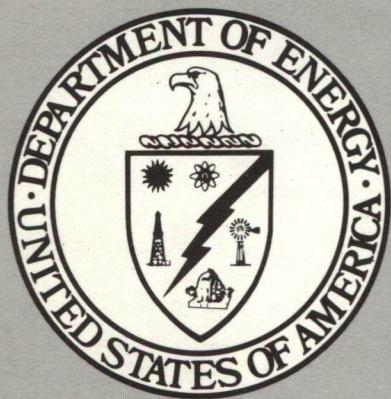


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**GAS REACTOR INTERNATIONAL COOPERATIVE
PROGRAM**

HTR Market Assessments

By
G. Garth Leeth
Ben J. Berkowitz

September 1979

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General Electric Company—TEMPO
Center for Advanced Studies
Santa Barbara, California

**TECHNICAL INFORMATION CENTER
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of

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ACRONYMS AND ABBREVIATIONS

AVR	Arbeitsgemeinschaft Versuchsreaktor GmbH, a 46 MW _e experimental gas-cooled pebble bed reactor at Juelich, West Germany
bbl	Barrels
Bi-Gas	Coal gasification process using combustion of char with oxygen supplied to the gasifier
CCL	Catalytic Coal Liquids process for coal liquefaction
CSF	Consol Synthetic Fuel process for coal liquefaction
CSG	Consol Synthetic Gas process for coal gasification which forms dolomite from carbon dioxide and calcium and magnesium oxides
FBC	Fluidized bed combustor
FGA	Fuel Gas Associates coal gasification process using the combustion and steam gasification of char in reducing gas and steam-iron process for hydrogen production
GW _e	Gigawatts (10 ⁹ kilowatts) of electricity
GW _t	Gigawatts (10 ⁹ kilowatts) of thermal energy
HTR	High temperature gas-cooled reactor
Hygas	Coal gasification process using electro-thermal steam gasification of char with power produced in combined MHD/steam turbine plant fuel by char
LHV	Low heating value
MMBtu	Million British thermal units
Mscf	Thousand standard cubic feet
MW _e	Megawatts (10 ³ kilowatts) of electricity
MW _t	Megawatts (10 ³ kilowatts) of thermal energy
PBR	Pebble bed reactor (type of HTR)
SIC	Standard Industrial Classification
SMSA	Standard Metropolitan Statistical Area
SNG	Substitute natural gas
SRC	Solvent Refined Coal process for coal liquefaction
Synthane	Coal gasification process using the combustion of char with oxygen supplied to gasifier
Synthoil	Process for coal liquefaction

	Tons
TCP	Thermochemical Pipeline, a system which converts the thermal energy of a nuclear reactor into chemical energy by the steam reforming of methane into a mixture of hydrogen and carbon monoxide. The products can be transported and stored by pipeline to remote users who reconvert the gas to produce thermal energy.
TWH	Terawatt-hours (10^9 kilowatt-hours) of thermal energy

ABSTRACT

The HTR Multiplex utilizes the HTR as an energy source to produce multiple forms of energy. The multiplex technology is applicable to the following markets:

- 1) Dispersed industrial heat,
- 2) Peaking and mid-range electricity,
- 3) Ammonia and methanol production with methane feedstock, and
- 4) Production of gaseous and liquid fuels from coal.

It is estimated that the first two markets will comprise from 300 GW_t to 400 GW_t in the 2000 to 2020 time period (about 8 quads per year). For the dispersed industrial heat, the HTR multiplex has a heat cost about half that of fluidized bed combustors (FBC) operating at a capacity factor of 0.3 and about equal to that of FBC's operating at a capacity factor of 0.9. For the peaking and mid-range electric market, the HTR multiplex can supply electric energy at costs three-fourths that of FBC's operating at a capacity of 0.1 and equal to that of FBC's operating at a capacity factor of 0.3.

For the ammonia and methanol markets, the HTR multiplex costs are about equal to coal and somewhat higher than methane with current fuel prices. Application to coal refining is similar to the ammonia and methanol markets. Current economic analyses show approximate equivalence for coal and nuclear heat. However, if coal refining is implemented on a large scale in the U.S., the economics would be expected to change rapidly in favor of the HTR because coal reserves would be depleted more rapidly and coal prices would increase relative to nuclear.

