined cycle, is about 36 percent in 1972. This is based on the Kellerman plant in Lunen, West Germany. A gas turbine with an inlet temperature of about 820° C (1508°F) is used in this plant. Calculations have shown that if intermediate superheating of steam is used in the steam portion of the cycle, overall efficiency of the plant will be 40 percent (heat rate of 8,500 BTU per KWH). This is an extremely high efficiency which already exceeds that of super-critical high-pressure steam cycles with coal. With such a low heat rate, costs per KW of electrical generation will be reduced.

It should be noted that combined-cycle plants which are offered for sale in this country are not as efficient as combined-cycle units in Europe and Japan. However, the U.S. units use low-cost steam boilers that give a relatively poor use of gas turbine exhaust heat and do not have reheat techniques on the steam turbines.

An overall improvement in efficiency and economics of coal gasification with the combined cycle can be forecast for the future. This is based on a variety of technological events, many of which are already far advanced. Some of the technological trends that will affect this approach to power generation are noted in Table 35.

Using the existing technology as a base case, Table 36 summarizes probable economic and technological limits over the next 15-year period.

In general, improvements in economics and technology can come in a variety of ways. However, the more significant improve-

TABLE 35

TECHNOLOGICAL TRENDS AND LEVELS IN COAL GASIFICATION, AND COMBINED CYCLE POWER GENERATION

Level I—Heat and Energy Recovery

- Improved generation of steam and heat recovery from steam, water and low-BTU gas
- Optimization of air flow in gasification and gas turbine combustion
- Optimization of air and steam flows in gasification and steam cycles

Level II—Gas Turbine Technology

- Larger gas turbines (GT)
- Improved metallurgy and use of ceramics in GT
- Transpiration—cooling in GT
- Design of GT specific for power generation
- New GT cycles
- Higher-pressure staging
- Air-fuel flow management in GT cycles

Level III—Coal Gasification and General

- Larger diameter gasifiers
- Improved gas-scrubbing techniques
- Higher pressure gasifiers
- Fluid-bed gasification
- Hot gas cleanup techniques
- Larger train gas cleanup stages
- Larger gasification plants
- Automation of gasification
- Cryogenic generation
- Larger power plants

TABLE 36

SUMMARY—TECHNOLOGICAL AND ECONOMIC LIMITS TO 1985

Level I—Current Coal Gasification

$600/MM BTU/Day
80 Percent Gasification Efficiency
Heat Rate=10,000 BTU/KWH
$144/KW

Level II—With Heat Recovery Improvements, 1980?

$600/MM BTU/Day
90 Percent Gasification Efficiency
Heat Rate=9,000 BTU/KWH
$130/KW

Level III—With Gas Turbine Improvements, 1982?

$600/MM BTU/Day
90 Percent Gasification Efficiency
Heat Rate=8,000 BTU/KWH
$115/KW

Level IV—With Gasification Improvements, 1985?

$450/MM BTU/Day
90 Percent Gasification Efficiency
Heat Rate=7,500 BTU/KWH
$81/KW

ments are only possible through gas turbine technology and gasifier developments.

In the past two years, there has been a general consensus in many circles that the route to improvement of low-BTU gas generation lies in entrained-beds, fluid-bed gasifiers and techniques to clean gas of sulfur and particulates at high temperatures. However, the high-temperature cleanup represents only one route to improved economics as indicated by Table 35.

Because coal gasification and gas cleanup represent a larger fraction of the capital requirements for low-BTU gas generation than they do for high-BTU synthetic pipeline gas manufacture, theoretically there exists a greater potential for improved technology and economics. A more practical viewpoint might be that coal gasification is quite complex and is therefore likely to remain at about $600 per million BTU's or higher for most coals for the indefinite future. Even with these high gasification costs, the gasification of coal with the combined-cycle represents much promise for the use of coal in power generation.

Chapter Nine

TOTAL ENERGY SYSTEMS

SUMMARY

Total energy systems are defined as prime movers driving electrical generators with heat recovery to meet all energy needs in residential, commercial, institutional and small industrial establishments. Their economic appeal rests on high system fuel efficiency (up to about 75 percent) and low energy costs of selected fuels versus network electricity. Natural gas reciprocating and diesel engines and natural gas turbines are the usual prime movers. The number of total energy installations in the United States enjoyed a rapid growth rate, from near zero in 1960 to several hundred in the late 1960's, promoted chiefly by natural gas utility companies. The growth rate in the late 1970's may be augmented by the ready availability of compact gas turbines, built for use in heavy trucks, in sizes up to about 500 horsepower.

A probable U.S. limit of about 14,000 total energy plants is projected, averaging about 2,000 KW of electrical capacity in place in 1985. The effects would be a reduction of 170 trillion BTU's per year or less in fuel use by electrical utilities, and an increase of 58 trillion BTU's per year or less in use of natural gas and diesel fuel in the residential, commercial, institutional and industrial sectors.

Because of the increasingly less favorable economics expected beyond 1975 for natural gas and the marginal rate of return on investment of many current installations, it is not expected that the proportion of total energy installations to total U.S. building construction will increase after 1975.

DISCUSSION

Although, in principle, fossil-fueled mobile equipment (e.g., automobiles) and many large industrial power stations are total energy systems, neither of these extremes in energy demand are within the scope of this chapter. The total energy systems whose effects on energy resource demand distribution remain to be estimated are those that may supplant network electricity in housing, commercial establishments, institutions and small industrial plants.

A total energy system centers around a prime mover, usually either a diesel or gas engine or a gas turbine. Diesel fuel or natural gas is the usual fuel. The prime mover drives a generator. Engine cooling and/or exhaust heat is reclaimed to provide space heating, usually absorption air conditioning, and if needed, steam. Auxiliary boilers and/or direct firing into the exhaust system often are provided to balance heat loads. Cooling towers or ponds frequently are included. Many variations are possible, including the occasional use of boilers and steam turbines instead of engines.

The advantage of total energy systems is their potential overall thermal efficiency--as high as 75 percent under favorable conditions. It is necessary for high efficiency that system loads be predicted accurately and that thermal loads be relatively large in comparison to electrical loads and vary in proportion to electrical loads. This explains the usual preference for absorption air conditioning. Efficient use of waste heat is the key element. A typical supercharged diesel total energy system may produce 1.25 to 1.75 BTU's of reclaimed heat per BTU converted to electricity; the ratio is above 4:1 for typical gas turbine systems. Reciprocating engines are preferred when heat requirements are comparable in magnitude to electrical requirements and in small systems.

Reliability is another necessity. It is achieved by the choice of durable engines and by the provision in practically all systems of standby capacity and scheduled maintenance. Demand charges usually forbid connection to utility power for backup purposes.

Electrical capacities of total energy plants vary widely, from below 50 kilowatts to above 10 megawatts. The vast majority have been in the range of 150 to 1,500 KW. Most installations have been in office and apartment buildings, hospitals, schools, small factories and commercial complexes such as retail merchandising centers. Because of the small and highly varying loads, and correspondingly high fixed costs and lower efficiency, total energy has made few inroads into private dwellings and small commercial buildings.

Aside from the necessity for properly balanced heat/electrical demands in order to obtain high system efficiency, the economics of total energy are critically dependent upon the competitive costs of network power. The economics of total energy systems is discussed in a later section of this chapter.

At present, limited supplies of natural gas are hindering promotion of gas-fueled total energy. For the future, the cost of new natural gas to large industrial or utility customers is expected to increase to about $0.70 per million BTU's by 1980. The cost to smaller users will be higher. Low-sulfur distillate fuels for diesels or gas turbines already cost more than that. But the 1980 cost of nuclear fuel to utilities is expected to be equivalent to about $0.45 per million BTU's, and that of low-sulfur coal in the West will not be much higher.

Coupled with the limited availability of gas for industrial customers, these fuel economics will severely limit the growth of gas-fueled total energy installations after about 1975. However, in the middle 1970's and beyond, gas turbine engines apparently will be produced in quantity for heavy trucks. They will be designed to use distillate fuels and will be easily adaptable to stationary use. They will be available in sizes up to about 500 horsepower (hp), and at low weight per hp and probably low cost per hp compared to present industrial gas turbines. This development is expected to improve the economics of total energy and may offset the adverse effect of restricted supply of natural gas.

Vigorous promotion of total energy began in the early 1960's with natural gas utilities in the forefront. It was estimated that about 30 total energy plants (as defined above) were in place in the Nation by 1962. This number grew to a few more than 100 by 1965, over 200 by 1966, more than 300 by 1967, and about 500 by 1970. The growth rate, in numbers of plants, was semilogarithmic up to at least 1967 and would have resulted in nearly 2,000 U.S. installations by 1970, 22,000 by 1975 and 300,000 by 1980. A 1967 study for the group to Advance Total Energy showed some 32,000 existing buildings in which total energy could be economically attractive, and expected construction during the 5-year period of 1967 through 1971 of about 40,000 suitable buildings, not including industrial plants.

Predictions made as late as 1969 of the number of total energy installations by 1975 have ranged from 25,000 to 135,000. If the figure of 40,000 suitable non-industrial construction projects in the 1967-1971 period is accepted and if this escalates to 60,000 for the next 5-year period, some 100,000 suitable sites might be available. To this must be added some number of industrial sites, certainly not more than equal. The total number of suitable sites, from the standpoint of design feasibility, probably will not exceed 200,000 by 1975. Considering the usually marginal profitability of the investment, the lower projection of 25,000 total energy installations in 1975 appears to be the maximum number that might reasonably be expected. A continuing installation rate of 2,000 units per year beyond 1975 also appears to be as large as could be hypothesized.

Disregarding industrial installations of larger than 5 MW demand, the average installed electrical demand for total energy systems described in the literature has been about 900 KW. The total installed U.S. total-energy-plant capacity in 1975 (at 1,000 KW per site) would not be expected to exceed 25 million KW. Average electrical power use in total energy systems appears to be about 70 percent of installed demand. Total U.S. on-site power generation by total energy systems would, therefore, not exceed about 1.5×10^{10} KWH per year. This is equivalent to a reduction of about 175×10^{12} BTU's per year in fuel use by utilities, which may be compared to 1975 predictions of about $23{,}000 \times 10^{12}$ BTU's per year total fuel use by electrical utilities. The maximum impact on U.S. electric utility fuel use would be well under 1 percent. However, if historical patterns persist, a disproportionate share of total energy systems will be located in PAD District II (East North Central Census Division).

The effects in residential and commercial usage of fuels would include addition of the fuel needed for electrical power and displacement of some residual oil in this sector by distillate fuels and gas. The latter effect must be discounted substantially because of the shifts of the same kind that will be engendered by sulfur-content restrictions.

Total energy systems may average 70-percent overall efficiency, and produce close to 30-percent electrical output in reciprocating engine systems or about 13 percent in gas turbine systems on the basis of heat input. Recovered-heat/waste-heat ratios, therefore, are as good as in conventional heating systems, and the incremental fuel requirements for total energy installations in incremental fuel requirements for electricity is used at close to 100-percent efficiency. On this basis, incremental gas and distillate requirements for total energy installations in 1975 might be as high as about 50 x 10^{12} BTU's per year. This is to be compared with predicted 1975 residential and commercial usage of about 15,000 x 10^{12} per year. The increase is about 0.3 percent, far smaller than the uncertainty of the forecast.

Additional projections for the maximum growth case are shown in Table 37.

There is evidence that the growth rate of total energy installations since 1966 has been much less than these projections imply. The semilogarithmic growth rate during that time corresponds to a doubling period of about 5 years. It is known that nearly 10 percent of prior installations have been abandoned or connected to network power, primarily because of disappointing economic results.

A more realistic projection of the growth of total energy would assume for the future the same ratio of new installations to building starts as in the 1966-1970 period, inasmuch as engineering experience and accurate economic background are now generally available. It has been predicted that building rates must increase as much as twofold in order to accommodate housing needs, and commercial building can be expected to increase in close proportion. A more probable growth case, based on these considerations, also appears in Table 37.

This case assumes that average annual building starts in the 1971-1985 period will be at twice the average rate for the 1966-1970 period. It assumes, as in the first case, that average installed capacity per unit will increase. (Economics will be most attractive in large apartment or commercial complexes requiring multiple engines of several hundred HP, where the incremental cost of a single standby engine-generator will be least significant.)

The effects of the probable growth case on distribution of energy resources in 1975 are negligible and rise in 1985 to approximately the same level predicted by the maximum growth case for 1975.

TABLE 37

PROJECTED GROWTH AND ENERGY SOURCE EFFECTS OF TOTAL ENERGY PLANTS IN UNITED STATES*

	No. of Units Installed	Avg. Elec. Capacity (KW)	On-Site Power Generated (KWH/Yr.)†	Central Station Fuel Replaced (BTU/Yr.)‡	Incremental On-Site Fuel Used (BTU/Yr.)§
Maximum Growth Case					
1975	25,000	1,000	1.5×10^{10}	175×10^{12}	51×10^{12}
1980	35,000	1,500	3.2×10^{10}	350×10^{12}	110×10^{12}
1985	45,000	2,000	5.5×10^{10}	550×10^{12}	190×10^{12}
Probable Growth Case					
1975	1,500	1,000	9.4×10^{8}	11×10^{12}	3×10^{12}
1980	4,600	1,500	4.3×10^{9}	47×10^{12}	15×10^{12}
1985	14,000	2,000	1.7×10^{10}	170×10^{12}	58×10^{12}

* Not including large industrial installations; i.e., more than about 10 MW.

† At average load of 70 percent of installed generating capacity.

‡ At heat rates of 11,700 BTU/KWH in 1975; 11,000 in 1980; 10,000 in 1985.

§ At 100-percent efficiency for electrical load.

ECONOMICS OF TOTAL ENERGY SYSTEMS

The desirability of total energy systems is very much dependent on the particular needs of the power user involved. Factors such as relative amounts of power and steam required and how these requirements vary with time are important considerations for the individual installation. Thus, an economic analysis of total energy was carried out on a particular, fairly typical, 450-KW natural gas-fueled system operating at a rather optimistic level or 75 percent overall thermal efficiency, and at a more probable level of 55 percent. The electrical power generating efficiency was assumed to be 30 percent.* Figure 16 indicates the effect of fuel cost and waste heat utilization on the cost of power generated by this $100,000 capital cost, 450 KW, gas reciprocating total energy system. This figure would indicate that if all the recoverable waste heat could be utilized (45 percent of input power) at today's gaseous fuel cost of about 40 cents per thousand BTU's purchased power costs would have to be about 13 mills per KWH or higher to result in an economic incentive to install this 450-KW total energy system. This analysis used an annual capital recovery factor of 15 percent. This may be somewhat low for such a relatively small investment, but 15 percent was used for consistency with the other system analyses performed in this study.

The technology necessary for total energy plants using internal combustion engine prime movers is well developed. The growth of total energy will depend primarily upon its economics in essentially its present form. Although some technological improvements are probable, they will only modestly modify the cost of total energy as compared to that of network electricity. The reason is made clear in Table 38 (Chapter 13). The costs of other methods of electrical generation depend heavily on capital investment. Improvements either in their thermal efficiency or in the efficiency or unit cost of their components are reflected directly in their generated power costs. The efficiency of the total energy cycle is not open to significant improvement. In fact, the 75-percent efficiency assumed in Table 38 will only rarely be realized. Component costs will be reduced competitively only by less expensive prime-movers, such as the adaptation to stationary use of mass-produced highway truck turbines, possibly in the late 1970's. This cost reduction will affect total energy power costs only in proportion to their relatively small dependence on capital charges.

A major competitive disadvantage of total energy is its labor-intensive nature. Periodic maintenance and daily operating costs loom much larger in these small generating facilities than in large central stations and are not subject to much reduction,

* The basic information used for the analysis is contained in "Total Energy: A Solution to the Profit Squeeze," *American Gas Association Monthly, No. 52,* pp. 18-19 (May 1970).

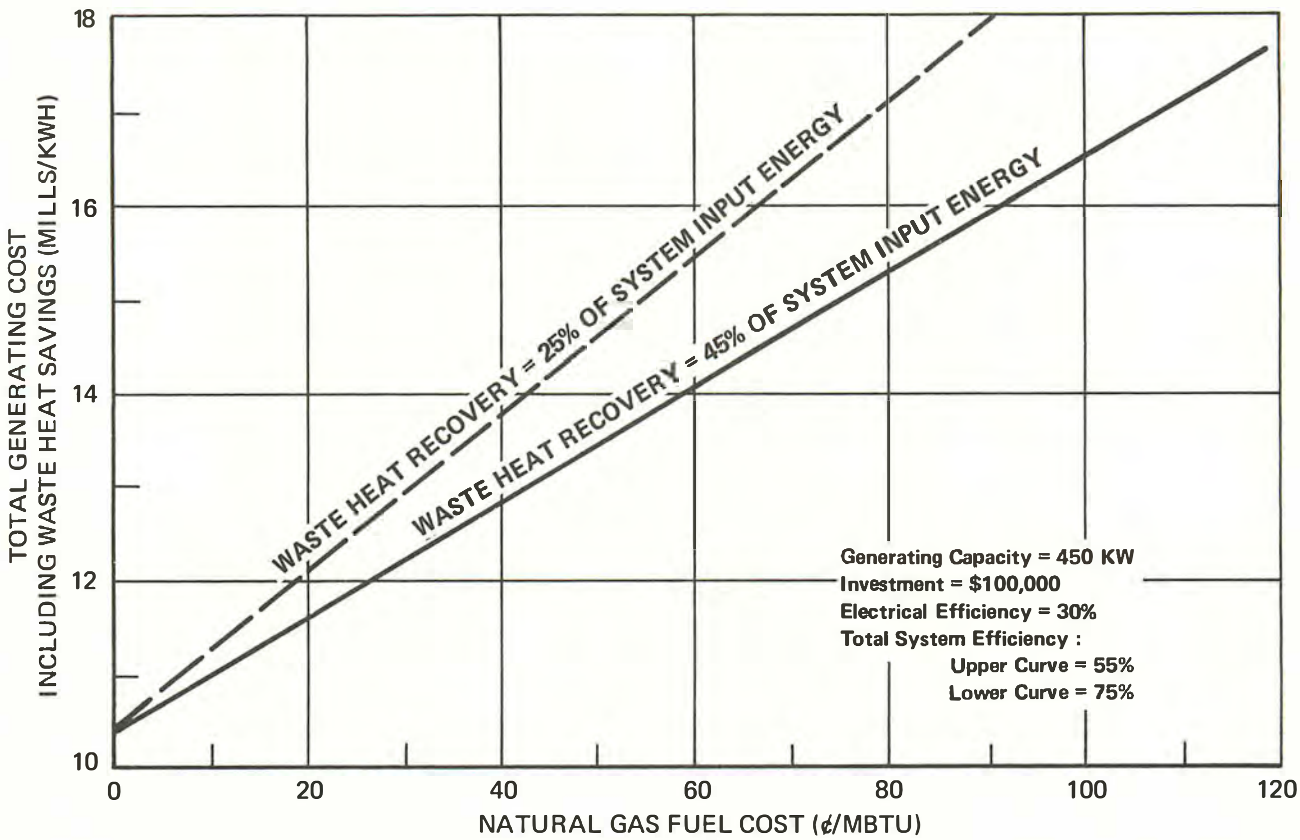

Figure 16. Total Energy-Gas Reciprocating Engine--Effect of Fuel Cost and Waste Heat Utilization.

except as they vary inversely with plant size. The return on investment necessary for privately owned facilities often is relatively high, in comparison to utility-type rates of return. However, this may be offset, in some cases, by the high financial leverage that is customary in large apartment and commercial construction.

An important limitation on growth of total energy may be its dependence on clean (gas or petroleum distillate) fuels. If, in the future, regulations become more stringent regarding discharges of nitrogen oxides from small stationary sources, an additional penalty will be imposed by the cost of its control. Regardless of this, the cost per million BTU's of distillate fuels is already about twice the fuel cost assumed in Table 38, and pipeline gas prices are expected to escalate sharply in the next decade. The average cost of total energy power generation therefore will escalate appreciably more rapidly than that of network power. Even allowing for delivery costs of network power, total energy is now seldom more than marginally profitable. The comparative economics are expected to become increasingly unfavorable to total energy.

At least three paths of development are open for total energy systems. One of these is elimination of mechanical-electrical conversion in favor of fuel cells, thermionics, or other direct conversion devices, still with scavenging of waste heat. Except for the fuel cell route, which is discussed separately hereinafter, the conversion efficiencies of direct conversion devices are too low to admit them to consideration for widespread total energy applications.

A second path of development would adapt engine-powered total energy systems to use lower-quality fuels such as minimally upgraded coal extracts, desulfurized petroleum bottom cuts or synthetic crude oils from tar sand or oil shale. Assuming a price of about $4 per barrel for these fuels, the cost per million BTU's is about double that assumed in Table 38 (Chapter 13), and the R&D investment, therefore, is unattractive unless it can be justified for use in remote locations. The economics of the developed system, in competition with network power, would be worse than those shown in Table 38.

A third developmental path would employ combined cycles, such as thermionic-topped gas turbines or gas turbine-steam turbines, to yield high thermal efficiency without dependency upon relatively high and constant waste heat loads. Although the complexity and maintenance costs of such systems makes them unattractive for common small-scale use, it seems likely that some such systems will be engineered and built for relatively large total energy or on-site electrical power installations.

Given the lower generating cost, and especially the lower maintenance and other labor requirements, of central station power generation versus total energy plants, broad entry of electrical utilities into ownership of total energy plants is not probable. Some utilities have entered into a few such arrangements, apparently under conditions that are not likely to become general.

It appears unlikely that the fuel conservation advantages of total energy systems will outweigh their marginal to negative economics and their proliferation of stationary air pollution sources, in considerations of public policy. This is true particularly because they are incremental users of the scarcest fuels. Therefore, unless as a result of a broader government policy to provide incentives for fuel conservation, no treatment especially favorable to the development of total energy is expected. This would apply both to government encouragement or funding of R&D and to investment incentives.

In summary, total energy plants based on internal-combustion engines are not now usually economically competitive with network electrical power. Trends in fuel supply and cost will make them less competitive in the future. Research and development cannot appreciably improve their economic position. Other energy conversion devices, with the possible exception of fuel cells, cannot economically displace engine generators in total energy plants. Alternative lower-quality fuels are not attractive. No incentive exists for public policy decisions that would encourage or subsidize the proliferation of total energy. Therefore, the growth of total energy installations, as a fraction of United States energy supply and fuel utilization, is not expected to be significant.

Chapter Ten

MAGNETOHYDRODYNAMICS

SUMMARY

The potential impact of magnetohydrodynamics (MHD) on our energy requirements is a function of its promise of achieving higher thermal efficiency, with the result that less primary energy would be required for electric power generation. In addition, the higher electrical conductivity of combustion products from coal has offered the promise of a simple conversion device which is ideal for our most abundant fossil fuel.

Much R&D work on MHD was sponsored by private industry and government in the 1955-1965 period. The work then tapered off after 1965 to the point where only one relatively modest U.S. effort on practical power generation remained in operation in 1971.

Many major technical and engineering problems remain before MHD can emerge as a practical and reliable power device. Major problems include combustion and gasification, the development of high-temperature preheaters, recovery of seed, development of long-life MHD channels and electrodes, corrosion prevention and means to cope with high nitric oxide levels.

Combustion products from fuels such as petroleum distillates and natural gas give low electrical conductivity in MHD ducts. The thermal efficiency of MHD-topped plants with petroleum fuels is significantly lower than with coal or coal-gas as a fuel. While efficiency can be improved by increased temperature and larger magnet size, even greater problems can be created. Improvements in the combined Brayton-Rankine cycle, which are likely to occur before 1985, offer serious competition for MHD. For this reason the electrical equipment, utility and equipment industries today show only limited interest in MHD conversion.

It appears that the MHD concept can first emerge as a peaking or emergency power plant with distillate or residual fuels. With adequate funding, a large prototype peaking plant might be available by 1978.

For MHD to be applicable to base load plants fired by coal, a long-term and costly program extending beyond 1982 seems likely. Even if sufficient funding occurs, some probability exists that engineering problems will not be solved in a way that will be practically or economically acceptable. While competitive and lower capital costs have been projected for MHD-topped steam plants, reliable economics must await the demonstration of MHD on a large-scale for long duration. Base load MHD-topped plants fired by coal are far from successful development. Since peaking plants have only a small effect on our total energy requirements, no significant effect from MHD seems likely before 1985.

Magnetohydrodynamics will have little effect on our total energy requirements in the 1970-1985 period. Furthermore, MHD should not influence the relative mix of our energy for electric power production in this time period. The following are the reasons for these conclusions:

- No recognizable widespread interest in the MHD concept for electric power production exists in the electrical manufacturing industry; the coal, oil or gas industry; the electric utility industry or government.

  Interest is extremely isolated and it is believed that far more support and interest is required to have any chance of a significant thrust forward in the 1970-1985 period.

- From a technical viewpoint the advantages of MHD over existent or prospective power plants when oil or gas is used as a fuel seem quite small. Advantages are peculiar to coal and thus support will continue to be isolated.

- The total national effort on MHD is quite small and the announced and planned duration of the research and development program will extend beyond 1980 and perhaps even 1985.

- Many major technical and engineering problems remain to be solved before MHD can emerge as a reliable device for commercial power production. There is some probability that attainable engineering solutions will not be economically or practically acceptable.

- The evolution of MHD to the point of base-load plants will be time consuming and costly. In order to inspire the confidence for widespread acceptability, long-duration testing with large units and a variety of coals will be required. Reliability of MHD base load would have to approach the reliability standard of other fossil plants and nuclear plants which can evolve in the 1970-1985 period.

- The normal 6- to 7-year delay in construction of electrical power plants would of itself suggest MHD could not have any significant effect in the period before 1985.

A significant and unique problem of MHD is the high nitric oxide level. Although nitric acid plants are being proposed for its disposal, it is believed that this problem will of itself slow the entry of MHD if the power aspects are successfully developed. Nitric acid disposal as fertilizer will be extremely vexing if MHD generation occurs in the populated areas of the eastern United States.

The whole idea of MHD casts electric power generation in a new light. Instead of only electric power production and fuels problems, the operation takes on the aspect of a chemical complex. This is so drastic a change that it is unlikely to occur significantly in any 15-year period.

The MHD concept seems most readily achievable for peaking or emergency plants with relatively clean fuels. The MHD concept does not appear to be adaptable to cycling plants. Since base-load plants are projected furthest into the future, and peaking plants have a small impact on total energy generated, no significant effect seems likely before 1985.

Competitive solutions now exist for coal at a lower efficiency than that promised for MHD. Alternative solutions to the problems of coal combustion with a compromised efficiency of 43 to 45 percent are now being researched. A critical time for MHD and the alternatives would appear to be during the 1978-1980 period. Trends beyond 1985 will depend on the relative success of MHD and the alternatives up to that time.

GENERAL DESCRIPTION OF MAGNETOHYDRODYNAMICS

When any conductor moves through a magnetic field, an electric current is generated. This principle is the same whether the conductor is a solid, liquid or gas. The generation of electric current when the conductor is a liquid or a gas has come to be known as magnetohydrodynamics, or MHD. Conventional generators depend on the high conductivity of copper to produce current at high voltages. So it is that a liquid or gas can be moved in a magnetic field to produce electric power if the conductivity of the fluid is high enough.

A particular class of MHD generator has lately attracted much attention. It uses the combustion gases from fossil fuels in an open cycle. Open cycle is distinctive from a closed cycle in that the fluid is replenished and exhausted in a continuous manner. This report is confined to open-cycle MHD using fossil fuels, since it is commonly agreed that the closed-loop type will be peculiar to high-temperature nuclear reactors using confined helium and is further into the future.

The use of combustion gases to generate electric current directly from fossil fuels is complicated by the fact that the peak temperatures reached in combustion are too low to give high conductivity. The peak temperature when fossil fuels are burned in ambient air ranges from 3,000 to 3,500°F. However, temperatures of 4,300 to 4,700°F, with the gas additionally doped with potassium or cesium ions, are required to give high enough conductivity for MHD.

One approach to high temperatures is to use pure oxygen or air diluted with some oxygen. This effectively reduces the need to heat up nitrogen in air, and higher temperatures can be reached. Another approach is to use the hot exit gas from the MHD generator to preheat incoming air. For example, if air is preheated to about 2,200°F, the peak combustion temperature with air and fuels will be about 4,500°F. Even at this temperature, the conductivity of equilibrium combustion gases is too low. Concentrations of potassium or cesium ions must be in the range of 0.5 to 1.5 percent by weight of the total mass flow. Since air is the major part of the mass flow, seed material represents from 15 to 25 weight percent of the fuel flow, and its recovery and reuse is economically essential.

The often cited advantage of MHD over conventional methods for power production is its simplicity. Electrical power is generated directly without any need to go through any intermediate staging. For example, the common steam-turbine method of electrical generation goes through four stages in the conversion of the chemical energy of the fuel to electrical energy. The MHD approach actually uses three stages, but two stages are conducted almost simultaneously so that only two energy conversions are involved (Figure 17).

The conventional steam boiler-steam turbine method of electrical generation has evolved to the point of having an economical, maximum thermal efficiency of about 41 percent for coal and 37 percent for gas and oil. Steam-turbine-inlet temperatures are limited to about 1,050°F for coal and gas boilers and about 1,000°F for residual oil containing vanadium. The low efficiency of the conventional method is not really related to the number of stages. Rather it is due to the fact that the energy is allowed to degrade or increase in entropy before any attempt at conversion is made.

The diagram shown in Figure 17 suggests that MHD is a relatively simple way to generate electricity. But this simplicity is far from correct in the practical application of MHD.

Conductivities which can be reached with preheated air and seed ions are still quite marginal for MHD alone to generate electricity at high efficiency. The reason for this is that the expansion of the gas in the MHD channel causes it to cool to the point that the conductivity decreases. Power output of the duct decreases with conductivity, and even though the exit gas is still very hot, direct power cannot practically be extracted from the gas. Actual efficiencies of even fairly advanced MHD ducts range from 20 to 30 percent. To obtain high efficiencies of 50 to 60 percent, a combined cycle is typically proposed, the exit gases from MHD being passed through conventional steam plants. The MHD aspect is only used as a topping device, a portion of the electrical output being obtained in a bottoms steam plant.

It is this necessity to add and recover seed, preheat air to high temperatures and to pass potentially damaging seed material through steam plants as well as the possible need to recover sulfuric acid and nitric acid which moves MHD from a relatively simple concept to a complex one.

RESEARCH AND DEVELOPMENT

In the period prior to 1955 practically no interest existed in MHD, as evidenced by the small amount of literature on the subject. Westinghouse studied the MHD concept in the period from

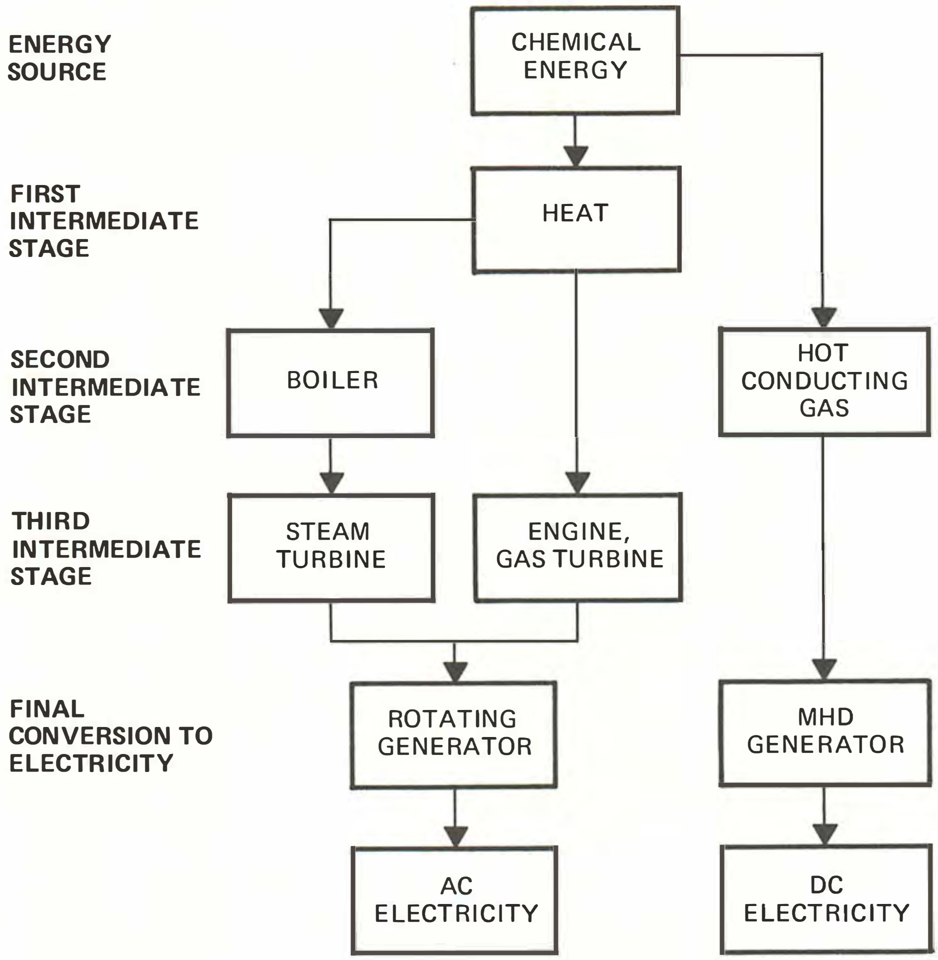

Figure 17. MHD Generation of Electricity

1941 to 1946. Although a fairly sophisticated MHD generator was constructed at this time, no practical amount of usable power seemed possible. Interest in the energetics of plasma from the viewpoint of rocket propulsion provided a better understanding of the electrical properties of hot gases in the period after the war. This basic work seemed to provide an intense practical interest in MHD, as evidenced by a large volume of reported work in the 1959-1966 period. In this period, a number of MHD generators were built which demonstrated the technical feasibility of direct generation of electric power. Although most of the models were small devices, one relatively small duct developed a power of about 30 megawatts. Smaller generators have been operated for several hundred hours duration with no apparent limit on longer duration.

A significant portion of the small-scale work has been confined to the study of plasma properties. Also, liquid oxygen has been widely used instead of air. This option permits the required high temperature without the need for a preheater. For much of the work, relatively clean fuel oils have been used. As noted by the recent Office of Science and Technology (OST) report, the MHD work to date has not adequately faced the problem on the use of coal or coal-derived char as a fuel.[6]

In the period from 1966 to present, only limited development work has been accomplished in the United States. An extensive number of papers have appeared, but these have mostly been confined to reviews of past MHD work and proposals or solutions to some of the problems. Some work has been occurring in Japan, Russia, Poland and East Germany.

The only significant research and development now being conducted with a power generation goal is the effort by Avco Everett Research Laboratory, Inc. in Everett, Massachusetts. One program jointly sponsored by Avco and the electric utilities would have involved about $8 million over a 5-year period from 1970 to 1976.

A national R&D program involving several options has recently been proposed by Avco. The Office of Coal Research is also now studying various plans for an MHD program for coal. One likelihood is that the overall U.S. program will amount to about $4 million per year over the 1971-1975 period. Testing of burners, coal MHD channels, seed recovery equipment and preheaters would make up the first 3-year effort. A small-size unit operating on coal--approximately 2 to 3 MW--would be tested from 1973 to 1976. A large-size unit of about 50 MW would then be designed and operated on coal in the 1976 to 1980 period. The full R&D program through 1980 would cost about $68 million. The successful completion of the planned full-plant program will depend on the success of component research.

Successful development of a prototype MHD plant will depend on the steady evolution of success of the national program. Assuming that such a program culminates in the success of a pilot plant in 1980, it is a reasonable certainty that larger equipment must also be demonstrated. Demonstration of a 300- to 500-MW unit may be necessary for several years. Delays with solutions to engineering problems and the availability of funds will most likely force large-scale MHD beyond 1985. Already there has been a delay of the electric utility program by about 1 year, and the national program may also be delayed about 1 year.

Development of a large-scale MHD unit is proceeding in Russia, and the Japanese are following with a somewhat smaller scale program. The British and French programs on MHD have been discontinued. The British effort had been quite intense but on a somewhat smaller scale than the 1959-1966 U.S. effort. Various reasons have been given for the curtailment of the British and French programs. The British have been said to have made a commitment to nuclear energy. But the comments of at least some of the people connected with the British effort are that the problems are too difficult and would require a long development time.

Any overall viewpoint of the electric utilities toward MHD is difficult to gauge. Some of the MHD development work in the past has been sponsored by the electric utilities. A relatively recent program aimed at a peaking or emergency power plant has been actively sponsored by some of the Eastern utilities and Edison Electric Institute.

Much of the direction and interest for MHD continues to come from the Office of Coal Research. The national program now being studied and considered by the Office of Coal Research has, as a potential goal, MHD base-load plants burning coal or coal products. This interest is related to the greater technical advantages for carbon-rich fuels.

Because MHD has the aspect of being peculiarly most advantageous to coal and since many of the problems appear to be of long-range and basic nature, no widespread interest seems to exist among combustion and electrical equipment manufacturers. It is perhaps for this reason that the recent OST report recommended that federal funding continue to support MHD. Interest seems to be increasing again in MHD, for it appears that it may offer some additional solutions to the environmental problems. The nitric oxide problem of MHD is self-created, however.

No crash R&D program on MHD is therefore likely. Until significant advances are made in the solution to some of the engineering problems, there is little likelihood of any significant financial support by private industry.

STATE OF TECHNOLOGY ON MHD

The following section reviews the state of technology on MHD. Some of the areas which need further development are covered.

Combustion and Gasification

For the MHD concept to be successful, combustion must be extremely intense and under pressure with little or no heat losses by radiation. The pressure is required because the MHD duct operates at 4 to 10 atmospheres, similar to a gas turbine. Combustion pressure would have to be about 5 to 11 atmospheres, which does not appear difficult to achieve. Intense and rapid combustion is also necessary to keep the cost of the combustor nominal.

Considerable research and development on intense combustion has been carried out both in the United States and Europe. In Europe a part of the incentive for pressure combustion has been tied to MHD. In this country there has been a general economic incentive to reduce the overall costs of boilers. Small intense-combustion boilers are already available for naval vessels, but these have maintenance problems.

The temperature of combustion in MHD is considerably higher than in boilers. Peak temperatures may be 4,300 to 4,500°F, in contrast to about 3,000°F for ordinary flame temperatures.

How to design a combustor and keep heat losses down is a very demanding problem. In a conventional boiler, the molten slag particles are purposely allowed to radiate to water-cooled walls, and loss of sensible heat with ash is usually quite low. In some of the MHD proposals, molten slag is withdrawn from a multi-stage combustor before the combustion gases go to the MHD duct. This separates most of the slag (85 to 90 percent) from the more volatile seed. While some type of heat recovery from the slag may be possible, it appears that some new concepts and developments are required. A layer of molten slag along the combustor wall in cyclones could serve as an insulator and prevent heat loss at low temperatures of 3,000°F. However, at MHD temperatures the slag layers will be highly fluid and will not act as a good insulator. The type of combustor would likely be peculiar to a specific coal.

In the British experience with MHD, heat loss in the burners with slag-free fuels was said to be 5 to 7 percent. Presumably, high heat loss was experienced due to hot wall radiation.

Avco has suggested that a heat loss of 2 to 2.5 percent should be achievable. Heat loss must be kept to a minimum so that high temperature and conductivity are possible.

To alleviate some of the problems anticipated with ash in the MHD combustor and duct, gasification of the coal prior to electric generation has been proposed. The manufacture of a producer gas, if it could be done at high thermal efficiency, could alleviate some of the slag problems. Some of the development work on coal gasification which will be proceeding simultaneously in the 1970-1980 period might provide some suggestions. The use of a synthetic pipeline gas for MHD is of course ruled out because the thermal efficiency of this kind of gasification step is no more than 60 to 70 percent.

Air Preheaters

Problems with preheaters are mainly those of lack of suitable materials of construction. High-temperature steels might allow preheaters to be operated to about 1,650°F. Above these temperatures refractories must be used. Magnesite, or other refractory checkerwork, beds of pebbles and heads of molten slag have been proposed and tested to varying degrees. The most promising material is pure magnesite. Avco has shown that refractories such as magnesite can be successfully employed to temperatures of 2,000°F with ash and seed-laden gases and up to 3,000°F if the ash is absent from the gas.

The air preheaters are of the regenerative storage or recuperative type, and additional work is required to evaluate the behavior in long-term running with inorganic salts as found in coal.

If coal is used as a fuel and seeding is with the potassium salt, a 2,000°F preheat temperature could allow efficiencies of 50 percent for the combined cycle. The use of char and cesium seed would allow a maximum efficiency of about 52 percent at the same preheat temperature. Any increase in preheat temperature would allow an even higher thermal efficiency. Each 200°F increase in preheat temperature would add about 1.5 percent increment to efficiency. At a 3,000°F preheat temperature, overall efficiencies could approach 60 percent.