1. INTRODUCTION

1.1 BACKGROUND

The HTR Multiplex utilizes the HTR as a heat source to produce multiple forms of energy. A specific type of multiplex using the thermochemical pipe (TCP) was analyzed in the *HTR Multiplex Market Assessment* (Ref. 11). The major finding of that study was that a large potential U.S. market existed in two segments of the electric and industrial heat markets. It was concluded that the HTR Multiplex could provide peaking and mid-range electricity plus industrial heat for one- and two-shift operations at costs approximately 50 percent lower than available alternatives. The market size was estimated at 300 GW_t (about 7 quads per year) in the 1995 to 2010 time period.

1.2 STUDY OBJECTIVES AND SCOPE

The objectives of this study are to:

- Perform additional HTR market assessments
- Provide guidance, if possible, on preferred unit sizes and other desired characteristics of an HTR Multiplex.

Industrial process heat requirements and the associated HTR markets are described in Section 2 of this document and some estimates of Multiplex characteristics are provided in Section 3.

2. INDUSTRIAL PROCESS HEAT REQUIREMENTS

2.1 INTRODUCTION

The purpose of this preliminary market survey is to identify and estimate the characteristics of industrial applications for which the high temperature reactor (HTR) can serve as the source of necessary process heat. HTR application studies by Oak Ridge National Laboratory (Ref. 18) and several industrial contractors (Ref. 6 and 7) beginning about five years ago were unanimous in selecting processes involving steam reforming of natural gas and conversion of coal to clean gas and liquid fuels as two prime candidates. More recently, General Electric-TEMPO proposed the so-called HTR-Multiplex application (Ref. 11) based on using thermochemical pipeline (TCP) technology to satisfy the requirement for industrial process heat and peaking and mid-range electric generation.

In these selected applications, the HTR displaces the fossil fuel used in the conventional process. Current or anticipated practice in the U.S. is such that a different fuel or mix would be displaced, hence conserved, in each application area:

- natural gas in the reforming industries,
- coal in the coal conversion industries, and
- oil and natural gas used to raise process steam and in some cases for direct heating in industry in general.

The following sections comprise a market analysis of each application area, taking account of both domestic and worldwide trends as they affect supply and demand. Although technological matters are considered in greater detail elsewhere, those relevant to the penetration of HTR-assisted processes in competition with alternative processes are identified.

2.2 THE REFORMER INDUSTRIES

Ammonia and methanol are the primary products of the industries based on steam reforming of natural gas. The more than 16 million tons of ammonia produced in 1978 made it the third ranked industrial chemical, and the 3.2 million tons of methanol rank it in twentieth place (*Chemical and Engineering News*, June 12, 1978). More than 97 percent of ammonia production and the great bulk of methanol production is from natural gas reforming; a minor but significant amount of methanol is obtained from other processes. Some merchant hydrogen is produced by reforming, as are the commercially useful co-products, carbon monoxide and carbon dioxide.

Because of the essential similarity of the initial reforming steps in ammonia and methanol manufacture and because the methanol plant requires the carbon dioxide byproduct of the ammonia plant, it is common practice to integrate the two. This is also evidenced by the fact that during the past decade, annual production of methanol has consistently run 18 to 21 percent of ammonia production.

Projected domestic and worldwide demand, the appearance of new sources of supply, and the development of competing technologies are the major factors which determine the potential penetration of HTR-assisted reforming. Demand and supply issues pertaining to ammonia and methanol are discussed here.

2.2.1 Ammonia

Consumption of ammonia is keyed to its role in agriculture; about 75 percent of U.S. production goes to fertilizer uses, as shown by its overall use pattern (Ref. 12).