The key to the success of the promised high efficiencies in MHD lies in the direction of improvement in preheating technique. Obviously much work remains to be done before it can be shown that preheating can be made to work for long periods of time with a variety of fuels.

There is no need to have a preheater if pure liquid oxygen is used. This option attains the required high temperatures without the need for preheating. It seems to be a widely held view, however, that pure oxygen cannot economically be used. This can be seen when it is realized that the energy required to separate oxygen from air is about 326 KWH per ton. This is about 9 percent of the heat generated when fuels are burned in oxygen. This value must be subtracted from the output of the generator. For example, if the heat of combustion of a fuel is Q, the efficiency of an advanced-model MHD duct is about 30 percent with an output of .30Q. The subtraction of the energy required to manufacture pure oxygen would place the efficiency of the MHD duct at 21 percent.

There may be some conditions under which air with some oxygen could be used to compromise the required high temperature in the preheater. The use of chemical regeneration has also been proposed to bypass the need for a preheater section. This latter technique has not been explored, however.

Seed Recovery

To achieve high electrical conductivity of 4 to 6 mho* per meter in the 4,000 to 4,600°F range, it is necessary to add 0.5 to 1.5 percent by weight of the total gas as either a potassium or cesium salt. the chloride salts cannot be used because they have a detrimental effect on conductivity of the plasma. Salts such as potassium sulfate (K_2SO_4) or carbonate are usually considered for seed. Cesium salts are higher in cost but give approximately a twofold increase in conductivity at comparable concentrations. Pollucite ore containing about 28-percent cesium has been suggested. The cost of the ore is estimated to be about $0.60 per pound of contained cesium. Accordingly, recovery of cesium must be about 99.8 percent while a recovery of potassium of about 98.5 percent would be required. A large deposit of pollucite ore exists in Manitoba and this may have some logistic advantage for application to tar sands or Western coals.

* Mho is the practical unit of conductance equal to the reciprocal of the ohm.

Recovery of seed by electrostatic precipitation at high efficiency seems readily possible. This has been demonstrated in a limited amount of work. The high electrical conductivity of gas laden with seed should be an advantage in electrostatic removal.

The successful work on electrostatic precipitation has been conducted at low temperature. The assumption has been made that the seed and ash will be allowable through the complete bottoming steam plant and would be separated at conventional stack temperatures of 500 to 800°F. It is difficult to believe that ash and potassium salts could be transported from the exit of the MHD duct and through a steam-bottoms plant without causing some sticking, corrosion or deposit problems. To be able to use the heat in the exit gas more effectively, seed separation should occur at 1,600 to 2,000°F. Considerable development work is necessary to assure that this could be done economically without corrosion. The alternative, of course, is that a development program on boilers and superheater arrays be carried out.

Ash slag points for coals can vary from 2,000 to 3,000°F. Highly viscous liquids and sticky solids exist for K_2SO_4 and vanadium sulfate (V_2SO_4) to very low temperatures. Despite the fact that residual oils have a low ash content, the phase and corrosion problems call for additional development work.

Problems on Steam-Bottoms Plant

How simple the solutions will be for the bottom part of the combined MHD cycle will depend on the type of ash in the fuel burned and the effectiveness of the ash and seed separation. It has been commonly proposed to separate the ash from the seed material at about 3,400°F. At this temperature the seed will be a gas, and solid ash should be separable by a hot cyclone. Some problems are anticipated because it is not expected that complete separation will occur. Deposition of some slag and seed might then occur on some of the heat-transfer surfaces.

The presence of such a high concentration of alkali sulfate salts poses a completely new problem for the bottoms-plant boiler. When one considers the development which has gone into specific kinds of boilers for various kinds of coals, it is clear that some development must be accomplished for MHD downstream equipment. Vanadium and potassium sulfates continue to remain in a liquid form as low as 600°F. The ability to cope with these problems requires extensive additional work.

Some writers have suggested that the only new piece of required equipment in the MHD cycle is the generator duct. This does not appear to be correct. Many development problems are yet to be solved on the bottoms plant. If electrostatic seed separation can occur at 1,600 to 2,000°F, fewer problems might be involved with downstream heat-transfer surfaces. However, this also will require a development program.

MHD Ducts and Electrodes

Considerable progress has been made in the development of the MHD duct and electrodes. Indeed, it is probably true that this aspect of the technology is furthest along. Long duration of duct configurations is necessary for ash-containing fuels. The duct walls, electrodes and insulating materials will be subjected to 4,300 to 4,700°F temperatures. Structural changes due to chemical attack and attrition by the corrosive gases and molten slag are possible in long-term running. In addition to this, electrical integrity of both insulators and electrodes must be maintained. The most promising materials for electrodes are zirconia, silicon carbide and rare earth borides. In some testing, vaporization of zirconia has occurred, and it has been necessary to add zirconia in the gas to replace that which is lost. This appears to be a solution but more work must be done before the economics of this can be proved. The addition of zirconia or alumina to the gas stream may complicate the phase behavior of the seed and ash. This would have to be checked by testing.

In some cases, retention of duct and electrode integrity has been achieved by ingenious cooling with water. It has been pointed out by other workers that such cooling will lower the overall efficiency of the MHD portion of the plant. The maintenance of hot walls is preferred. This could be done by cooling with superheated steam, but the testing of this option has yet to be done. Hotter walls will pose more of a problem with electrical integrity in long-term running.

The development of an MHD generator will certainly be easier for clean fuels than for coal. It is for this reason that the emergency or peaking plant based on fuel oil is the most likely prospect for the 1980-1985 period.

Recovery of Sulfur from Seed

If a sulfur-free fuel is used, the carbonate salt is formed; if the fuel contains sulfur, the sulfate salt is formed. If potassium is used as the seed material, the stable salt would be K_2SO_4 with sulfur-containing fuels.

If sulfur is to be recovered as in the Claus process, then the sulfate salt must be reduced with carbon monoxide (CO) or hydrogen (H_2) to form carbonyl sulfide (COS) or hydrogen sulfide (H_2S). The presence of some ash is likely to complicate this reduction. No work has been done on this reduction problem, but the simultaneous recovery of nitric acid and sulfuric acid is an alternate solution which may be preferable.

Nitric Oxide Problems

MHD ducts operate at very high temperature, and nitric oxide (NO) is produced in high concentration. Nitric oxide concentrations from MHD generators have agreed with equilibrium concentrations which would be predicted by thermodynamics. Values ranging from 10,000 to 15,000 parts per million (ppm) have been measured. Several suggestions have been made to cope with this problem. One proposal is to recover nitric acid for fertilizer production. A 1,000-megawatt MHD combined-cycle plant would produce 1,500 tons of nitric acid per day. The high concentration of NO in the stack might allow the simultaneous recovery of nitric and sulfuric acid. Such a process is now being developed and is based on the old Lead Chamber acid process. At this point, this process has not been adequately studied at stack gas concentrations. The necessity for converting MHD plants into nitric acid plants as well as sulfuric acid plants will be a disadvantage for the acceptance of MHD. In the longer term, nitric acid recovery could have some definite advantage.

It should be pointed out, however, that nitric oxide problems are not now unique to MHD. Because NO formation is favored by high temperature and excess oxygen, intense combustion which is necessary to burn coal completely and rapidly in conventional boilers is also likely to form high nitric oxide. In contrast, relatively high flexibility exists for controlling the nitric oxide concentration from oil and gas firing in conventional boilers. Nitric oxide reductions of from 70 to 90 percent are achievable through modifications in burning through staging, etc. This is not so easy with coal, however, for constraints of deposits and corrosion on tubes, and requirements to obtain complete combustion, are not so compatible with nitric oxide reduction. Two-stage combustion with liquid and gaseous fuels can reduce nitric oxide as much as 90 percent. Liquid coal fractions should also allow the flexibility for NO control through burner variations.

While the formation of nitric oxide is not now unique to MHD, advances in burner technology and coal conversion are likely to make MHD, with its high NO evolution, a unique problem in the future.

Two-stage combustion has been proposed for MHD operation to reduce nitric oxide. Levels of 1,000 to 2,000 ppm of nitric oxide are obtained which may be too high for atmospheric discharge but too low for economic recovery. The speed of MHD development then must depend on methods to solve the nitric acid recovery problems.

Conductivity and Magnetic Field

The most important aspect of the combustion gases in an MHD duct is the effective electrical conductivity. Because hydroxl ions from the combustion of hydrogen react with seed ions and also with electrons, the electrical conductivity of fuels rich in hydrogen is quite low. Natural gas combustion products have a conductivity about 50 percent that of coal products in the 4,100 to 4,500 °F range. Air for natural gas must be heated about 600°F higher in temperature than air for coal to get comparable conductivity. To reach an electrical conductivity of 6 mho/meter, air preheat temperature for natural gas would have to be about 2,600°F. In contrast, air for coal combustion would be heated to about 2,000°F. Thus, the thermal efficiency to be expected with natural gas is very much lower (see Figure 18). In theory, higher magnetic fields and high preheat temperatures could be used with hydrogen-rich fuels. However, the economics and practicability will have to be extensively studied as to what specific magnet size, pressure drop across the duct and preheat temperature should be used for each fuel. Efficiency will decrease as the magnet size and the pressure increases, since parasitic losses of power for the magnet and blower must be subtracted.

The effective conductivity is not independent of magnetic field. Some unpredictable conductivity/magnetic field factors may well occur as size of MHD is scaled up. Unfortunately, the precise electrical behavior of an MHD generator is not observable until it is built. The electrical conductivity measured on small-scale equipment has agreed fairly well with that predicted by theory. However, some anomalies should be expected as one goes to larger size ducts with a variety of fuels. While wall effects are minimized by going to large-scale equipment, any requirements for field uniformity at a given cross section may not be so easily achieved. These factors suggest that MHD generation would have to evolve steadily through various developmental sizes. All of this would make the development more costly and postpone large-scale versions of MHD.

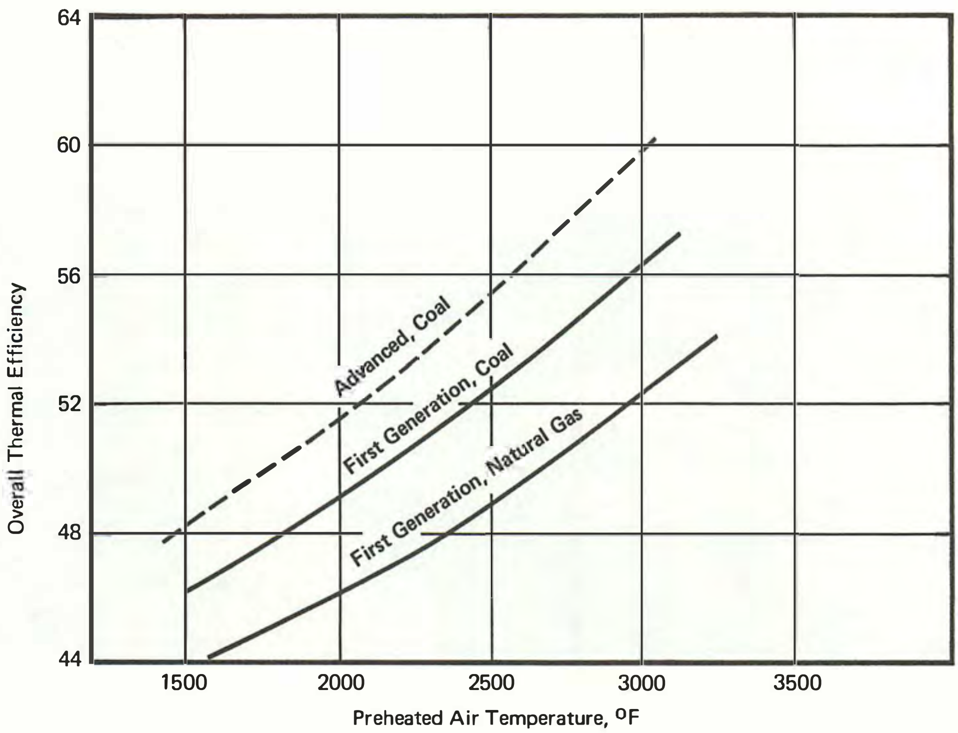

Figure 18. Predicted Efficiencies with Combined-Cycle MHD.

ROLE OF MHD IN ELECTRIC POWER GENERATION IN THE 1970-1985 PERIOD

General Makeup of Power Generation

It is the general nature of electrical generation that plants can be divided into three categories; base load, intermediate load and peaking load (Figure 19). Base-load plants are operated nearly full-time throughout the year. In actual practice the operating factor may range from 60 to 95 percent. Although base-load plants might only account for 45 to 50 percent of the total capacity for a typical utility, they usually account for 70 percent or more of the output of KWH. Accordingly, incremental changes in base-load generation plants can have a greater impact on fuel mix.

Intermediate-load plants do not operate full-time and have been referred to as "daylight plants" or "five day plants." Peaking plants may operate less than 15 percent of the time or even as low as a few percent if they are a part of spinning reserve or standby reserve.

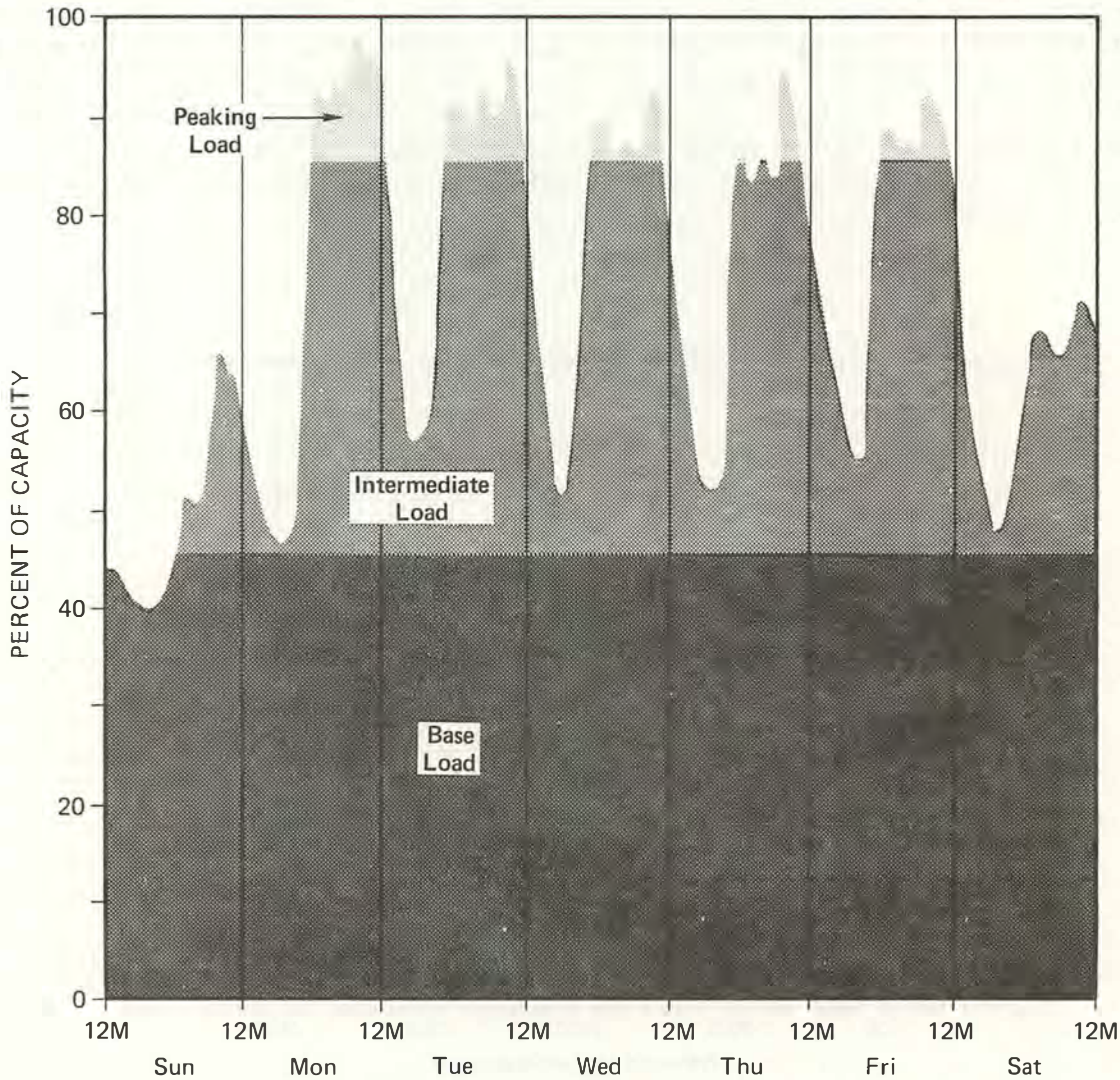

Figure 19. Typical Sendout Pattern of Electric Utilities.

It is unrealistic to believe that any change in this generation pattern will occur in the 1970-1985 period. This pattern is fundamentally related to daily and weekly cyclic behavior of people, commmerce and industry as well as the weather.

In recent years, it has worked out that the newest and most expensive plants, as they came on line, were relegated to the role of base-load plants, displacing older plants from that role. It makes economic sense to run the most efficient equipment around the clock if at all possible. The advent of any new base-load plant would allow electric utilities to place older plants in the intermediate-load category. Usually, these older plants would have been less efficient, and a savings in fuel costs would also have been effected by such a displacement.

A change in this pattern has been occurring in recent years. First of all, new fossil-fuel plants which would be added for base load have approached an efficiency barrier of 39 to 41 percent for coal and 34 to 37 percent for natural gas and fuel oil. Very slight improvement in thermal efficiency for conventional fossil plants seems possible in the 1970-1985 period. There is some indication that the efficiency will drop 1 to 2 percent as it is necessary to add wet or dry cooling towers and to reheat stack gas to give it loft after stack gas treatment processes.

Nuclear plants must automatically be placed in the base-load category. This is because their capital cost is high and for technical reasons cannot or should not be operated in a cyclic manner. The advent of mine-mouth coal-fired plants with high investment in transmission lines demands that this kind of coal plant also be in the base-load category. As water cooling towers, fly-ash removal equipment and stack gas sulfur removal are added to coal plants, the amount of capital invested becomes even higher, thus more quickly evolving coal to a base-load concept. Similar arguments should be true for plants using high-sulfur fuel oil if environmental control devices are added.

MHD as Base-Load Plants

By definition, base-load plants operate from 60 to 100 percent of the time. The general thrust of the national effort on MHD has been in the direction of large base-load plants wherein the MHD generator is a topping device.

While the current concept on MHD is that the capital investment per kilowatt should be low, the economics that have been presented appear too optimistic. Costs of $70 to $120 per KW have been projected by various groups. The addition of sulfur recovery and nitric acid recovery will almost certainly place MHD plants in the area of high capital cost items.

The concept of seed storage, seed recovery, sulfur recovery and seed regeneration and nitric acid recovery make it unlikely that MHD plants can operate satisfactorily in a cyclic manner. It is for these reasons that it is believed that MHD would fit best in the base-load category.

Because of the variable nature of ash in coals, base-load operation for a diversity of coal fuels will be the status most difficult to achieve. For this reason it is believed there will be no attainment of base-load plants before 1985. Long-term duration operation (1 to 2 years) of sizes in the 300 to 500-MW range must be achieved before there can be any trend to this kind of power generation.

Some of the unique properties of MHD suggest that its future potential role could be in large-scale mine-mouth coal plants. Since the electrical output from MHD is proportional to volume of the channel, costs per kilowatt should decrease very rapidly as units are scaled up to 2,000 to 5,000 MW. Also, the prospective problems of disposal of nitric acid would be less serious than with small widely scattered plants east of the Mississippi. Sulfuric acid and nitric acid recovery should make more economic sense closer to agricultural markets in the Midwest and Far West. It should be noted that MHD could also have some future role for the Canadian or U.S. tar sands. For example, a large-scale coking operation with the coke used as a fuel for MHD is a possibility. Such a scheme might allow a coker distillate to be made which could be shipped by pipeline with minimum upgrading. The prospect of vanadium-sulfur-potassium phase and corrosion problems could be difficult to cope with in heat-transfer equipment downstream from the MHD duct. However, the prospect of a large reserve of fuel with uniform properties could justify the effort to solve this problem.

Various proposals have been made for the use of oxygen plants in combination with coal gasification plants. The use of oxygen for gas manufacture and also for adding high heat to MHD may be more economically accomplished on a very large scale. The generation of large blocks of DC current and its transmission by DC line also have some possibilities.