	Percent
Fertilizers and animal feeds	75
Fiber and plastic intermediates	9
Explosives	5
Paper and rubber products	2
Other (refrigerants, cleaners, losses, etc.)	9
	<hr/> 100

2.2.1.1 Demand

Total domestic demand for ammonia is presently about 17 million tons per year. The recent production statistics and derived projections are shown in Figure 2-1. The data indicate an annual growth rate of 11.6 percent from 1950 to 1966, followed by a marked decrease to 3.3 percent per year between 1967 and 1978. Using the standard error of estimate in this latter period to characterize the uncertainty in projecting continued demand growth at the 3.3 percent rate results in the range shown by the shaded area. The upper limit of the uncertainty range represents annual growth at 5.1 percent; the lower limit, at 1.5 percent. The most likely projected demand for the year 2000 is 36 million tons; values for the rapid and slow growth extremes are 53 and 24 million tons, respectively.

Because of its predominantly agricultural use, ammonia demand growth can be keyed to projected growth in farm production for which typical estimates are 3 to 4 percent per year. While this exceeds projected U.S. population growth, saturation of ammonia demand is avoided by several factors. Increased utilization of fertilizer has enabled reduction of other agricultural inputs (cropland, labor, machinery, etc.) while increasing yield. High-yield plant strains and heavy fertilization have been most responsible for growth in productivity, and ultimate yields obtainable by further increases in fertilizer use appear not to have been reached in even the most advanced intensive farming areas (Ref. 13). In addition, U.S. food exports continue to be crucial in maintaining an acceptable balance of trade.

Worldwide it is reported (*Oil and Gas Journal*, January 1, 1979) that ammonia production capacity presently exceeds demand, but this is only true in the sense that the ability to purchase, distribute, and use the product has not grown as rapidly in recent years as has the number of packaged ammonia plants erected near natural gas sources that have no other markets. On a per capita basis, ammonia consumption

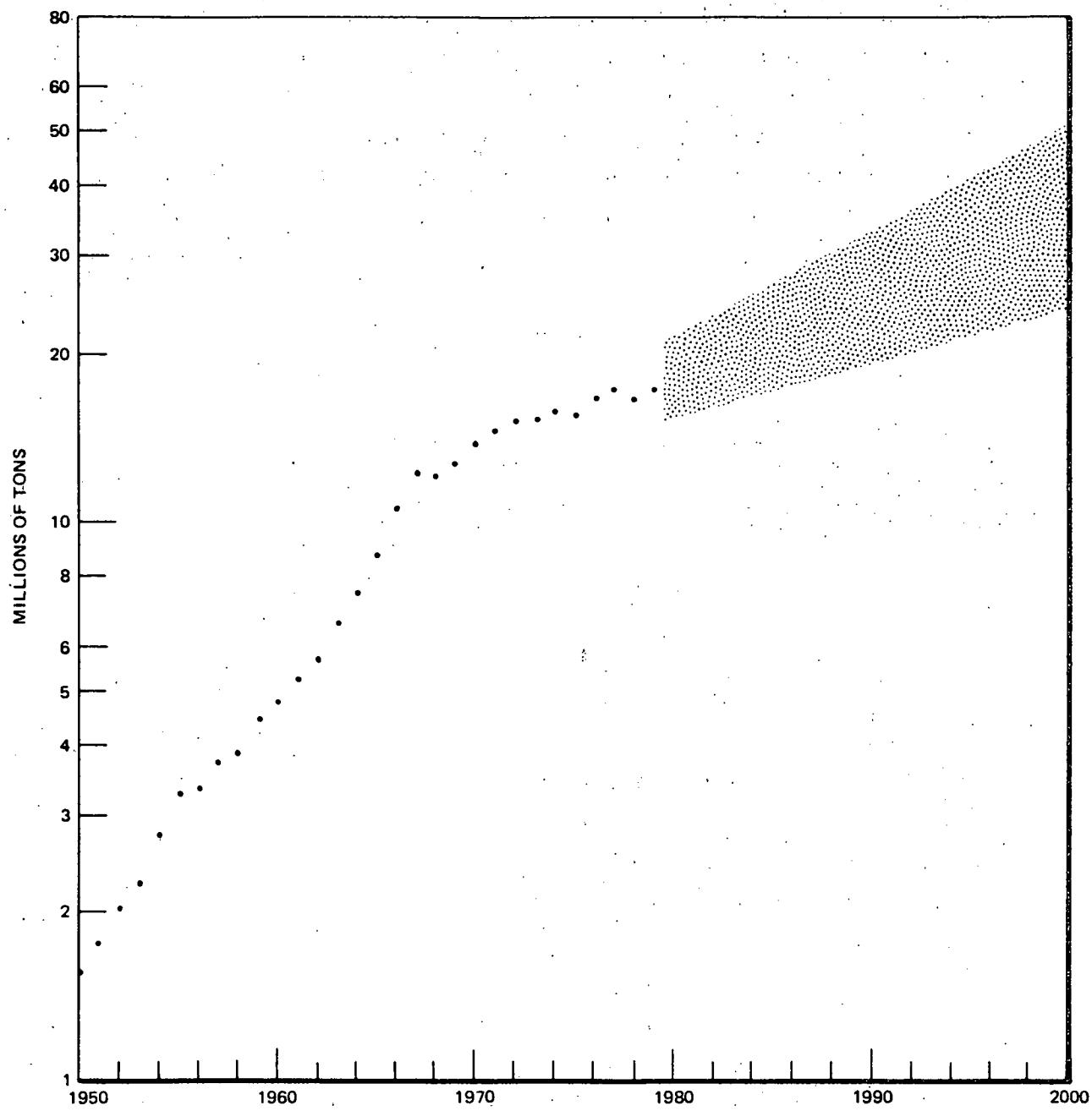


Figure 2-1. Ammonia production, 1950-1978, and projected domestic demand

in 1972 amounted to 97 pounds in the U.S., 61 pounds in Europe, and less than 12 pounds throughout the rest of the world (Ref. 17). Average per capita consumption throughout the world was 22 pounds. Were this to be increased to the European level for the 4.4 billion world population projected for 1980, a production rate of 134 million tons per year would be required, a doubling of the present annual capacity of about 75 million tons assuming 90 percent utilization. The World Bank estimates that additional global capacity of about 63 million tons per year of ammonia will be required between 1980 and 1990 (*Oil and Gas Journal*, January 1, 1979).

In short, it is apparent that the potential demand for ammonia, especially on a world basis, exceeds the supply and will continue to grow for the foreseeable future.

2.2.1.2 Supply

As recently as five years ago, domestic supplies of ammonia were tight due to feedstock limitations, and world supplies were tight due to inadequate capacity. Prices were above \$400 per ton in 1975. This led to rapid domestic and foreign capacity increases. Together with a greater availability of natural gas and the weather-dependent demand fluctuations characteristic of the agricultural industry, the capacity expansion resulted in excess supply and depressed prices. Ammonia sold for less than \$100 per ton in 1978 and recent estimates are that 20 to 35 percent of U.S. capacity might be shut down.

More important than these short-term imbalances is the fact that since 1974 the U.S. has gone from a net exporter to a net importer of nitrogenous fertilizers. This has resulted from the industrialization of countries with surplus natural gas using ammonia production as a way of marketing gas that would otherwise be shut in or flared. Imported ammonia was available on the U.S. Gulf Coast in 1978 at \$75-85 per ton (*Oil and Gas Journal*, January 1, 1979). The increasing volume of imports is coming from the USSR, Canada, Mexico, Trinidad, and Tobago. Between now and 1983, the Department of Commerce estimates that real growth in domestic demand will average 3 percent per year (which will still leave unused capacity), but that prices will rise because with the USSR emerging as the leading exporter of ammonia it is difficult to conclude that the Soviets will want to keep prices down (Ref. 3). There is additional potential for ammonia production in other gas-rich countries such as Venezuela, Nigeria, and countries of the Persian Gulf area, and the current excess capacity is still growing.

The techno-economic factors affecting ammonia supply are then: that the highly developed steam reforming process by which it is manufactured from natural gas is preferred to all other processes; that the relatively small investment cost, modularity, and self-contained nature of these plants permits their installation near the gas source; and that the product is easily and cheaply shipped in bulk to wherever markets exist. Therefore, it becomes necessary to consider world trade patterns in assessing future U.S. sources of supply. Viewed this way, imported ammonia is seen as a safer and effectively cheaper augmentation of domestic natural gas supplies than is LNG, and one which has the same adverse implications regarding U.S. dependence on foreign resources.