The achievement of such scale is staggering in its complexity. The serious consideration of such possibilities must await the development of MHD. There may not be economical or practical solutions to base-load MHD. However, its emergence in a base-load role would certainly be beyond 1985.

MHD as Intermediate-Load Cycling Plants

Characteristics of intermediate-load plants are listed which might be examined to see how MHD fits into the picture:

- Low capital cost
- Flexibility to change load quickly

- Flexibility for daily start-up

- Intermediate size--200 to 600 MW.

While MHD seems to offer the concept of simplicity, low capital cost and flexibility, it does not appear that the overall concept will fit well into the cycling picture. The necessity for adding and recovering seed and the recovery of sulfuric and nitric acid do not seem compatible with the cycling concept.

Up to the present, requirements of steam boilers specifically designed for cyclic service have generally precluded the use of pressures above 2,000 psig (pounds per square inch gauge) and temperatures above 950°F. Some attempt at an increase in pressure to 3,000 psig and temperature to 1,050°F is probably likely in the 1970-1985 period since fuel costs will probably increase.

A number of new concepts in boilers are emerging that make them capable of many start-ups and able to follow load changes rapidly. Gas-fired and oil-fired boilers should continue to be preferred for cyclic operation, although cycling boilers are available that do a good job with powdered coal.

The combined cycle (Brayton-Rankine) using a gas turbine as a topping device and a boiler and steam turbine is now emerging as a low-cost intermediate plant. While gas turbines are now limited to gas and distillate fuels free of vanadium and sodium, various combinations of boilers, steam turbines and gas turbines offer very low incremental power in the range of $40 to $100 per kilowatt. It should be noted that sodium removal from residual fuels supplemented by additives to counter the role of vanadium has promise in the combined cycle. Combined-cycle plants with coal or residual oil-fired bottoms plant and with gas turbines as topping plants will offer extremely high efficiencies with relatively low requirements for cooling water.

On the other hand, an MHD cycling plant would have an extremely limited flexibility for fuels. Output would be highly variable with the type of fuel. The chemical plant aspects of MHD also make it unsuitable to the cycling-plant concept. For these reasons, it is concluded that MHD could not become a serious competitor in the intermediate-load cycling plant in the 1970-1985 period even if the development problems are solved.

MHD as Peaking, Emergency and Standby Power Plants

In the last two years, some attention has been given to the concept of MHD as a peaking power plant. The program at Avco sponsored by several utilities had the development of a high performance emergency-peaking power plant as a primary goal. A secondary objective was to advance the state of MHD toward pollution-free base-load plants. The planned size of this plant is 50 MW. The peaking plant would employ liquid oxygen and fuel oil distillate in the first phase and would switch to partial oxygen enrichment and residual fuel in the advanced phase. The second phase would have been preceded by preheater development that could allow the use of less oxygen. There is now some indication that this peaking program will be merged with the overall national R&D program on MHD.

A number of reports have shown that the concept of fuel oil/ liquid oxygen MHD could be competitive with some of the other peaking devices such as gas turbines and pumped storage hydroelectric. For example, a 225-MW MHD peaking plant was shown to be cheaper than a gas turbine for operations less than 100 hours per year. This operation would represent only about a 1-percent annual capacity factor and would therefore be a highly specialized use. A recent article which polled electric utilities has reported that economical time usage for gas turbines is in the range of 500 to 1,200 hours per year. Thus, it does not appear that early versions of MHD peaking devices could compete with gas turbines.

Some of the reasons which electric utilities have given for the use of gas turbines in peaking are the following in order of importance:

(1) Quick starting ability

(2) Low capital costs

(3) Siting flexibility

(4) Operation and cost savings

(5) Immediate availability.

MHD devices have the ability to start quickly and reach full power within 5 seconds. Gas turbines will come to full power in 2 minutes. It is difficult to judge whether the additional speed of start-up for MHD would have any economic advantage.

The low estimated capital costs for MHD peaking units of $35 per KW for the 200-MW size and $21 per KW for the 2,000-MW size cannot be easily validated. It should be noted that this includes $15 per KW for inversion, so the total capital outlay for the rest of the MHD facility only ranges from $5 to $20 per KW. Costs have been extrapolated from relatively small-scale laboratory size and will require verification. The operation and maintenance costs for an MHD unit using liquid oxygen would be 24 mills per KWH just for the oxygen.

An important advantage of MHD is that it could be used with residual oils containing vanadium. The more widely used and most efficient gas turbines are restricted to fuels such as natural gas and distillates.

The overall economic advantage of MHD originates from the low projected capital costs. The necessity to store liquid oxygen, seed solution and the liquid solution recovered by scrubbing adds complexity to the original simple concept of the MHD generator.

It does appear most likely that MHD can first emerge on a commercial scale as a 100- to 300-MW peaking device. Because the technical problems are not especially serious, this concept may emerge as early as 1977-1978. Such peaking plants would face serious competition from gas turbines and pumped storage hydroelectric. Also standard peaking devices, such as rapid response boilers fired by gas and oil, plus spinning reserve from intermediate plants or even spinning reserve from nuclear plants, should furnish serious competition to the advent of MHD in the peaking role. Even if 10 or 12 such emergency plants totaling 2,000 MW are in service by 1982, the amount of electric power generated would be very low. Such peaking plants would have thermal efficiencies in the 15- to 20-percent range, but they should not measurably increase our requirements for fuels.

THE COMPETITION FOR MHD

Significant and dramatic improvements have occurred in gas turbines in the last 10 years. While historically the gas turbines has been thought to be a delicate piece of equipment, improvements in design and accumulated operating time in the field have brought it to the point of high reliability and acceptability. Many gas and oil transmission companies have switched completely from reciprocating engines to gas turbines in the last 10 years. While the reliability and cost have been improving, the thermal efficiency has also been steadily increasing. One of the principal drawbacks of the gas turbine had been its low thermal efficiency. A significant increase in the firing temperature has occurred in the last several years. While 1,400 to 1,500°F had been the approximate limit for firing temperature, acceptable range on some industrial turbines is now 1,850 to 2,000°F.

The use of a combined gas turbine (Brayton cycle) and steam turbine (Rankine cycle) was once impractical because exhaust steam from turbines had too low an energy to economically generate steam in a Rankine cycle. Gas turbines now operating in the 2,000°F range provide a convenient way to compress and preheat gas and at the same time extract some electric energy from the shaft. Combined-cycle gas turbine/steam turbine plants are now available from at least three manufacturers. The heat rate of these combined-cycle plants is in the range of 9,000 to 9,200 BTU's per KWH. This thermal efficiency exceeds what is now regarded to be an economic limit for super-critical gas-fired boiler-turbines (9,400-9,500 BTU's per KWH).

An important drawback of the gas turbine is that high firing temperatures are not possible with some ash constituents. Particularly devastating are volatile salts such as NaCl, vanadium and sulfur in combination, because these chemically attack materials of construction. Any kind of sticky ash can clog the blades and critical passages, and any solid abrasive particulates will seriously erode the turbine parts. It is believed that the probability of developing turbine blades having a simultaneous tolerance for high temperatures and molten and corrosive ash components is quite low. However, it is believed that the combined-cycle concept, when applied to fuels free of sodium chloride (NaCl), vanadium and other ash constituents, can evolve to the efficiencies listed in the following paragraph (illustrated on Figure 20).

It should be noted that there are several solutions to high-temperature tolerance in gas turbines. These include (1) materials of construction, (2) blade and vane fabrication, (3) cooling and (4) flow management. Intense competition exists in gas turbine development in the United States and Europe.

Thermal Efficiency	Gas Turbine Firing Temperature	When Available
38-40%	1,800-2,000°F	1969-1970
42%	2,000-2,100°F	1975
45%	2,200-2,300°F	1978-1980
48%	2,500°F	1985
54%	3,000°F	?

Much work is carried along by the commercial and military programs for jet engines.

If ash constituents are low in concentration, as in vanadium-containing oils, there is always the possibility that additives can be put in the fuel to change the character of the ash or to neutralize their chemical attack. These possibilities exist for coal liquids and gases from coal combustion, as well as residual oil.

Extensive research on gas turbines fired by coal combustion products appears to have demonstrated that the gas-turbine concept is inapplicable even when fired at low temperature (1,200 -1,400°F). When the variety of ash and volatile corrosive agents in coal-combustion products is considered, it seems highly unlikely that high efficiencies can be achieved through the Brayton cycle. Some possible trends in thermal efficiencies in the United States are shown in Figure 21.

If coal gasification and gas cleanup can precede the Brayton cycle, high efficiencies are then also possible with coal-combustion products. Much research and development has been accomplished on coal gasification, and a number of programs are in progress for the 1970-1980 period. It seems possible that this work will provide some answers to this problem. High thermal efficiency approaching that of a conventional boiler is required in any gasification scheme. Also, the gasification process should not add significantly to the overall cost of power generation. the combination may be a difficult goal to achieve, but can be a possibility.

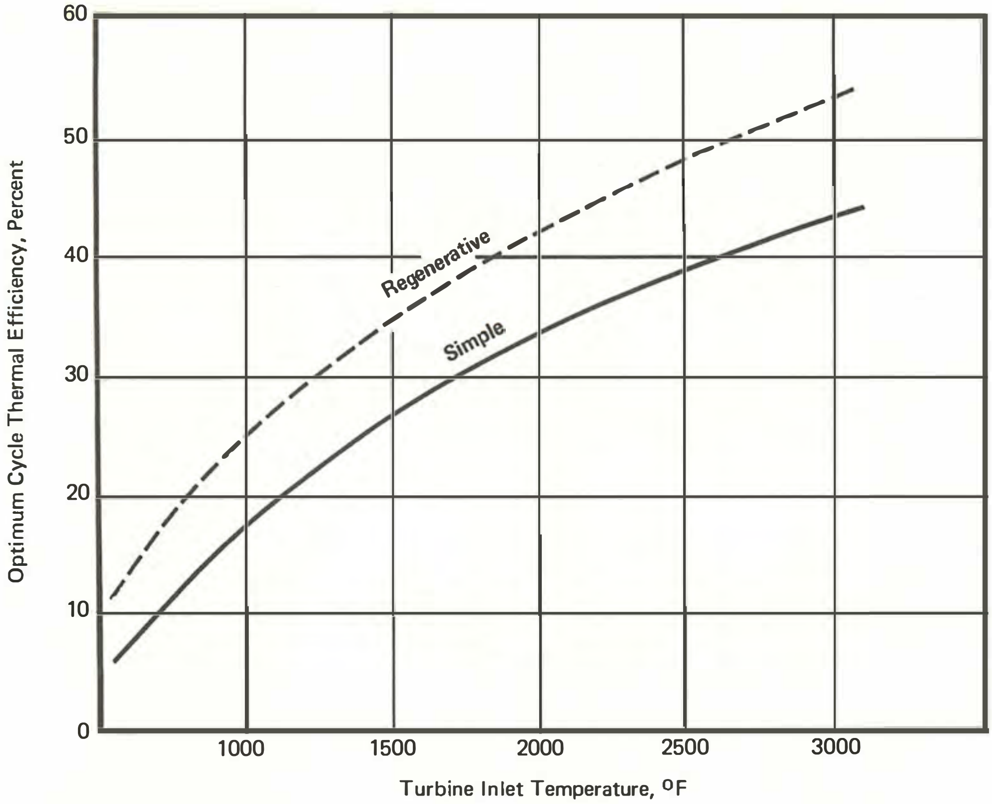

Figure 20. Efficiency of Simple and Regenerative Brayton Cycles Increases with Inlet Temperature.

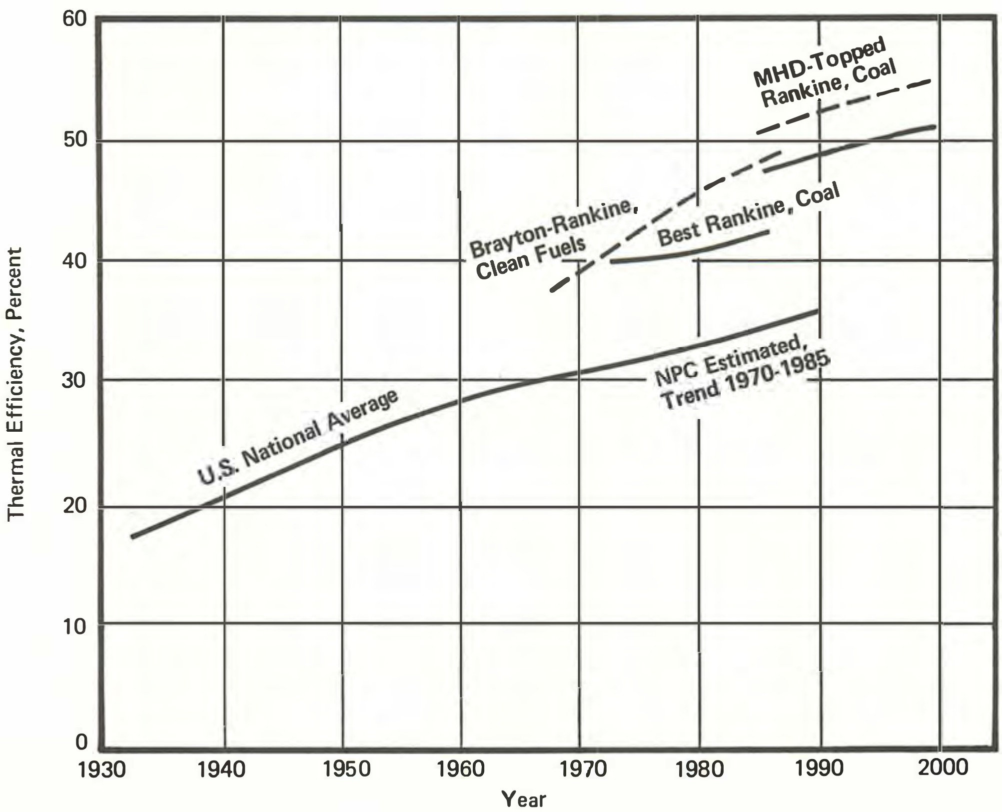

Figure 21. Some Possible Trends in Thermal Efficiency in the United States.

Fluidized combustion under pressure is also being researched with coal and residual oil. Low-temperature combustion gases have a more reasonable chance of being kept free of volatile chloride salts and vanadium compounds. The use of lime in the bed can also capture sulfur oxides. Low-temperature combustion is said to evolve less abrasive ash material than from high-temperature combustion. Low-temperature combustion also avoids the problem of nitric oxide.

Many of the sulfur oxide stack gas processes are now being studied on a large scale. The emergence of some of these processes which are reasonably reliable and acceptable should begin to occur about 1975. These developments could provide some retardation of MHD because sulfur recovery would not then be a peculiar advantage for MHD.

The manufacture of clean sulfur-free liquids from coal is also a possible competitor. It may prove better for the electric industry to place the burden of obtaining clean liquids and gases on the fuels side of the ledger. Methods exist for minimizing nitric oxides in burning. Sulfur-free fuels eliminate the need for sulfur-recovery equipment and the problems of sulfur disposal.

Finally, if clean fuels are available, topping techniques such as thermionics may be more readily possible. The probability seems higher that suitable materials could evolve that are not required to be simultaneously tolerant to high temperature and corrosive chemicals.

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Chapter Eleven

FUEL CELLS

SUMMARY

A fuel cell is an energy conversion device which can convert chemical energy *directly* into electrical energy. It is essentially a special kind of battery. The major distinguishing feature between fuel cells and conventional batteries is how the energy is stored and the reaction products are rejected. In a fuel cell, the chemical energy is stored outside the cell, and longer lifetimes are possible with the external fuel supplies. In a fuel cell, the reaction products--carbon dioxide and water--are typically rejected from the cell. In chemical batteries the reaction products are stored in the cell.

The efficiency of energy conversion in a fuel cell is not constrained by the thermodynamic limitations of engines which operate on pressure-volume-temperature cycles (i.e., combustion engines). Theoretically, higher efficiencies are thus possible.

Much government and private funding supported fuel cell R&D from the middle 1950's through the middle 1960's. Then both government and private interest waned rapidly in the late 1960's, owing to persistent technical problems. Only one fuel cell operating on a practical commercial fuel has yet advanced beyond the laboratory state. Low-temperature cells using noble metal catalysts and pure hydrogen and oxygen fuels were developed, however, and produced for space use.

CURRENT STATUS

Since the middle 1950's hundreds of U.S. and foreign companies have conducted research and development on fuel cells. Much of the work in the United States was done with government funding. Successful fuel cells for aerospace (Gemini and Apollo) were developed, but commercial applications have failed to appear. The major commercial applications sought, which would have represented the largest potential fuel markets, were vehicle power, central power and residential gas total energy. Interest in further R&D began to fade in the mid-1960's, and at present only two major development programs remain.

Intermediate-temperature molten salt electrolyte cells and high-temperature solid electrolyte cells are no longer under major development programs. Two major U.S. programs remain active. One uses methanol as fuel and is aimed first at off-the-road vehicles. The other program, using natural gas reformed to make hydrogen, aims to install some 60, 12.5-KW prototype reformer-fuel cell packages on test in various services.

Capital costs of both of these types of fuel cells will be no less than those of conventional generating plants. Intermediate- and high-temperature fuel cells have neither efficiency nor investment advantages over prospective magnetohydrodynamic-topped or thermionic-topped fossil-fueled or nuclear generating stations.

Some fuel cell types are eliminated from consideration as significant factors in the future energy market by their requirement for high-cost fuel or high-cost electrode catalysts. In the first category are the hydrazine ($1 per pound) air cells of Monsanto and Union Carbide and the many direct hydrogen-oxygen (or air) cells. The high-cost catalyst category includes all of the rest of the low-temperature ($< 200°C$) cells. Intermediate-temperature (600°C) molten-carbonate cells and high-temperature (1,000°C) solid-electrolyte cells avoid expensive fuels and catalysts but present materials and fabrication problems.

The five U.S. companies which have had the largest fuel-cell research and development programs, mostly through government funding, are General Electric, Allis Chalmers, Westinghouse, Esso and Pratt and Whitney.

General Electric successfully developed the H_2-O_2 cell for Gemini. After the completion of the Gemini series, the production facility was shut down. Work on direct oxidation of hydrocarbons was still involved with high platinum loadings at the conclusion of government funding. A small study of catalysts still survives.

Allis Chalmers successfully developed an H_2-O_2 battery for Apollo applications (post-Apollo missions). However, the latter program was cancelled by NASA. Attempts at developing a commercial system with both hydrocarbon and indirect hydrogen fuels were not successful. Further effort has been almost totally cut off.

Westinghouse's high-temperature (1,000°C) solid electrolyte cell used cheap fuel (gasified coal) at high current densities and efficiency and did not require a noble metal catalyst at either electrode. Thus, this system gave promise of having a significant impact in the electric utility area. However, the problems of electrolyte and catalyst stability at 1,000°C have evidently proved too formidable, because funding by the Office of Coal Research has recently been cut off.

The remaining two programs are still active. Esso is using mostly its own money (Esso $7 million and Alsthom $3 million). Pratt and Whitney has received $15 million from the Natural Gas Association for the TARGET* project, aimed at residential gas total energy. Pratt and Whitney is contributing $6 million of its own, with the Institute of Gas Technology (IGT) as a subcontractor. Both of these projects are fairly new, and few technical details have been published. However, the general directions can be surmised from the government research done by both companies.

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* Team to Advance Research for Gas Energy Transmission.

Esso is attempting to develop a direct low-temperature, methanol-air battery. The U.S. program is concentrating on catalyst development, while the company's French partner is working on the hardware. At present, they are using a noble metal catalyst other than platinum but are working on alternatives. They envision a penetration of the off-road vehicle market.

Pratt and Whitney successfully adapted the 200°C molten KOH Bacon cell for the Apollo project. In the commercially oriented TARGET program, there were two approaches. Subcontractor IGT was working on an indirect-hydrogen, molten-carbonate battery, but the work was terminated in early 1971. Pratt and Whitney is working on a low-temperature, indirect-hydrogen, acid-electrolyte battery. The main problems in the first approach were with corrosion and electrolyte stability. In the second approach, which is now receiving all the funding, low-platinum concentrations (less than one gram per square foot of electrode) are being spread on porous supports, and difficulties with slow poisoning and recrystallization must be overcome.

Work has largely ceased on the first three programs (General Electric, Allis Chalmers and Westinghouse). The Esso program selected a modest target (off-road vehicles), but the remaining development problems are substantial. Off-road vehicles account for less than 1 percent of the power consumed for all vehicles (4.5×10^9 KWH out of 600×10^9 KWH in the United States). In the United States, one-third of the off-road vehicles are already electric; in Britain, two-thirds. Therefore, success of the Esso program for off-road vehicles would have small impact on future energy utilization.