2.2.1.3 Alternative Technologies

Historically, ammonia has been obtained in a variety of ways: as a byproduct in coke production, from byproduct hydrogen (petroleum refinery, chloralkali plant) with nitrogen by air separation, etc. None of these has the potential to compete with newer processes.

At present, steam reforming of natural gas accounts for about 95 percent of U.S. capacity and 75-80 percent of world capacity (*Chemical and Engineering News*, August 14, 1978). The next most common process, widespread in Europe and Japan where the feedstock must be imported, is steam reforming of light hydrocarbons, primarily the naphtha fraction. Operation of a naphtha fed and fired reformer furnace differs little from its natural gas counterpart (Ref. 1).

Syngas for ammonia production is also prepared by partial oxidation of a variety of heavy petroleum fractions or coals, and by most coal gasification processes. More than 50 modern, coal-based ammonia plants employing the Koppers-Totzek gasifier are in operation around the world (Ref. 9). The production of ammonia from coal is considered the prime competing technology to natural gas reforming in the U.S. Although coal-based plants are both more expensive and energetically less efficient, they become competitive when natural gas is four times as expensive as coal per unit energy, e.g., gas at \$4/Mscf (\$4/MMBtu) and coal is \$25/ton (\$1/MMBtu) both lead to an ammonia production cost of \$180/ton with the coal-based plant investment estimated to be twice that of the gas-based plant. In the coal-based process, the gasification is assisted by the oxygen from an air separation unit, and the nitrogen is added to the hydrogen isolated from the syngas to provide the reactants for the ammonia synthesis. It has been argued that expanding the natural gas supply by converting ammonia manufacture to a coal basis is more economical than by building SNG plants (Ref. 9).

2.2.2 Methanol

The present interest in methanol (methyl alcohol) arises from its potential role as a fuel for the transportation sector and for electric utility combustion turbines. These applications imply an annual production rate far greater than the current 3 to 3.5 million ton level, more than 75 percent of which is consumed in the chemical industry as shown by the following use pattern (Ref. 12):

	Percent
Formaldehyde (for phenolic resins and plastics)	45
Dimethyl terephthalate (for polyester films and fibers, Dacron, Mylar)	10
Methyl methacrylate (for acrylic resins and plastics)	8
Methyl esters, amines, and halides (for fumigants, adhesives, disinfectants, solvents, etc.)	8
Acetic acid (for acetates)	4

	Percent
Solvents	10
Miscellaneous (denaturant, antifreeze, antiknock agent, etc.; exports)	15
	<u>100</u>

2.2.2.1 Demand

It is emphasized that recent statistical market data reflect methanol's role as a chemical intermediate primarily for resins and plastics; methanol as a fuel is an entirely separate matter. The demand data are shown in Figure 2-2. From 1954 to 1974, demand grew at 9.5 percent per year, but since 1974 it has varied erratically between 2.5 and 3.5 million tons per year. The data are too few to determine whether a new trend has appeared or whether the former growth rate will reassert itself after a one-time (1974/75) decrease in demand, but both interpretations are feasible.

Projections of methanol demand as a chemical intermediate are of no consequence to its potential demand as a fuel. No effort, therefore, has been made to extrapolate the data of Figure 2-2. Were adequate supplies available at competitive prices, methanol would find a market today as a gasoline extender and as a combustion turbine fuel. Only minor modifications of existing prime movers are needed to use this fuel efficiently.

Within the next 10-20 years in the synthetic fuel context, the demand for methanol could exceed that for oil if there were some way to satisfy it. Specific projections call for levels of 25 million tons/year in 1980, 50 million in 1990, and 400 million by the turn of the century (*Chemical and Engineering News*, August 25, 1975; *Technology Review*, December 1975). Since production at these levels is envisioned as part of the synthetic fuels from coal program, further consideration is deferred to a later section of this report. In any event, it is unlikely that large increases in the demand for methanol would be met by increasing the amount produced by natural gas reforming.

2.2.2.2 Supply

Most methanol is produced by steam reforming of natural gas. The reformer furnace is much like those used in ammonia manufacture, the main difference being that carbon dioxide is charged to the furnace along with the natural gas and steam. Since carbon dioxide is a byproduct of ammonia production, the two types of plants are frequently combined. Some methanol is obtained from the reforming or partial oxidation of light hydrocarbon (propane, butane) offstreams in refineries and from natural gas liquids in gas processing. A small amount comes from charcoal manufacture by pyrolysis of wood.

Almost identical weights of methanol and ammonia are obtained from the same quantity of natural gas, and the character and cost of the processing plants are so alike that production costs are practically the same; the 1978 methanol price of 46 cents per gallon is equivalent to \$140 per ton, and ammonia is estimated at \$120 per ton. Methanol is even easier to transport than ammonia. The consequence of these

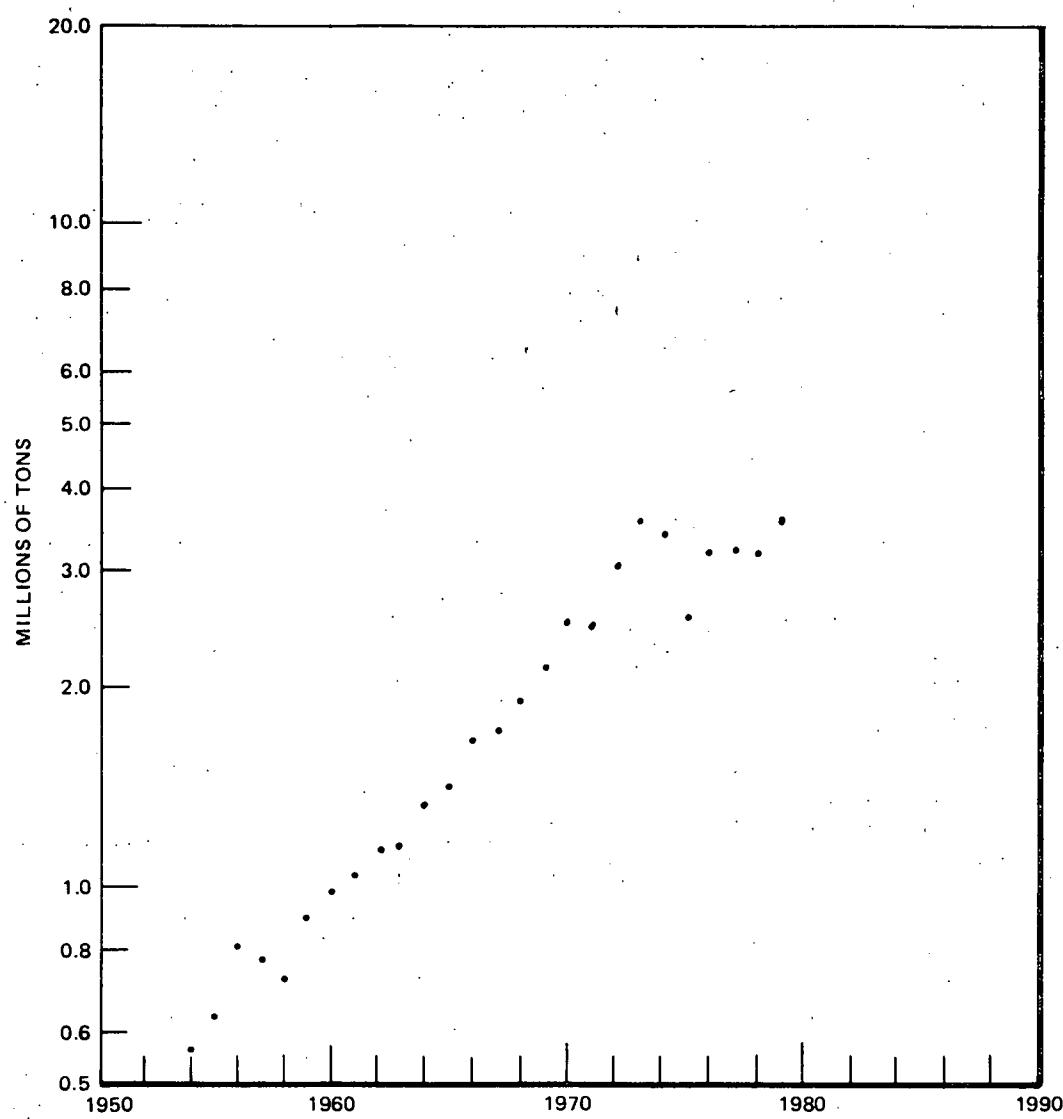


Figure 2-2. Methanol Production, 1954-1978

facts is that the methanol supply picture is virtually the same as that for ammonia, with the implication that imported methanol can be available in great quantities at prices below those for the domestic product. Celanese and Texas Eastern are presently involved in a Saudi project for a 715,000 ton per year methanol plant (more than a fifth of U.S. production), and another plant of the same size is to be constructed by a Japanese consortium, presumably for Japanese consumption (*Chemical and Engineering News*, March 6, 1978). As with ammonia, world trade in methanol is an important factor in the energy market which to some extent will determine the economic feasibility of alternative modes of production.

2.2.2.3 Alternative Technologies

The promise of methanol as a fuel is based on its production from coal. Possibly the earliest test of the feasibility of this venture on a commercial scale will be two 8.5 million ton per year plants currently being designed; they would increase U.S. capacity by more than five times. One is to be located on the Alaskan coast near Anchorage and its methanol will be shipped by tanker to electric utility plants near San Francisco and Los Angeles starting in 1983; the other will convert North Dakota lignite to methanol for midwestern utilities beginning in 1984. The economic premise for these designs is a methanol price of about 30 cents a gallon (91 dollars per ton) based on coal at 25 dollars per ton (*Chemical and Engineering News*, April 2, 1979). A recent cost validation study by the Army Engineer Division, Huntsville confirms the investment and operating costs for a 21 million ton per year methanol plant at levels which support a price of 30-32 cents a gallon in the first years of operation (Ref. 19). To achieve this low a production cost via natural gas reforming would require a gas price of \$1.50 per million Btu (non-levelized).