Pratt and Whitney has cancelled work on the carbonate cell. The remaining program faces both severe technical obstacles and questions of cost and availability of catalyst. However, Pratt and Whitney has recently shown installed prototypes of their gas-fueled total energy fuel-cell package and has plans to install some 60 identical 12.5 KW prototypes on test in residential and other services throughout the United States. Even if the program is successful, the impact on relative fuel use will be small. Success by 1980, when natural gas will still be relatively plentiful, might shift some electric-power generation from coal or nuclear sources to gas. However, little new gas is expected to be available to utilities on a firm basis beyond that time, and its cost will be relatively high. The efficiency of conversion will be only slightly higher (35 to 45 percent) because of losses in reforming the natural gas and the variable need for waste heat for space heating. Capital costs of fuel-cell generating facilities are not expected to be less than for conventional fossil-fuel or nuclear stations and probably will be several times higher. The most optimistic forecasts place them at about the same level.

Success in development by the year 2000 might be futile in view of dwindling gas supplies. Coal would retain the market, at about the same efficiency, because of losses in the coal-gasification process.

In summary, unless major new developments occur in fuel-cell technology (unlikely, considering the vast amount of work completed), fuel cells will have little impact on fuel utilization by the end of the century. Should reformer types be developed, normal fuel supply economics will determine which fossil fuel is affected. In any case, the gain in fuel efficiency over conventional converters would be small (10 to 15 percent) and would be in competition with expected developments in topping for central-generating stations. A breakthrough in direct use of hydrocarbons or in producing pure fuels such as methanol or hydrazine at low cost might have larger impact on fuel efficiency, but it is not likely that these developments will materialize in the near future.

The following two sections of this chapter--Potential for Central Generation Stations and Fuel Cell Total Energy-- discuss the possible exploitation of fuel cells within the limitations of present and prospective near-term technology.

POTENTIAL FOR CENTRAL GENERATION STATIONS

Among the many types of fuel cells that have been under development in recent years, two types appear particularly suited for use in large central generating stations. These are the molten carbonate cell and the high-temperature solid electrolyte cell. Their suitability derives primarily from their use of non-noble metal or metal oxide electrode catalysts, in contrast to the need for platinum in most other types, and from their ability to use fossil fuels directly.

Using a eutectic mixture of alkali metal carbonates as the electrolyte and operating in the vicinity of 600°C, molten carbonate cells have been extensively developed both in the United States and abroad. Problems remain in materials, fabrication, design and performance of large central station components. Detailed studies have identified these problems and have indicated that prospects are poor for this type of fuel-cell generating station competing economically with steam-turbine plants.[1] Although natural gas could be burned directly in molten carbonate fuel cells, coal would have to be gasified. There is, therefore, no incentive for development from the standpoint of either abundant-fuel utilization or of competitive power cost.

Westinghouse Corporation, under contract by the U.S. Department of Interior, Office of Coal Research (Contract No. 14-01-0001-303), conducted a research and development effort on high-temperature solid-electrolyte fuel cells for central power plants. In this concept, coal would be gasified to feed banks of tubular ceramic fuel-cell elements. Each element would be fabricated from a multiplicity of short, thin-walled segments. Waste heat from the cells would provide heat for gasification.

Figure 22 was developed from an economic analysis that Westinghouse performed for a 200-MW, coal-burning, fuel-cell power plant.[2] This study was bounded by two extremes of material costs for the batteries. The upper bound represents the cost with the most likely battery component materials used. Should the technology of battery design improve, lower-cost materials could be used, and the resulting system power generation cost could be represented by the lower line. The battery fabrication costs used in this study were based on the premise that a manufacturing plant with a capacity of 1,500, 400-watt batteries per hour would be built. Such an assumption is necessary since bench-scale battery fabrication would result in prohibitively high power costs.

The Westinghouse program has been terminated recently because of the withdrawal of funding by the Office of Coal Research. No demonstration plant was built. The economics discussed above are based on tests of bench-scale battery units and a design for the reformer. The reformer was of unconventional design and has not been tested even at bench scale. Major technical problems remain to be solved for the batteries. The electrodes of the high cost version contain noble metal joints whose thermal-mechanical properties do not match well with the zirconium oxide electrolyte tubes which they connect. Means to prevent or avoid spalling are needed. The lower-cost electrodes are metal oxides. They are difficult to apply and tend to evaporate slowly. Battery lifetimes of only a few hundred hours were actually achieved. Scale-up problems are likely to be difficult because of small module size and large plant size. Therefore, although Figure 22 and Table 38 (Chapter 13) show excellent prospective economics for high-temperature fuel-cell power plants, the economics are speculative.

Should the government provide sufficient incentive, more than 10 years and many millions of dollars will be required to develop this fuel-cell concept. The number and nature of the remaining problems suggest that much more laboratory development would be needed prior to a large-scale development program. Availability of funds for coal-fired fuel cells will be in competition for funds allocated to the total coal program, including gasification, liquefaction, ash problems, MHD and stack gas processes. Several among these are further along in development and require current commitment of major funding. In this framework, as a result of the lack of current funding and the many technical problems remaining to be solved, it is not likely that this power plant will be developed.

FUEL CELL TOTAL ENERGY

The intensive development and engineering efforts of the last two decades toward small self-contained fuel cells for space and military applications led naturally to attempts to adapt these devices to broader civilian markets. One obvious market is total energy. Major technological difficulties remained, despite the successful development of two separate fuel cell systems for space flights. The most significant problems in these systems were that only hydrogen or high-energy hydrogenous fuels such as ammonia or hydrazine--all excessively expensive--could be accommodated; cap-

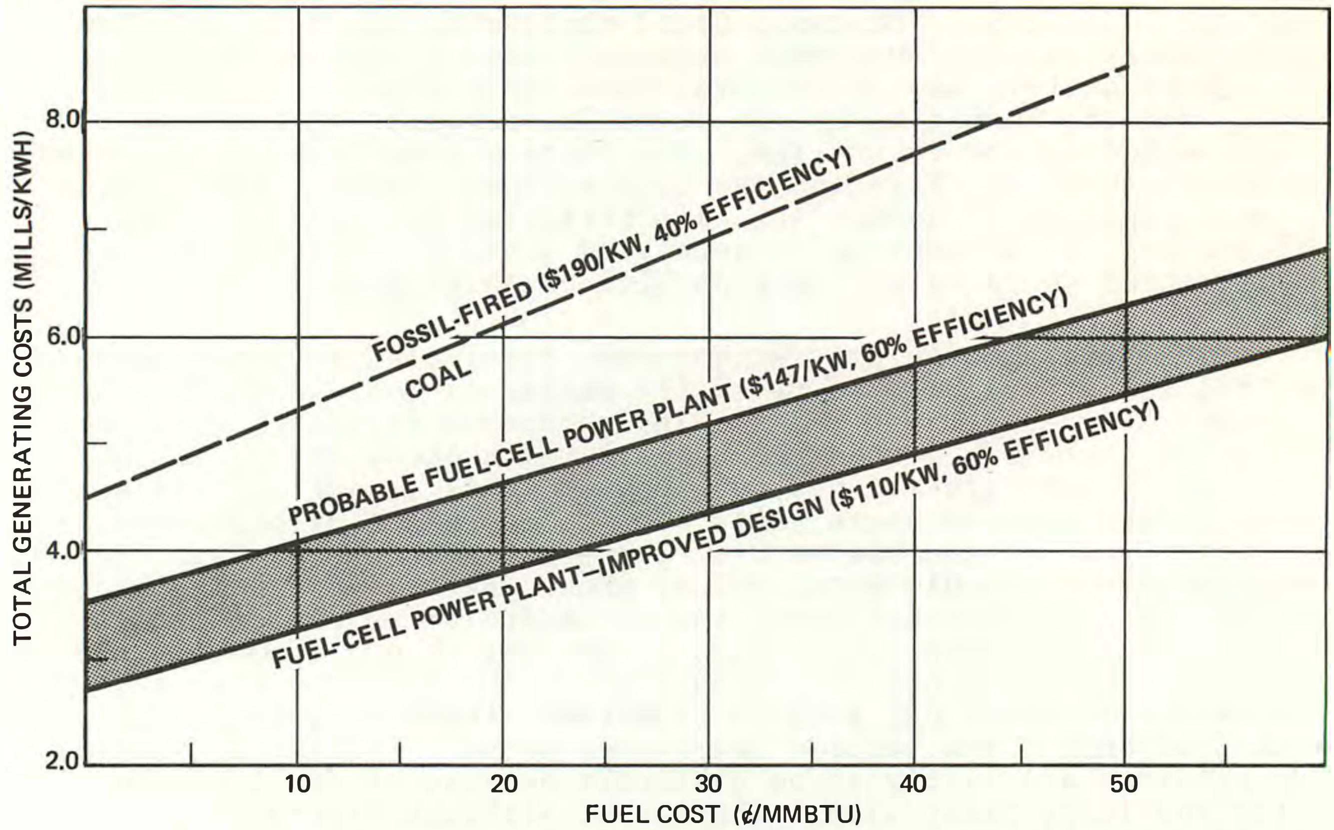

Figure 22. Comparison of Conventional Fossil-Fuel Plant to Fuel-Cell Power Plant (200 MW)

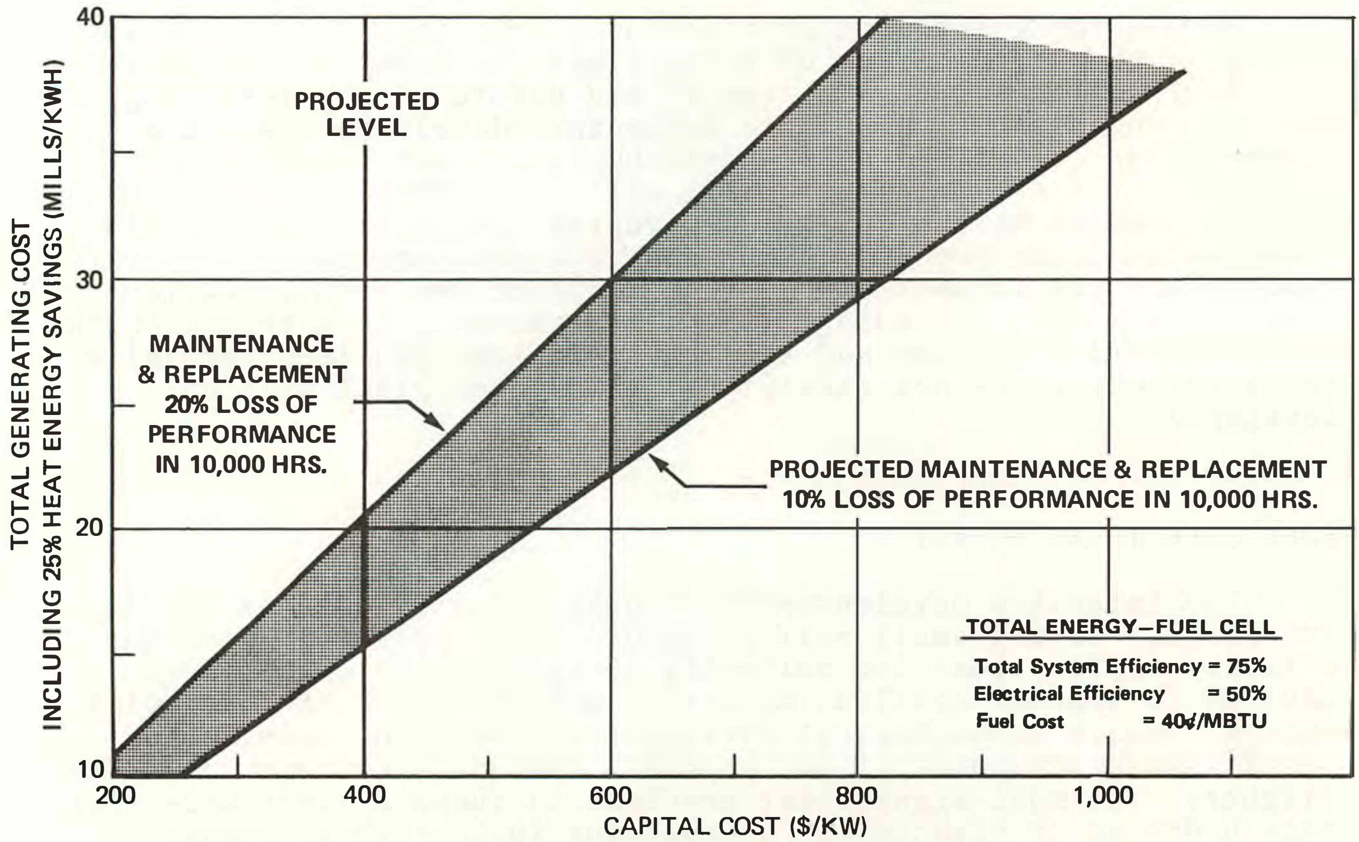

Figure 23. Total Energy--Fuel Cell

ital cost was high; and reliable operation for periods of several years had not been achieved, largely because of catalyst instability.

Federal Government funding of fuel cell development, which supported most of the advanced development programs, recently has been almost totally cut off. Two significant programs are still active, both privately supported.

Pratt and Whitney division of United Aircraft Corporation and 33 natural gas-transmission companies have pooled their resources for the development of an economic fuel-cell total energy system. The group known as the Team to Advance Research for Gas Energy Transmission (TARGET), has recently released some economic projections for their total energy systems. [1] The system includes a catalytic reformer, operating at elevated temperature, to convert natural gas to hydrogen which is then fed to a low-temperature acid-electrolyte fuel cell. The theoretical electrical efficiency is less than that of a pure fuel cell because of the inefficiencies introduced by the reforming reactions. Waste heat recovery, therefore, is expected to be necessary in the TARGET system.

At the present state of art, the TARGET fuel cells use modest amounts of platinum in the electrodes. Most of the performance losses are associated with recrystallization of the finely dispersed platinum. Losses of 20 percent per 10,000 hours have been achieved. The TARGET performance loss is one-half this value. Achieving this will be difficult. Financing of the platinum inventory may require leasing arrangements rather than direct sales. A total of $50 million was committed to the program to the end of 1972. [3] That part of the program will complete field tests of 60, 12.5-KW units in various environments.[1] An additional $50 million may be required to reach the earliest project commercialization date of 1975.

Figure 23 and Table 38 (Chapter Thirteen) indicate that under optimistic assumptions the cost of electrical energy from TARGET fuel cells is, at best, only marginally competitive with delivered central station power. Although the cost of TARGET power is not highly sensitive to natural gas prices, the expected increase in fuel cost will significantly increase the power cost. The use of a scarce fuel for power generation may run counter to public policy. In addition, the gas industry will have to tie up much capital to maintain a large inventory of substitution cell units for recycling every 1 to 3 years. As a result, even though the TARGET system may be successfully commercialized, the prospects of its use becoming sufficiently widespread to significantly affect fossil fuel demand appear negligible.

An alternative fuel cell which operates on methanol might fit the TARGET scheme, although no attempt is currently being made to apply it to total energy. The methanol fuel cell being developed jointly by Esso Research and Engineering and Alsthom (a French Company) is based on technology not very much different from the Pratt and Whitney cell. [2] The Esso cell oxidizes methanol directly and does not require a reformer as does the natural gas system. Hence, it might be cheaper to build. No capital, operation or maintenance data are available. For purposes of comparison, it is assumed here that all economic factors, efficiencies, etc., for the methanol cell version are the same, except the fuel cost. The cost of methanol in 10 to 15 years is forecast as $1.00 per million BTU's. The cost effect of this difference on the projections of Figure 23 is to raise the upper and lower bounds by 0.3 cents per KWH. The total generated power cost in Table 38 is raised by 0.1 cent per KWH. These effects versus the TARGET fuel cell might be compensated by lower capital costs, but further reduction of capital costs to the point of direct competition, even with conventional total energy, would be a considerable achievement.

The Esso methanol cell is being developed currently by industry at a somewhat lower rate ($10 million for the period 1970 to 1975) [3] than that of TARGET ($50 million for the period 1967 to 1972). The basic technology is given in reference. [2] Like the TARGET cell, a noble-metal catalyst (in this case, a platinum-ruthenium mixture) is used.[4] A great deal of the battery development work was done under U.S. Government funding in the 1961-1967 period, but little recent technical data have been made available. If this system were to be developed for total energy, essentially the same possibly insoluble technical and economic problems would apply as mentioned for the TARGET system, and the rate of development would be somewhat slower. The chances of development of this system for total energy are more limited than for TARGET, and commercialization is not likely to occur.

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Chapter Twelve

THERMIONIC POWER GENERATION

Thermionic conversion of heat directly to electricity depends upon the emission of electrons from metal surfaces at very high temperatures--typically near 3,000°F. The electrons are collected on another closely spaced (*ca.* 0.005 inches) metal surface at lower temperature, typically 1,100 to 1,600°F. The device is called a diode, from its close analogy with electronic vacuum tubes. Commonly, the emitter and collector are concentric refractory metal tubes, several inches long. They may be constructed in electrical series connection to multiply the 0.7 to 1 voltage ouput of single diodes. Heat may be supplied by fossil fuels or by nuclear fuels and may be transmitted to the emitter either directly or indirectly, as by a "heat pipe."

Theoretically, efficiencies (electrical output *vs.* thermal input) of thermionic diodes could be as high as 35 to 40 percent with emitter temperatures at or moderately above 3,000°F. To date, the best efficiencies realized in single diodes are about 20 percent. This may rise somewhat. Practically, several additional inefficiencies are introduced by inclusion in a generating system, and system efficiencies do not now exceed about 10 percent. System efficiency is further reduced if the low-voltage DC output must be inverted and transformed to feed an AC power grid, although it is proposed that this can be done very efficiently by acyclic motor-generators. Because of this low efficiency, a large amount of heat must be rejected by the diode. Therefore, interest in large-scale application of thermionic power generation is limited to topping applications, wherein this rejected heat can be productively employed in a steam turbine cycle.

In principle, thermionic topping is feasible in either fossil-fueled or nuclear central generating stations. Considerable progress has been made in shielding emitters from the corrosive and erosive effects of coal combustion products by use of super-refractories based on silicon carbide and nitride. In spite of this, the materials and design problems in coal-fired thermionic systems and in adaptation of boiler systems to thermionic topping, remain formidable. In part because of this, and in part because of competition from more advanced MHD programs and other coal-oriented development programs, coal-fired thermionics has received only modest federal funding. No federal funds, and only small private funds, are currently allocated to this subject.

In that its effect is to increase efficiency in the use of fossil fuels, coal-fired thermionic topping competes with such alternatives as MHD combined-cycle coal plants, and thermionic topping for nuclear plants. The alternatives would provide equivalent fuel economy with somewhat less uncertainty because of their more advanced technological status. Should development nevertheless be deemed desirable, immediate R&D needs would be at a level of several million dollars per year, increasing with time and culminating in construction of a prototype plant. The prototype, if in the range of 100 to 200 MW, would cost upwards of $150 million, and its construction might be possible by 1985.

Thermionic topping of nuclear generating stations is more promising, but its development is at a very early stage. Federal Government expenditures on thermionic conversion, which approximated $8 million per year from 1966 to 1970,[1] are believed to have been directed almost exclusively to use of nuclear fuels and predominately to aerospace applications. Most of the fundamentals and much of the technology developed should be applicable to central station thermionics, as should technology from high-temperature nuclear reactor development. However, difficult problems remain that are unique to thermionics; for example, operational properties of emitter and receptor alloys, electrical properties of insulating refractories, space-charge modification methods, and durability of precisely dimensioned diode assemblies.

Systems design and reliability problems also must be faced. For in-pile thermionic systems, component reliability problems will be aggravated by the fact that essentially all anticipated breakdowns will take place within the reactor and will be inaccessible. Control methods are not yet understood and much development will be needed, although recent digital modeling work indicates that relatively simple controls may be adaquate.[2]

At the current stage of development, power outputs from single diodes are limited to a few hundred watts. Nuclear-fueled elements comprising several "stacked" diodes have produced at least 1 KW. Operating lives of 1 to 2 years have been obtained experimentally. Developmental diodes now cost in the thousands of dollars per KW of output. Materials costs, exclusive of fabrication, are of the order of $300 per KW. Future costs of developed systems have been estimated in the range of $150 to $400 per KW. One specific estimate[3] indicates that thermionic power production capital costs may decrease over the next 10 years from a probable present $1,000 per KW-level to $200 per KW as a result of design improvements.