2.2.3 Hydrogen

Merchant hydrogen, hydrogen manufactured for shipment as such in liquid or gaseous form, is a small volume product compared with ammonia and methanol. Its production statistics are difficult to interpret because, as a byproduct of many processes and as a useful reactant or fuel for related processes, its production as such may not be reported. Further, the basis for the official figures has been changed at least twice to exclude hydrogen produced as an ammonia or methanol intermediate, that used as a fuel, and that produced by petroleum refineries. What little information remains in the production statistics shows tremendous fluctuations in specific years resulting from the demand for liquid hydrogen fuel in the space program.

To obtain some idea of whether merchant hydrogen production represents an important application area for the HTR, its maximum size relative to that of the ammonia plus methanol market can be estimated by adopting government production figures (much larger than shipments) and by assuming that all that hydrogen is from steam reforming. Then the almost 90 billion cubic foot production level of 1977 would have required less than 4 percent of the natural gas used to manufacture ammonia and methanol in that year. Stated otherwise, hydrogen by itself does not represent a significant application area as compared with the other two products.

Because of the cost of shipping hydrogen as a high pressure gas or cryogenic liquid, it would not seem to share the vulnerability of the other products to low cost imports. This may be deceptive, however, since hydrogen is presently only obtained for certain small-scale industrial uses by catalytic decomposition of methanol or ammonia. The economics at the final point of use determines which method of production might be the preferred one for a particular application.

Whatever the appropriate figure for merchant hydrogen production, demand by user industries, excluding the space shuttle program, is expected to grow at about 10 percent per year (*Chemical and Engineering News*, May 15, 1978). Hydrogen finds a diversity of uses in the chemical processing, metallurgical, food processing, pharmaceutical, electrical equipment, and electronics industries.

Most merchant hydrogen, especially that shipped as liquid, is manufactured by steam reforming of natural gas. Other commercial sources are from petroleum refineries and chloralkali plants. To the extent that these sources of supply might be unable to meet demand, a number of other processes are available. Some have been used extensively in the past (hydrogen from water gas, producer gas, and by the steam-iron reaction), others have been and are being developed to exploit less expensive feedstocks (partial oxidation of heavy hydrocarbons, coal gasification).