An economic evaluation of thermionic topping in a 1,000-MW nuclear power generating facility was performed. The power generated by the thermionic topping was assumed to be an additional 250 MW in one case and 500 MW in the other. The advantage of thermionic topping would be in increasing the overall plant efficiency by as much as 15 percent. The economic analysis, summarized in Figure 24, assumed that the operating and maintenance costs for the thermionic portion of the plant would be the same as those of a typical modern-day nuclear plant--i.e., 0.3 mills per KWH.

Figure 24 indicates that the addition of thermionic topping is not economically advantageous unless capital costs per KW approach the most optimistically low levels. This reflects the low dependence of generated power cost on cost of nuclear fuel. There would be other advantages. Fuel recycling and radioactive waste disposal problems would be reduced. Thermal pollution per KWH would be reduced by as much as one-third and, concomitantly,

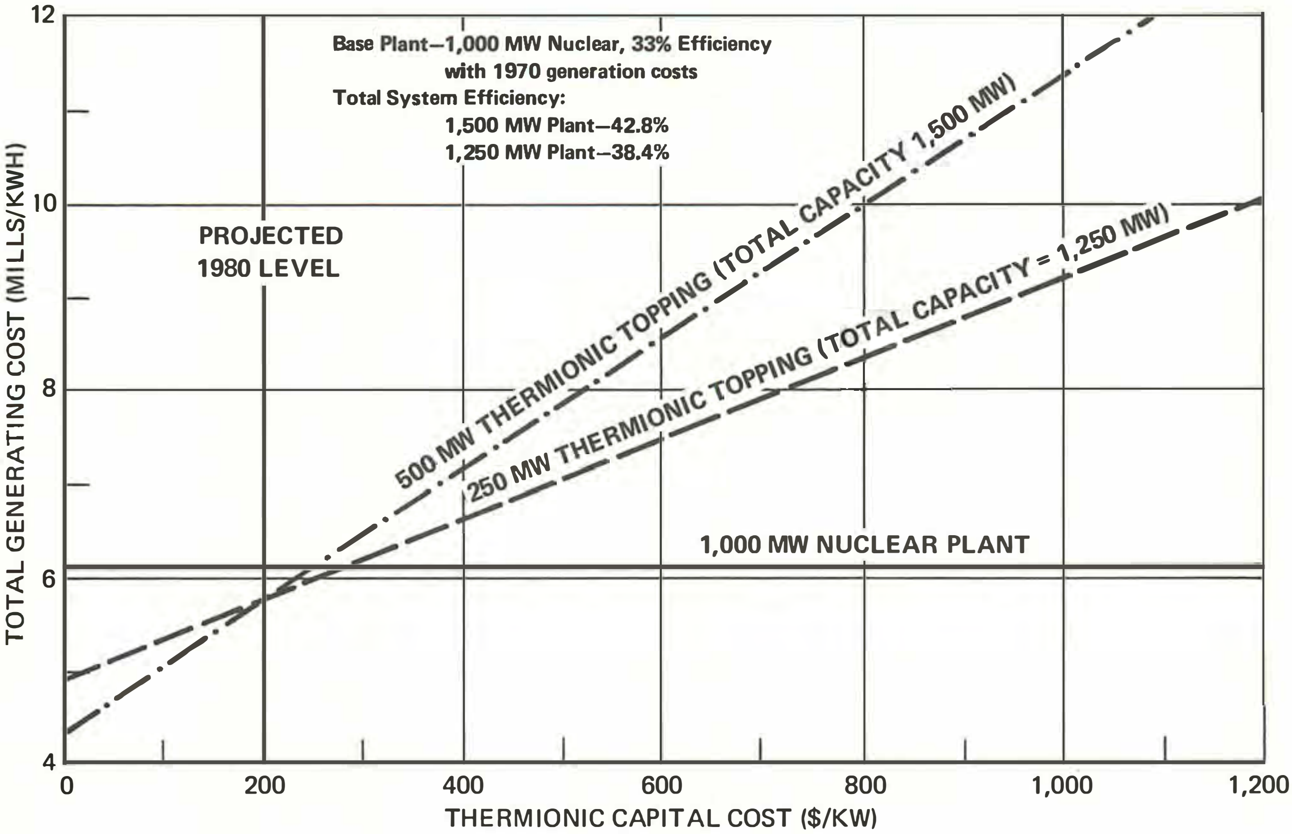

Figure 24. Thermionic Topped Nuclear Plant.

so would investments and operating costs of heat rejection facilities not included in present-day generation costs.

A crash development program might permit construction of a demonstration plant by 1980.[3] The estimated total cost would be several hundred million dollars. As a matter of policy, however, nuclear thermionic topping must be compared to the breeder reactor. From the standpoint of national priorities, the latter seems clearly to be the more urgent. Nuclear thermionic topping must also compete for development funds with methods of improving thermal efficiency in fossil-fueled plants, including MHD. To the degree that it can improve the efficiency, ultimately, of breeder as well as conventional nuclear reactors, and may conserve both nuclear fuels and (indirectly) fossil fuels, thermionics may be competitive, but it might be judged to be of lower priority than direct conservation of coal resources. Since the physical configurations and operating conditions of commercial breeder reactors may be substantially different from those of present nuclear reactors and are not as yet well determined, a strategy of deliberate low-priority development has considerable attraction.

If a long-range development program were adopted for thermionic nuclear topping, on the order of 15 to 20 years to a demonstration plant, substantial economics and efficiencies might be realized by entering into cooperative agreements with overseas development programs. This would avoid duplication of effort and would permit concurrent testing of alternatives. Both the French and West

German governments are supporting development programs in nuclear thermionics. Both aim first at compact unattended thermal reactors, as for space missions, but both include engineering programs relevant to central station topping systems.[4-6]

As a preliminary to any major long-range program planning for the development of thermionic nuclear central station topping, there appears to be a need for a coordinated engineering study of its potential compatibility and economics with respect to the several established types of nuclear generating stations and with prospective types of breeder reactors, and of the relative economic and environmental consequences of its development in comparison with those of such logical alternatives as MHD and solar power conversion.

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Chapter Thirteen

ECONOMIC PROJECTIONS FOR ADVANCED POWER GENERATION SYSTEMS

The following figures summarize the economic forecasts for particular power generation uses of MHD, fuel cells, thermionics and total energy. The information used to develop these curves was obtained from recent publications and announcements by those involved in the development of these devices. The curves thus represent an "educated guess" as to the probable capital, operating and fuel costs for complete power generation plants using each of these conversion techniques in a particular manner. In the case of MHD, thermionic conversion and fuel cells, the values used are subject to successful completion of numerous unresolved development difficulties.

In all cases, except one, the economic evaluation has been based on 15-percent annual capital recovery and an 80-percent plant capacity factor. In the case of the MHD peaking plant evaluation, a 17-percent annual capital recovery was used. A capital recovery factor of 15 to 17 percent is commonly used in power plant economic evaluation.

MAGNETOHYDRODYNAMICS

Figure 25 was developed from information presented to the Electric Research Council Task Force on MHD on May 7, 1970, by Avco Everett Research Laboratory personnel.[1] Avco, in conjunction with a group of leading public utilities and in certain specialized areas with the Department of Defense, has been involved with MHD development for a number of years. An economic analysis was performed on a nominal 1,000 MW direct coal-fired, MHD-topped power plant. The plant design was bounded by presently available engineering techniques ("first generation") and also by foreseeable but more advanced technology ("advanced"). Of the 1,000-MW capacity, about 50 percent it generated by the MHD operation in the first generation plant; while in the advanced, 66 percent is generated by the MHD topping.

Avco has also performed an economic evaluation for a stand-alone MHD peaking plant.[2] Such a plant, even in an advanced design, would have a low efficiency of about 20 percent. However, it would have the advantage of being able to start in less than 5 seconds. It has the further advantage, necessary for any peaking plant, of low capital cost. The particular unit that Avco chose to evaluate has a 400-MW capacity and is fueled with No. 6 fuel oil and liquid oxygen. Figure 26 presents a comparison of this unit's cost relative to more conventional systems.

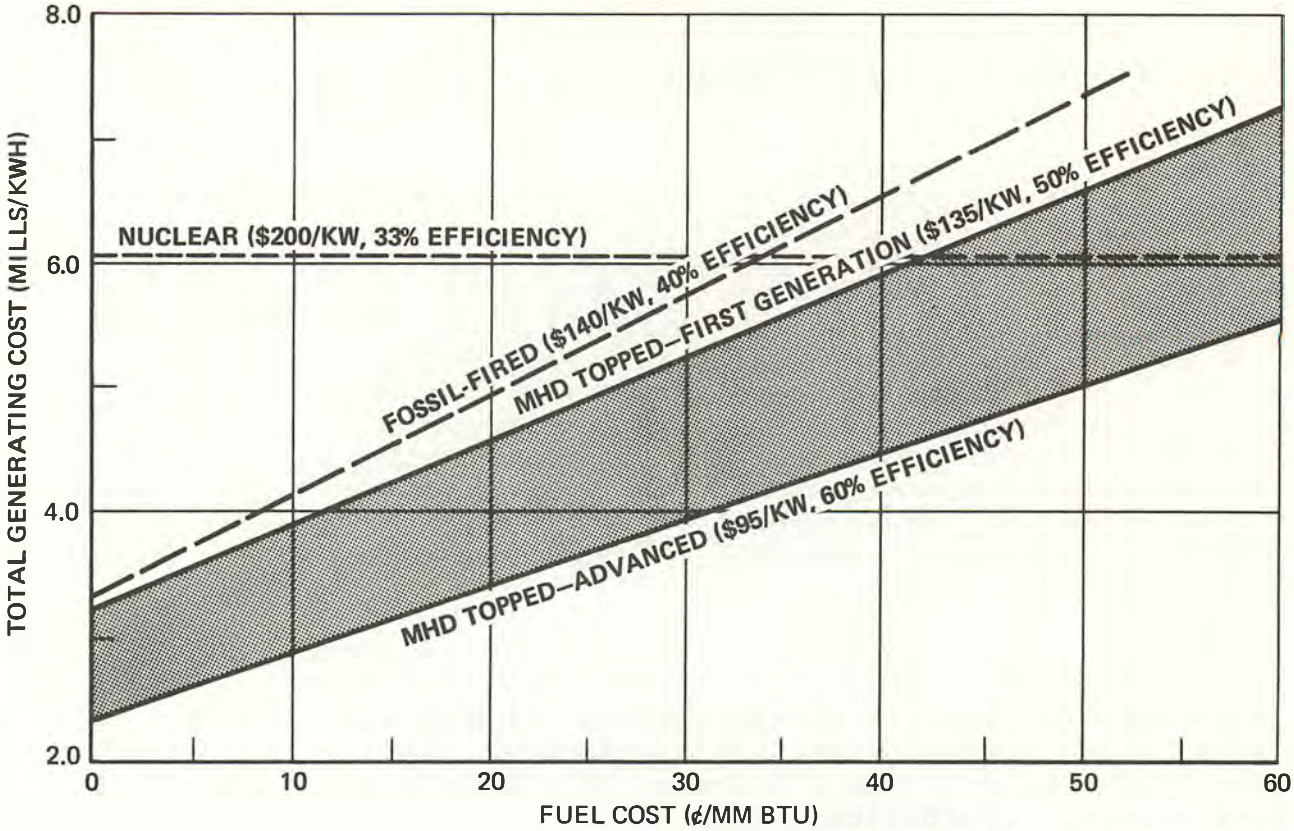

Figure 25. Comparison of Conventional Plants to Combined MHD-Steam Plant (1,000 MW).

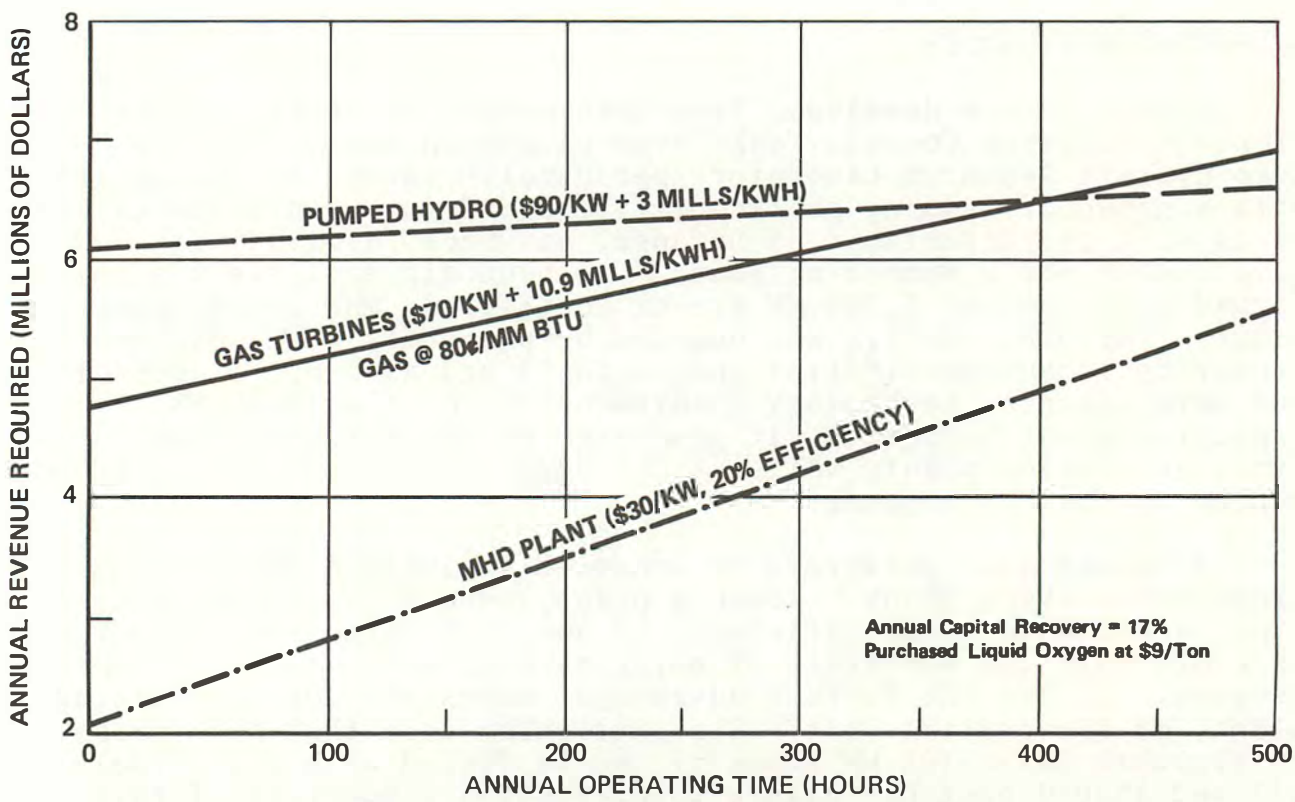

Figure 26. Cost Comparison of a Developed 400-MW MHD Peaking Plant with Conventional Types.

FUEL CELLS

Westinghouse Corporation, under contract by the U.S. Department of Interior, Office of Coal Research (Contract No. 14-01-0001-303) conducted a R&D effort on fuel-cells for central power plants. Figure 22 was developed from an economic analysis that Westinghouse performed for a 200-MW, coal burning, fuel-cell power plant.[3] The study was bounded by two extremes of material costs for the batteries. The upper bound represents the cost with the most likely battery component materials used. Should the technology of battery design improve, lower cost materials could be used and the resulting system power generation cost could be represented by the lower line. The battery fabrication costs used in this study were based on the premise that a manufacturing plant with a capacity of 1,500, 400-watt batteries per hour would be built. Such an assumption is necessary since bench-scale battery fabrication would result in prohibitively high power costs.

THERMIONIC DIODES

An economic evaluation of themionic topping in a 1,000 MW nuclear power generating facility was performed. The power generated by the thermionic topping was assumed to be an additional 250 MW in one case and 500 MW in the other. It has been estimated that thermionic power production capital costs will decrease over the next 10 years from their probable present day level of $1,000 per KW to $200 per KW as a result of design improvements leading to decreased fabrication and material costs.[4] The advantage of thermionic topping would be in increasing the overall plant efficiency by as much as 15 percent. The economic analysis, summarized in Figure 24, assumed that the operating and maintenance costs for the thermionic portion of the plant would be the same as those of a typical modern-day nuclear plant--i.e., 0.3 mills per KWH.

TOTAL ENERGY

The desirability of total energy systems is very much dependent on the particular needs of the power user involved. Factors such as relative amounts of power and steam required and how these requirements vary with time are important considerations for the individual installation. Thus, an economic analysis of total energy was carried out on a particular, fairly typical, 450-KW natural gas-fueled system. The electrical power generating efficiency was assumed to be 30 percent.[5] Figure 16 indicates the effect of fuel cost and waste heat utilization on the cost of power generated by this $100,000 capital cost, 450 KW, gas reciprocating, total energy system. This figure would indicate that if all the recoverable waste heat can be utilized (45 percent of input power), at today's gaseous fuel cost of about 40 cents per million BTU's, purchased power costs would have to be about 13 mills per KWH or higher to result in an economic incentive to in-

TABLE 38

COMPARISON OF PROJECTED ENERGY CONVERSION DEVICE POWER GENERATION COSTS WITH THOSE OF PRESENT DAY THERMAL POWER PLANTS

Plant Description	Conventional	Nuclear	MHD-Topped Steam	High Temp. Coal-Fired Fuel Cell	Thermionic Topped Nuclear	Conventional Total Energy	Fuel Cell Total Energy
Fuel Type	Coal	Enriched Uranium	Coal	Coal	Enriched Uranium	Natural Gas	Natural Gas
Generating Capacity, MW	1,000	1,000	1,000	200	1,000	450 KW	12.5 KW
Efficiency, %	40	33	60	60	48	75*	75†
Capital Cost, $/KW	140	200	95	110	200‡	220	400
Total Generating Cost, Mills/KWH	5.38	6.08	3.74	4.09	6.04	15.42	17.66
Capital Charges, % Total	55	70	55	57	78	31	49
Fuel Cost, % Total§	40	25	38	35	17	33	23
Operating and Main., % Total	5	5	7	8	5	36	28

* 30% electrical + 45% waste heat recovery.

† 50% electrical + 25% waste heat recovery.

‡ Capital cost for thermionic topping portion of the plant.

§ Coal and natural gas fuel costs were assumed to be 25¢/MM BTU at mine-mouth and 80¢/MM BTU, respectively, in about 10-15 years. Fuel cost for total energy included recovered heat energy savings.

stall this 450-KW total energy system. This analysis used an annual capital recovery factor of 15 percent.

The TARGET group has recently released some economic projections for their fuel-cell total energy systems.[6] Figure 23 (Chapter Eleven) is based on these projections for capital costs and maintenance costs. In the development of this curve, it was assumed that the electrical system had an efficiency of 50 percent and that one-half of the waste heat could be recovered as steam and put to use. The lower bound in the figure reflects the design maintenance and replacement criterion of 10-percent loss of performance in 10,000 hours of operation--i.e., for a capital cost in 1970 dollars of $400 per KW, the annual maintenance and replacement cost would be (24 x 365/10,000) (.1 x 400)=$35 per KW. The upper bound indicates the effect, should there be a 20 percent loss of performance in 10,000 hours.

Table 38 summarizes the cost effects for each of the previous five power production systems. It presents the relative capital fuel and operating costs for the plants as projected for advanced designs. Values for present-day nuclear and fossil-fueled plants are listed for comparison. Note that a coal cost of 25 cents per thousand BTU was used as the projected value for mine-mouth coal in 10 to 15 years, while natural gas cost was assumed to double its 1972 cost to about 80 cents per thousand BTU's.

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Part Four

Alternative Usable Energy Forms

Chapter Fourteen

METHANOL AND HYDROGEN

METHANOL AND HYDROGEN FROM COAL

Summary

The manufacture of pipeline gas from coal was analyzed by the Coal Task Group. That analysis was directed at the conversion of coal to an essentially methane-rich gas suitable for substitution with natural gas. However, it is possible to manufacture other energy forms from coal, such as hydrogen and/or methanol (methyl alcohol). This analysis of trends in the technology of converting coal to methanol and hydrogen is included here to indicate the feasibility of utilizing these energy forms as fuels for transportation and other needs as alternatives to petroleum liquids and natural gas.

In general, the costs of methanol from coal are likely to be less if methane and methanol are produced in the same plant as co-products. Costs of coal-derived methanol appears to be in the range of $1.50 to $2.00 per million BTU's, based on the use of modern technology. These costs are likely to be competitive with gasoline from petroleum as petroleum becomes short in supply, when compared strictly on a BTU-basis.

The case used here for a methane facility based on Western coal at 25 cents per million BTU's, and using existing Lurgi technology, yields a relative methane cost of $1.24 per million BTU's. The costs for hydrogen and methanol are on the order of 25 to 30 percent higher than methane for all cases studied.

Discussion

All of the major coal gasification processes now under development will produce gas which can be suitable for either hydrogen production or methyl alcohol manufacture in addition to methane. This can be realized when it is noted that many of the process units and off-site requirements are common to all of the three products as shown in Table 39.

Only trace amounts of carbon monoxide are typically methanated in the manufacture of hydrogen. Plants for manufacturing mixed product slates of methane, hydrogen and methanol could come into being after about 1980 because of this processing similarity.

Starting with any given coal it should be possible to make a variety of products suitable as new energy forms, either with existing technology or with improved technology now under development. Products could be--

TABLE 39

COAL CONVERSION PROCESS STEPS

Process Steps	Substitute Pipeline Gas	Hydrogen	Methyl Alcohol
Coal Handling	X	X	X
Gasification	X	X	X
Oxygen Plant	X	X	X
Water-Gas Shift	X	X	X
Gas Purification	X	X	X
Sulfur Recovery Plant	X	X	X
Power Production	X	X	X
Steam Production	X	X	X
Hydrogenation to Alcohol	–	–	X
Compression	X	X	–
Water Removal	–	–	X
Methanation	X	X (minor)	–

- Methane
- Methanol
- Hydrogen
- Hydrogen-carbon dioxide mixtures
- Methane and methanol
- Methane and hydrogen
- Hydrogen and methanol
- Methane, methanol and hydrogen
- Methane-hydrogen mixtures
- Hydrogen-carbon monoxide mixtures.

In general, it can be said that the costs for manufacturing these products will be in the same range, in that the processing is remarkably similar starting from coal. Some cost differences will occur due to variations in process units, overall thermal efficiency of the coal conversions and relative cost differences in handling the variable energy-content gases.

Assumptions and Methodology

Because of the similiarity in processing requirements, it is possible to generally treat the costs for manufacturing this variety of products with the following parameters:

- Capital requirements ($/MM BTU/day)
- Coal cost (¢/MM BTU)
- Thermal efficiency
- Other operating costs (¢/MM BTU).

Many of the steps are so identical or sufficiently similar that it is possible to estimate the processing complexity, and thereby the capital requirements per unit of energy produced for the several energy forms. This is shown through the following analysis.

The existing Lurgi process for the manufacture of synthetic pipeline gas from a typical sub-bituminous coal is taken as a base case. Capital requirements of the planned El Paso plant in New Mexico using the Lurgi process are about $1,200 per million BTU's per day, with an overall cold gas thermal efficiency of 68 percent.

Methane is a more concentrated energy form than hydrogen and carbon monoxide per unit of volume, such that the size of the reactor vessels for contacting, scrubbing and reacting methane-rich gases would tend to be smaller. The handling of hydrogen-carbon monoxide mixtures, as would be necessary in manufacturing hydrogen or methanol, would call for more voluminous vessels per unit of energy flow. For some of the equipment, this would mean that capital costs per unit of energy would be higher for an operation where the end product is hydrogen. High energy losses would mean that more coal would have to be gasified per unit of energy produced.

Additional qualitative degrees of plant complexity and the estimated capital requirements per unit of energy flow for plants to be built during the 1972-1982 period are shown in Table 40. The capital requirements for manufacturing hydrogen from coal noted in that table agree quite well with the more detailed analysis made by the Coal Task Group. It should be cautioned that it is assumed in this analysis that both methane and hydrogen are made at a final pressure of about 750 psig. If hydrogen must be compressed to 3,000 to 4,000 psig, as for use in a coal liquids hydrogenation plant, the overall capital requirements would be higher and the thermal efficiency of the plant would be somewhat less. To some extent, various costs can be interchanged; for example, a more

TABLE 40

PLANT CAPITAL REQUIREMENTS

Energy Form and Process	Qualitative Plant Complexity (Process Units)	Capital Requirements per Unit of Energy Flow
Methane Manufacture— Thermal Efficiency, 68%	Mod. Temp. Coal Gasification Mod. Oxygen Requirements Mod. Steam Requirements Mod. Compression Requirements Mod. Purification Small Plant Size per Unit Energy Flow Extensive Sulfur Removal	\$1,200/MM BTU/day
Carbon Monoxide— Hydrogen Manufacture (Methanol)— Thermal Efficiency, 50%	High Temp. Coal Gassification Mod. Steam Requirements High Oxygen Requirements Mod. Purification Mod. Plant Size per Unit Energy Flow Methanol Catalysis Methanol Purification	\$1,600/MM BTU/day
Hydrogen Manufacture— Thermal Efficiency, 50%	High Temp. Coal Gasification High Oxygen Requirements High Steam Requirements Multiple Shift Stages Extensive Sulfur Removal Large Plant Size per Unit Energy Flow	\$1,600/MM BTU/day
Methane Methanol Manufacture Thermal Efficiency, 60%	Plant 1 Requirements plus Gas Separation Methanol Catalysis Methanol Purification	\$1,400/MM BTU/day

thermally efficient plant which consumes less coal could be constructed by using more capital dollars. The optimum economic blend of costs would to some extent depend on the local situation. To a very large degree, however, the thermal efficiency in coal processing is fixed by the fundamental laws of chemistry.

With the additional parameters of (1) coal cost, (2) operating costs and (3) total charges on capital, the approximate costs of the various energy forms from coal is fairly well fixed. Additional assumptions such as the following are made:

- Total of capital-related charges; insurance, property taxes, depreciation, interest, income taxes and return assumed to be 20 percent per year
- Annual operating factor of 90 percent
- Completely self-sufficient refinery or total-energy complex based on coal
- No other products such as char, fuel oil, etc.,are produced.

Comparison of Methanol, Hydrogen and Methane from Coal

Based on the above assumptions, a number of economic cases have been roughly estimated for coal-based methanol and hydrogen. These are shown in Table 41. Ranges of coal costs are from 20 cents per million BTU's to 60 cents per million BTU's. This represents extremes of Western sub-bituminous coal at about $3.50 per ton to Eastern bituminous coal at $15.00 per ton. These costs are in the ranges that were estimated by the Coal Task Group for the pre-1985 period.

Costs for methanol and hydrogen are about 30 percent higher than methane, primarily due to the lower product energy flow per unit of coal charged, lower energy content of processed gas and the higher plant complexity.

While these costs may seem higher than many that are presented in the technical literature, the costs are nonetheless thought to be accurate. The El Paso Coal Complex in New Mexico will result in pipeline gas at the plant gate of $1.21 per million BTU's, for example. This simplified analysis (see Table 41) showing about $1.24 per million BTU's for methane from Western coal is approximately in agreement.

The important factors for coal-derived energy forms are costs of mined coal and how the capitalization is handled from an accounting point of view. In general, cost variations in mining different grades of coal are likely to be about as large as the variations in various process improvements which might evolve over the years.

It has been allowed that improved technology in coal gasification processing may be possible about 1979. This would mean that an alternative to the Lurgi process could be commercial about 1982. It has been assumed that improved technology could result in a reduction in capital requirements of about 10 percent or from $1,200 to $1,100 per million BTU's per day.

In general, improved technology in gas processing, larger gas-handling trains, cryogenic and sieving separation techniques

TABLE 41

ECONOMICS OF COAL CONVERSION

Starting Material	Product Slate	Coal Cost (¢/MM BTU)	Thermal Efficiency (Cold Product)	Capital Requirements ($/MM BTU/day)	Energy-Related Costs (¢/MM BTU)	Operating Costs (¢/MM BTU)	Capital-Related Costs (¢/MM BTU)	Total Cost of Product (¢/MM BTU)
1975-1982 Technology								
Base Case								
Western Coal	Methane	20	68%	1,200	29	22	73	124
Western Coal	Methanol	20	50%	1,600	40	22	97	169
Western Coal	Hydrogen	20	50%	1,600	40	24	97	161
Eastern Coal	Methane	50	68%	1,200	74	22	73	169
Eastern Coal	Methanol	50	50%	1,600	100	22	97	219
Eastern Coal	Hydrogen	50	50%	1,600	100	24	97	221
1982-2000 Technology								
Western Coal	Methane	25	70%	1,100	36	20	67	123
Western Coal	Methanol	25	52%	1,400	40	20	85	145
Western Coal	Hydrogen	25	52%	1,400	46	22	85	153
Eastern Coal	Methane	60	72%	1,100	83	20	67	170
Eastern Coal	Methanol	60	52%	1,400	94	20	85	199
Eastern Coal	Hydrogen	60	52%	1,400	109	22	85	216
1975-1982 Technology								
Western Coal	Methanol/Methane	20	60%	1,400	33	22	85	140
1982-2000 Technology								
Western Coal	Methanol/Methane	25	60%	1,300	42	20	79	141
Eastern Coal	Methanol/Methane	60	62%	1,200	97	20	73	190

are likely to have just as significant an effect on cost reductions as is an improved coal gasification reactor. Coal gasification is only a small fraction of the capital requirements of a coal-processing complex, and it is unlikely that dramatic capital cost reductions are possible through any of the new gasification schemes which are now being developed. It has been allowed that some improvement in thermal efficiency will be possible through improved technology. However, these improvements are expected to be slight, of the level 2 to 3 percent in absolute thermal efficiency. These constraints are largely fixed by the relative lack of hydrogen in coal and the necessity of burning a part of coal to convert additional parts to hydrogen.

The operating cost reductions of a coal processing complex should parallel any capital cost reductions. In general, the operating costs represent wages and salaries of operating, maintenance and overhead personnel. It is estimated that perhaps a 2-cent per million BTU's reduction would be possible through improved processing. The total savings on the cost of the products through improved processing should be in the range of 10 to 15 cents per million BTU's.

Most of the economic analyses of coal gasification processes which appear in the technical literature appear to give costs on the low side, and cannot be an objective basis for estimating the costs of various energy forms produced from coal. The costs for coal handling, waste handling, water, steam, and power requirements, waste water treatment, general utility requirements, plant piping and gas purification processing do not seem to be high enough in many of the papers or concept studies in the technical literature. Since many of the gasification processes have not been adequately developed to the point of being analyzable economically, the cost range projections in Table 41 should represent approximate goals for the new technology.

If a mixed product slate is manufactured from coal, such as methane and methanol, the capital requirements per unit of total energy produced are likely to be somewhat less than in the manufacture of each product separately. This may be deduced from Table 39. The principal reasons for cost savings are due to the integration of coal handling and gasification, utilities and offsites and the integration of compression, gas handling and cleanup process equipment; savings in energy are possible in that intermediate and low pressure steam, as well as gas expansion energy, can be used more judiciously throughout the plant.

The high costs for coal-derived energy must necessarily remain indefinitely since coal handling, gas handling, processing, scrubbing and compression are far more capital intensive than the handling of hydrogen-rich liquids such as petroleum. It is fundamentally incorrect to believe that capital requirements for producing gaseous energy forms from coal can ever be reduced to levels which are typical for refining liquid petroleum fractions.

The costs analyzed in this section are plant gate costs. Costs for transportation, marketing and general storage would be in addition to those shown.

HYDROGEN BY WATER ELECTROLYSIS

Summary

A brief analysis was made to examine the conditions under which hydrogen made by water electrolysis could be competitive with hydrogen made from coal. Electrolytic hydrogen cannot be made at costs comparable to costs of synthetic fuels from coal unless low cost electric power is available. Based on the projections of other task groups for the costs of coal and capital requirements for power plants, bus bar rates of electric power can be estimated to be in the range of 9 to 11 mills per KWH for the 1975-1990 period. Even if the breeder is perfected after 1990, it is doubtful that bus bar power costs can be significantly reduced below the range of 9 to 11 mills per KWH. Therefore, costs of distributed power to large industrial customers should remain in that range. With these power costs, electrolytic hydrogen would clearly be uneconomic as a fuel, since the cost of converted energy itself would be \$4 to \$5 per million BTU's.

General Economics of Electrolytic Hydrogen

The cost of electrolytic hydrogen depends on six economic parameters:

- Cost of electric power
- Cell efficiency
- Capital costs of electrolytic cells and storage
- Annual operating factor for cells
- Credit value for electrolytic oxygen
- Total of capital-related charges; insurance, property taxes, depreciation, interest on money, income taxes and return on investment.

To illustrate the effect of these parameters, a number of cases are summarized in Table 42. The levels chosen for the six parameters are:

- Cost of power (mills/KWH; 2, 10)
- Cell efficiency, based on HHV of hydrogen (KWH/MM BTU; 426, 414, 403)
- Capital costs,(\$/MM BTU/day; \$1,480, \$1,230, \$1,000)

TABLE 42

ECONOMICS—HYDROGEN BY ELECTROLYSIS

Power Costs (Mills/KWH)	Capital Costs ($/MM BTU Hydrogen per Day)	Electrolysis Annual Load Factor (Percent)	Cell Energy Requirements, (KWH/MM BTU of Hydrogen)	Total Capital Factor (Percent)	Capital Costs (¢/MM BTU Hydrogen)	Energy Costs (¢/MM BTU Hydrogen)	Operating Costs (¢/MM BTU Hydrogen)	Credit for Oxygen, ($/Ton)	Selling Price of Electrolytic Hydrogen (¢/MM BTU)
10	1,480	100	426	20	81	426	8	None	515
10	1,480	100	426	15	61	426	8	None	495
10	1,480	100	426	20	81	426	8	9	456
10	1,480	100	426	15	61	426	8	9	436
2	1,480	40	426	20	207	85	8	None	300
2	1,480	40	426	15	155	85	8	None	248
2	1,480	40	426	20	207	85	8	9	241
2	1,480	40	426	15	155	85	8	9	189
2	1,200	40	414	20	164	83	8	None	255
2	1,200	40	414	15	125	83	8	None	216
2	1,200	40	414	20	164	83	8	11	183
2	1,200	40	414	15	125	83	8	11	144
2	1,000	40	403	20	137	81	8	None	226
2	1,000	40	403	15	103	81	8	None	192
2	1,000	40	403	20	137	81	8	11	154
2	1,000	40	403	15	103	81	8	11	120

- Credit value of 100-percent oxygen,($/ton; $0, $9, $11)

- Annual operating factor (100-percent, 40-percent)

- Capital-related charges (15-percent, 20-percent).

The range of power costs represent the extreme low of off-peak power of 2 mills per KWH to the typically low steady state industrial power costs of 10 to 12 mills per KWH expected in 1972 to 1990. Capital requirements of $1,480 per million BTU's of hydrogen per day represent the available 1973 technology for water electrolysis cells and storage tanks. These costs are based on information published in 1968 and have not been corrected to current economic conditions.

If it is assumed that a 20- or 30-percent reduction in capital costs is feasible by 1985, the capital cost parameters of $1,200 and $1,000 per million BTU's of hydrogen per day represents this improved technology. This is regarded as extremely optimistic, however.

Since water electrolysis to make hydrogen also produces oxygen, the economics for hydrogen manufacture depend on whether a credit can be taken for the by-product oxygen. Parameters of $0, $9 and $11 per ton are used.

With current industrial power at 6 to 9 mills per KWH in many parts of the country, 95-percent grade oxygen can be made in air-separation plants for about $9 per ton. If industrial power increases in cost to 10 to 12 mills per KWH in the coming years, it seems reasonable that tonnage oxygen by air separation would be about $11 per ton. This accounts for the range of credits used for by-product 100-percent oxygen in the following cost estimates for electrolytic hydrogen.

Costs for electrolytic hydrogen are highly sensitive to the annual operating or load factor. Values of 40- and 100-percent are chosen. The lower value would correspond to a plant using off-peak power.

Based on these parametric projections (see Table 42) electrolytic-hydrogen will be very expensive based on nuclear-based electric power at 10 mills per KWH. It is clear that even if off-peak power were available as low as 2 mills per KWH electrolytic hydrogen would still not be competitive with synthetic fuels made from coal. If the annual operating factor of the electrolysis cell is as low as 40 percent, costs are even higher for the hydrogen.

As shown in Table 42, a credit for by-product oxygen of $9 per ton has the effect of reducing the hydrogen cost by about $0.59 per million BTU's. However, even with a credit, costs of hydrogen are still about $2.50 per million BTU's using the very optimistic costs of off-peak power at 2 mills per KWH.

It seems clear that the extensive use of water electrolysis to make hydrogen would provide an amount of oxygen which would inundate industrial markets for oxygen. No credit for by-product oxygen is therefore likely in the United States, at least in a general sense.

In summary, costs of electrolytic hydrogen will not be competitive with fuels made from coal in the period before 1985. After 1985, the future of electrolytic hydrogen will depend on breakthroughs that would reduce the cost of electric power. Such electric power cost reductions are not likely with the breeder. Alternatively, ways must be found to bypass the need for electric power in decomposing water with thermal energy.

Chapter Fifteen

ECONOMIC COMPARISON BETWEEN PETROLEUM AND ALTERNATE FORMS

SUMMARY

This section is included to allow a clearer comparison of how coal-derived methanol and hydrogen can compete with conventional petroleum-derived fuels. The task groups associated with development of the reports on oil refrained from any discussion of refined fuels from oil. However, it is impossible to compare methanol and hydrogen derived from coal unless the comparison is made with fuels refined from petroleum. The economic comparison in this section is at the "refinery gate." There is a danger in using these comparisons as properly reflecting prices in the marketplace because the latter will include transportation, storage, marketing costs and other use taxes. Higher handling and distribution costs will prevail for methanol and hydrogen.

The general conclusion is that methanol from coal is competitive at the refinery gate on a BTU-basis with transportation fuel made from petroleum if petroleum approaches $6 to $7 per barrel. This assumes coal availability at 30 cents per million BTU's.

Methanol and hydrogen derived from electric power are not competitive with the same energy forms derived from coal.

GENERAL ASSUMPTIONS AND METHODOLOGY

Conventional refineries manufacture a wide variety of fuels from crude liquid petroleum. However, a simplified analysis of the economics for refining liquid fuels can be made with several parameters, analagous to those used before.

TABLE 43

ECONOMIC ASSUMPTIONS—PETROLEUM

Crude Oil Price, $/BBL

$3.35, $4.00, $5.00, $6.00, $7.00, $8.00

Thermal Efficiency of Refining, (Percent)

1972—91
1985—88

Capital Requirements, $/MM BTU/Day

1972—$250
1985—$350

Annual Operating Factor, (Percent)

90

Operating Costs

1972—10¢/MM BTU
1985—15¢/MM BTU

Total of Capital Charges

Depreciation, taxes, insurance, income tax, interest + return, assumed to be 20 percent

The cost of crude oil (see Table 43) is allowed to vary from \$3.35 per barrel to \$8.00 per barrel, corresponding approximately to price ranges studied by the Oil Supply Task Group.

The capital requirements per unit of energy refined from petroleum in 1972 are approximately \$250 per million BTU's per day. A conventional refinery manufactures a wide variety of fuels from crude petroleum. However, the capital requirements for refining liquid fractions are only a fraction of the requirements for manufacturing gaseous energy forms. The typical U.S. refinery in 1972 employed many relatively low-cost operations such as distillation and catalytic cracking. Some higher-cost operations such as coking, reforming, alkylation, hydrocracking, hydrogenation and hydrodesulfurization are also used. In addition, the manufacture of motor gasolines involves expensive processing steps such as solvent extraction, blending and the use of various additive packages. Costs of making gasoline are considerably higher than costs for distillates and fuel oils.

With the impending need for more water- and air-pollution control, the probable requirement to manufacture more hydrogen, it can be estimated that new refieries in 1985 will require capital corresponding to about \$350 per million BTU's per day. The technological trends to lighter, more hydrogen-rich fuels for gas turbines and Wankel engines, with the added necessity for processing more high-sulfur Middle East crude oils, are additional factors which would require a more capital-intensive petroleum refinery.

If energy self-sufficient refineries only are considered, the overall thermal efficiency is 91 percent in 1972, perhaps decreasing to 88 percent in 1985. The lower efficiency in 1985 is consistent with higher hydrogen requirements for fuels. Annual operating factors for all refineries are assumed to be 90 percent.

Operating costs of about 10 cents per million BTU's are typical of today's large refineries (100 to 300,000 barrels per day), and it is anticipated that this could increase to about 15 cents per million BTU's for the more capital-intensive and environmentally-controlled refinery of the future.

To simplify the treatment of capital charges, a flat annual charge of 20 percent is used. This places the refinery economics on the same relativity of hydrogen, methane and methanol made from coal.

RELATIVE COMPARISONS

Table 44 summarizes average refinery gate costs of liquid energy forms made from petroleum. As noted, the most important factor influencing costs is the cost of the starting crude oil. This is a fundamental point relative to costs for refining liquid energy forms from petroleum. Energy costs represent 70 to 80 percent of the cost of the products; capital and operating

TABLE 44

APPROXIMATE COSTS FOR REFINED LIQUID ENERGY FORMS FROM PETROLEUM
(Basis: Mixed Gasoline/Fuel Oil Refining)

Starting Energy Form	Product Energy Form	Crude Oil Cost ($/Bbl)	Crude Oil Cost (¢/MM BTU)	Capital Requirements ($/MM BTU/day)	Thermal Efficiency (Percent)	Energy Related Costs (¢/MM BTU)	Operating Costs (¢/MM BTU)	Capital-Related Costs (¢/MM BTU)	Total Refinery Gate Energy Costs (¢/MM BTU)
Crude Oil	Gasoline Fuel Oil	3.35	59	250	91	65	10	15	90
Crude Oil	Gasoline Fuel Oil	4.00	69	250	91	76	10	15	104
Crude Oil	Gasoline Fuel Oil	5.00	86	350	91	95	15	21	131
Crude Oil	Gasoline Fuel Oil	6.00	103	350	88	117	15	21	153
Crude Oil	Gasoline Fuel Oil	7.00	120	350	88	136	15	21	172
Crude Oil	Gasoline Fuel Oil	8.00	138	350	88	157	15	21	193

TABLE 45

COMPARISON OF LIQUID AND GASEOUS FUELS FROM CRUDE OIL

Starting Energy Form	Product Energy Form	Crude Oil Cost ($/Bbl)	Crude Oil Cost (¢/MM BTU)	Capital Requirements ($/MM BTU/day)	Thermal Efficiency (Percent)	Energy Related Costs (¢/MM BTU)	Operating Costs (¢/MM BTU)	Capital-Related Costs (¢/MM BTU)	Total Refinery Gate Energy Costs (¢/MM BTU)
High-S Crude Oil	Fuel Oil	4	69	250	92	75	6	15	96
High-S Crude Oil	Methane	4	69	520	80	86	8	32	126
High-S Crude Oil	Fuel Oil	6	103	250	92	112	6	15	133
High-S Crude Oil	Methane	6	103	520	80	129	8	32	169
High-S Crude Oil	Fuel Oil	8	138	250	92	150	6	15	171
High-S Crude Oil	Methane	8	138	520	80	173	8	32	213

costs are a relatively small fraction of costs. As the future cost of crude oil increases, the capital and operating costs of refineries should become a smaller percentage of total costs.

If light complex fuels, as are typical of gasoline are not required products, a relatively simple refinery can be used. For example, if the only product is a sulfur-free liquid fuel oil, processing costs are less than in a complex gasoline refinery. It is estimated that the capital requirements for a refinery (completely self-sufficient in energy and making only a liquid fuel) would be about \$250 per million BTU's per day. This can be compared with the capital requirements of \$520 per million BTU's per day for converting crude oil to gas. A comparison of costs of a liquid and gas made from crude oil are shown in Table 45. As noted, high quality liquid fuels can be made for considerably lower costs than methane.

The cost of liquid fuels made from crude oil depends importantly on the cost of crude oil. The relative competitiveness of methanol from coal depends on the costs of crude oil and coal together with other capital and operating costs.

Figure 27 depicts the costs of methanol derived from coal and the costs of liquid fuels derived from crude oil as a function of primary energy costs. Approximate and comparable economic analyses have been made, following the results shown in previous tables. The fuel oil results are taken from Tables 44 and 45 in this chapter, while the methanol results are taken from Table 41 in Chapter Fourteen.

The following conclusions can be made:

- If coal is 30 cents per million BTU's, the heating value of methanol made from coal will be approximately competitive with liquid fuels made from crude oil when crude oil reaches \$1.10 to \$1.30 per million BTU's. This corresponds to crude oil costs of \$6.40 to \$7.50 per barrel.
- For coal at 50 cents per million BTU's, fuels from crude oil would be lower in cost than methanol providing crude oil was less than about \$8.00 per barrel.

METHANOL FROM NATURAL GAS

Much interest has been developing in the world energy markets for the conversion of methane into methanol. The attraction is that a difficult-to-handle gaseous energy form can be converted to a liquid which can then be more easily handled and transported.

An important trend in recent years is the revolution in cost reductions for methanol manufacture. These cost reductions are due to developments in catalysis, developments in gas turbines for compressing gases and the application of total energy concepts to manufacture methanol.

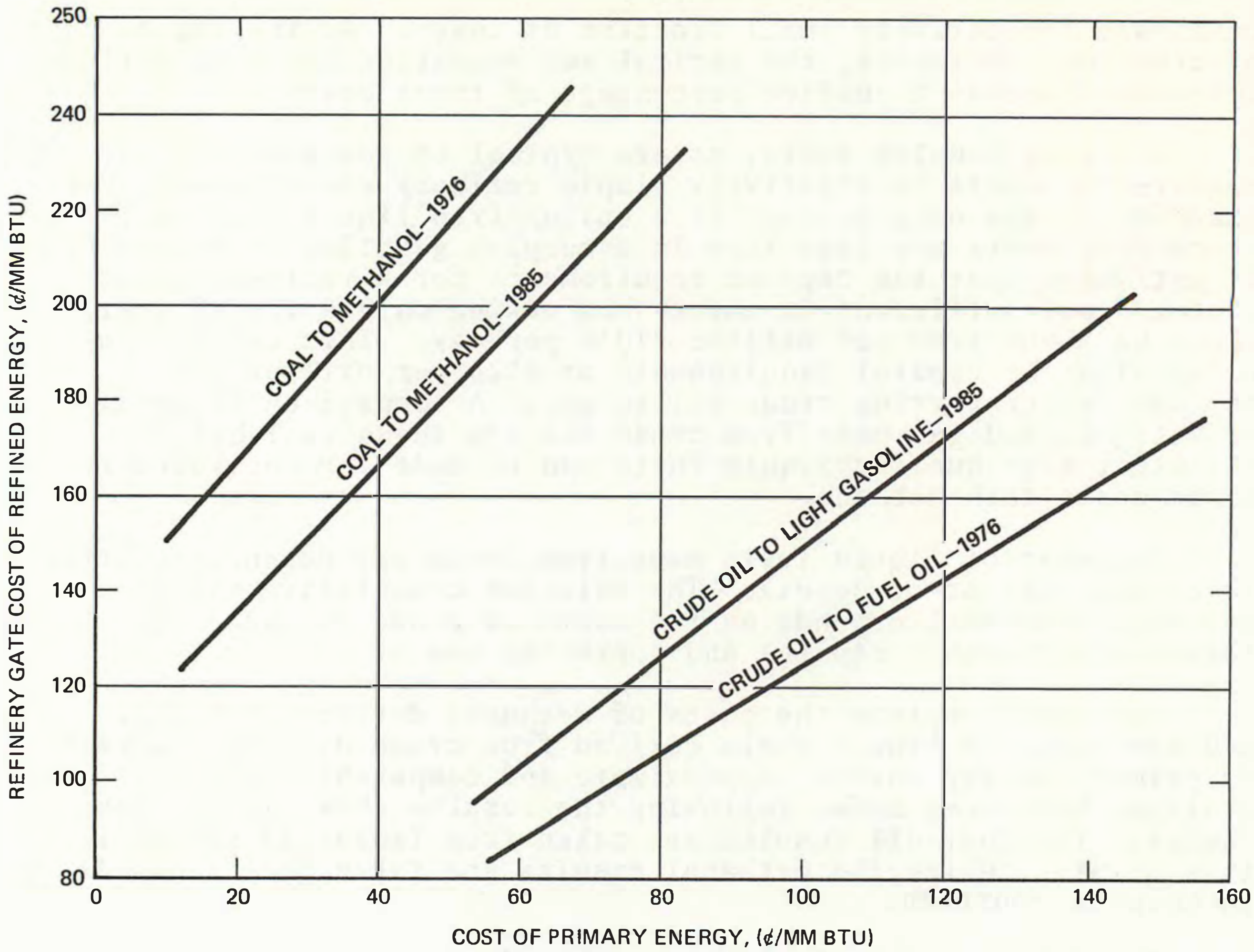

Figure 27. Methanol from Coal vs. Fuels from Crude Oil.

Now, single-train methanol plants can be built which are capable of producing 5,000 tons per day of methanol. This is equivalent to about 100 x 10^9 BTU's of liquid fuel per day, or is 40 percent of the energy output of a large coal gasification plant. Even larger methanol capacity per single train can be projected to the future.

The capital requirements for large methanol plants are now estimated to be about $400 per million BTU's per day. Total costs of producing methanol from natural gas can be estimated by similar procedures used for coal. A summary is shown in Table 46.

As noted by Table 46, the great interest in methanol as a liquid fuel depends on a supply of low-cost natural gas. Other advantages of a liquid fuel are:

- Methanol is a safe, easily transportable and pollution-free energy form.
- Fuel shipment can be in standard tankers avoiding the special high-cost cryogenic tankers for liquid natural gas (LNG).

TABLE 46

ESTIMATED COSTS FOR CONVERSION OF NATURAL GAS TO METHANOL

Starting Energy Form	Product Energy Form	Methane Costs (¢/MM BTU)	Capital Requirements ($/MM BTU/Day)	Plant Thermal Efficiency (Percent)	Energy-Related Costs (¢/MM BTU)	Operating Costs (¢/MM BTU)	Capital-Related Costs (¢/MM BTU)	Total Cost of Product (¢/MM BTU)
Methane	Methanol	10	400	55	18	15	24	57
Methane	Methanol	20	400	55	36	15	24	75
Methane	Methanol	40	400	55	73	15	24	112
Methane	Methanol	60	400	55	108	15	24	143
Methane	Methanol	80	400	55	146	15	24	185
Methane	Methanol	100	400	55	182	15	24	221

A recent analysis has shown that methanol manufacture is about competitive with LNG where the transport distance is about 3,500 miles. Both have a delivered cost of about 74 cents per million BTU's to an East Coast port. As the distance for delivery increases, the manufacture of methanol at the source of available methane begins to look even more attractive relative to LNG. This is because the capital requirements for LNG tankers are 3 to 4 times that of methanol tankers per unit of energy flow.

METHANOL AND HYDROGEN BY WATER ELECTROLYSIS

Ultimately, the cost of producing hydrogen by water electrolysis will dictate the cost of liquid synthetic fuels. As the cost of gas, petroleum and coal increases, it may prove cheaper at some future time to make hydrogen by water electrolysis. Unfortunately, this future time cannot be accurately predicted.

Under some special circumstances, it is now judged that electrolytic hydrogen can be made for costs in the range of \$1.50 to \$2.50 per million BTU's, using off-peak electric power and taking a credit for the oxygen produced (see Chapter Fourteen). However, it is fundamental that synthetic liquid fuels cannot be made in abundance through electrolytic hydrogen unless a breakthrough occurs in reducing the capital costs of power plants. This can be realized when it is noted that the capital cost of nuclear power plants is projected to be about \$400 per KW (electricity) for some time to come. The production of hydrogen can be projected to be about \$100 per KW (hydrogen), while the conversion of hydrogen to a liquid is about \$20 per KW (methanol). With the normal energy losses in the conversion steps, the total capital requirements for methanol from electricity are now about \$845 per KW, with the conversion of nuclear energy to electricity representing 83-percent of the total capital requirements.

Technology is now available which could convert mixtures of hydrogen and carbon dioxide to methanol at capital requirements of \$250 per million BTU's per day, or about \$20 per KW. The thermal efficiency of this operation would be about 80 percent, and operating costs should be about 8 cents per million BTU's of methanol produced. The capital costs would add about 13 cents per million BTU's, using the same 20-percent annual charge which has been used in other comparisons.

However, synthetic fuels cannot be made economically from water unless a breakthrough occurs in reducing the cost of electric power by a factor of about 4. Alternatively, a breakthrough must occur in decomposing water with thermal energy.

SHIPMENT AND LOGISTICS PROBLEMS WITH NEW ENERGY FORMS

Liquids have a fundamental advantage relative to gas in that the energy content per unit volume is considerably higher. This accounts for the fact that costs for manufacturing a liquid are generally lower than for a gas. Also, this advantage for liquids carries over to the shipment and storage of energy. Table 47 summarizes costs for transporting energy in the United States for a distance of 1,000 miles. Large pipelines carrying liquids can deliver energy for about one-third the cost of delivering gas, when comparable economics are applied.

No technology exists for transporting hydrogen and methanol by pipeline. However, estimates have been made for transporting these energy forms mainly based on first principles and engineering judgment.

At a comparable pressure, hydrogen (as a gas) only contains about one-third of the energy of natural gas. For a given pipeline diameter, the hydrogen must be pumped at 3 times the velocity of methane to obtain the same flow-rate of energy. It turns out that the frictional force exerted by the inner wall of the pipe is proportional to the density of the gas multiplied by the square of the velocity. From fundamentals it develops that the frictional force or energy loss per unit of energy transported in a pipeline is about 12-percent higher for hydrogen than for methane. However, because the energy content of hydrogen gas is lower than methane, the compressor stations would have to be larger to handle the energy loss while transporting hydrogen.

The cost for transporting hydrogen vapor is estimated to be about 36 cents per million BTU's for a distance of 1,000 miles. A 25-percent increase in capital costs has been included to allow for slightly larger capacity, a probable need for different alloys and welding techniques and the need for larger compressor stations. It should be stressed that pipeline compressor station size, compressor station spacing, pipeline diameter, wall thickness, pressure and route all tend to have complex economic relationships with respect to distance, energy flow rate and energy cost.

Transportation costs for gaseous energy should begin to increase significantly after about 1976. This relates to the fact that the value of energy moving in pipelines is now quite low. The average is somewhere between well-head prices and so-called city-gate prices, perhaps about 30 cents per million BTU's. If the cost of synthetic gas is $1.20 to $1.50 per million BTU's, energy-related costs for transporting energy could increase by a factor of 3 to 4. However, this will be moderated in the 1976 to 2000 period in that pipelines would be carrying mixtures of lower-cost natural gas and synthetic gas. Also, electric motor-driven compressors would tend to be used in lieu of engine-driven compressors, and this should keep pipeline transportation costs at lower levels than have been indicated as extremes in Table 47. However, it has been estimated that energy costs for moving hydrogen would be about 30-percent higher than moving methane.

There are technical problems in transporting hydrogen by pipeline which may not be satisfactorily solved for some time. The wide flammability limits of hydrogen and easy ignitability by

TABLE 47

RELATIVE TRANSPORTATION COSTS

Energy Form	Transportation Method	Capital-Related Costs (¢/MM BTU)	Energy-Related Costs (¢/MM BTU)	Other Operating Costs (¢/MM BTU)	Total Costs per 1,000 Miles (¢/MM BTU)
Pre-1972 Situation					
Methane	36-42 inch Pipeline	16	2	2	20
Petroleum Liquids	24-30 inch Pipeline	5	0.5	1	6.5
Bituminous Coal	Unit Train	–	–	–	20
1976-2000 Situation					
Substitute Methane	36-42 inch Pipeline-vapor	16	10	2	28
Hydrogen	36-42 inch Pipeline-vapor	20	13	3	36
Methane	Pipeline-LNG	8	3	3	14
Methanol	Pipeline	10	1	2	13
Petroleum Liquids	Pipeline	5	1	1	7

electrostatic sparks may cause more potential hazards than in the shipment of methane. Hydrogen can diffuse through certain metals in the atomic form and leakage may be a problem with conventional welded steel pipe. However, plastic pipe could be used as an alternative. Because the general technical problems for large-scale hydrogen transport have not been extensively studied, it is judged that no significant trend to pipeline hydrogen is likely before 1985.

There are additional problems in the use of hydrogen as a fuel. Its flame speed is about 8 times that of methane, and the potential hazards in widespread use are not now accurately known. Blends of 20- to 25- percent hydrogen in methane are known to be acceptable in most burner applications, however. Synthetic gases made from crude oil and coal will variously contain 4- to 10-percent hydrogen in methane, and the widespread use of these gases may eventually allow greater confidence in using higher hydrogen concentrations.

A number of technical problems must be solved before liquid methane can move as a cryogenic liquid across the United States. However, it is now judged that the shipment of LNG at -150° F can occur with fewer technical problems than the shipment of cryogenic hydrogen at -425°F or cryogenic methane at -320°F.

The principal hazards with methanol relate to its high volatility and high solubility in water. In transportation by pipeline, leaks may well be a hazard to water supplies. However, the selected use of methanol may be quite practical under controlled conditions. Similar controls have been successfully applied to lead additives and the aromatic constituents of gasoline.

No marked interest seems to exist in the use of methanol in the United States. This may be due to the fact that it could not economically compete with petroleum liquids and natural gas in the past. However, interest may begin to quicken as its success as a fuel and its long-term potential are more widely recognized.

Appendices

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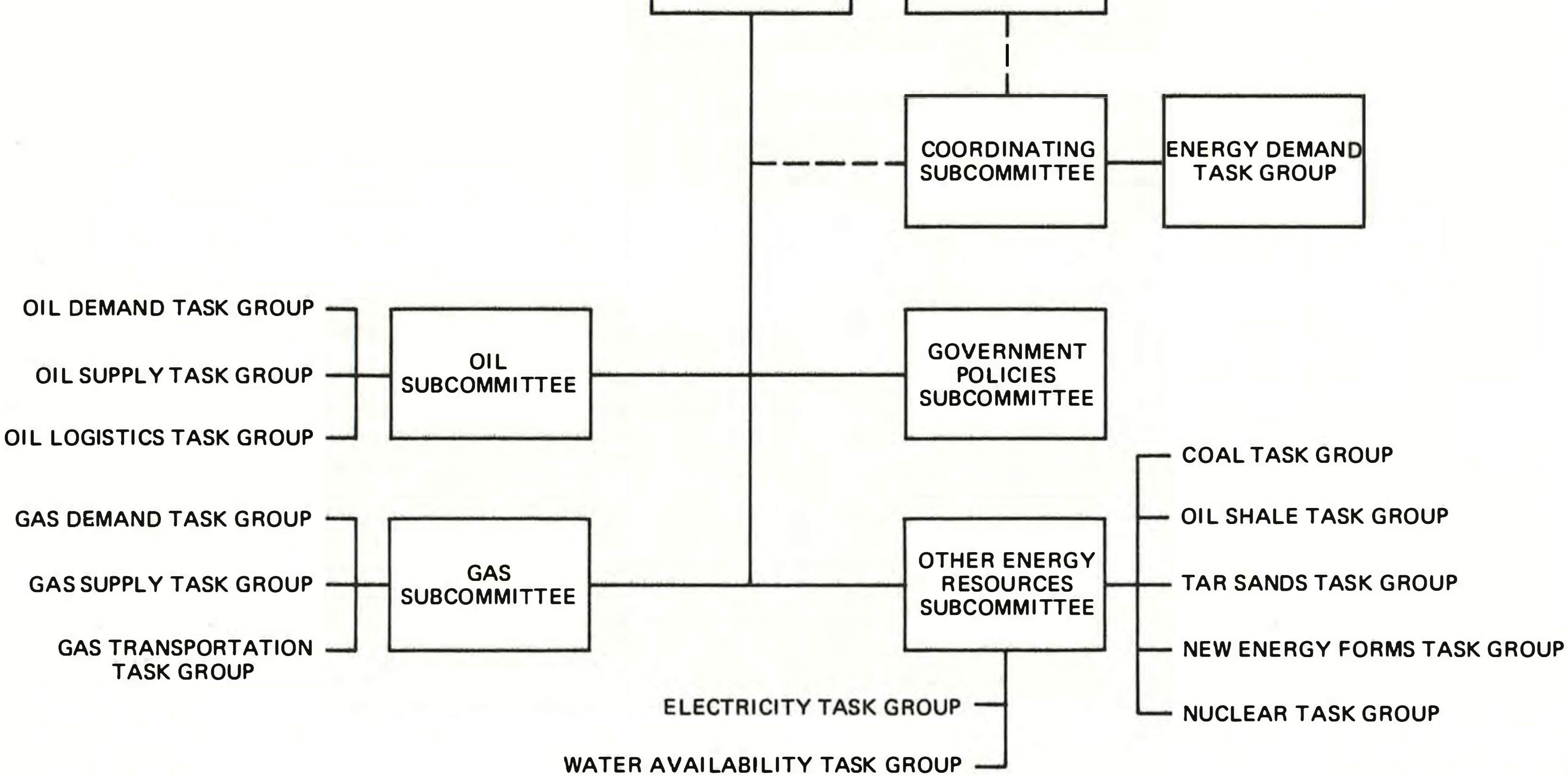

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