2.2.4 HTR Market Assessment — Ammonia, Methanol, and Hydrogen

The previous section described the current and projected market situation for ammonia, methanol, and hydrogen by steam reforming of natural gas. Its general conclusions are that growth of demand for these products can be confidently predicted, but that the increased supply will be provided by imports and coal-based technologies (discussed later). Decreasing rates of production and consequent high prices of domestic natural gas will not permit its use to satisfy these demands, especially that for methanol as a fuel.

Developmental improvements in both the reformer furnace and the downstream processes for both ammonia and methanol have continuously reduced the amount of natural gas required per ton of product; recent data indicate that, coincidentally, 26 million Btu per ton is the appropriate figure (*Hydrocarbon Processing*, November 1977; *Processing (UK)*, July 1978; *Oil and Gas Journal*, December 4, 1978). Of this, the fraction of natural gas burned as fuel is a little higher for ammonia (38 percent) than for methanol (28 percent, assuming carbon dioxide feed available). Approximately, then, the HTR-heated system concept displaces the fuel fraction of about one-third the natural gas needed. If HTR heat cost only two-thirds as much as natural gas, its effect would be to reduce the product price by 11 percent while conserving one-third the gas that would otherwise be used. This is probably too small an economic margin on which to base a market penetration forecast given the much larger impacts of other supply options.

We conclude that the ability of the HTR to displace natural gas burned as fuel in the reformer industries is not a significant part of the rationale for its need.

2.3 THE COAL CONVERSION INDUSTRIES

2.3.1 Background

It is expected that U.S. production of coal will increase markedly in the near future in response to the need for additional fuel supplies. Most of this coal will be burned directly in electric utility and industrial boilers with appropriate pollution controls. For coal to increase its contribution to other sectors (fuel supply for automotive transportation, residential and commercial heating, utility generation of peaking electric power, and industrial processes with special requirements), it must be converted to clean burning, liquid or gaseous fuels. A large industry manufacturing synthetic fuels from coal is expected to develop by the end of the century.

The liquid fuels envisioned from coal are syncrude, which can be processed much like crude petroleum, and methanol; the gaseous fuel is SNG (substitute natural gas) to supplement natural gas production. Manufacturing processes for these fuels use coal as both feedstock and fuel. It has been suggested that HTR-generated heat can effectively displace the coal used as fuel. The net effect would be to increase the coal-based yield of desired products, thereby conserving coal and reducing the environmental impact of coal mining and processing. This section assesses the potential market for the HTR in this role.

2.3.2 Market Factors — Demand and Supply

The U.S. demand for quality fuels has been growing while the supply based on domestic production has decreased; imports have filled the gap, but the economic consequences are severe. To compensate for declining domestic production of gas and oil, to provide for the increasing demand, and to control the dependence on imports, increasing reliance is being placed on coal. With 31 percent of the world's known coal resources, the U.S. is estimated to have over 250 billion tons of coal recoverable under present economic conditions with current technology (Ref. 8). During the past decade, production has increased from about 550 to almost 700 million tons per year; this figure is expected to double in the next 10 years. Some recent production forecasts are shown in Table 2-1.

Perspective on utilization of the coal resource is provided by the Department of Energy's medium level consumption forecast, Table 2-2. The overall growth rate of 6.5 percent per year encompasses rapid penetration by coal into the industrial sector, presumably displacing oil and gas, and phenomenal growth of the synthetic fuels industry.

2.3.3 Process Factors

Many conversion processes for coal liquefaction and gasification are under development; some gasification units have been in commercial use elsewhere in the world for years. The cost and operating characteristics of these processes show as much variability as do the physical properties of the coals they are designed to convert. Typical factors for representative processes are given below.

Table 2-1
UNITED STATES COAL PRODUCTION FORECASTS
(millions of short tons per year)

Source	Date of Forecast	1985	1990	2000
Project Independence	1974	1100	1300	
Project Interdependence	1977	940	1225	
National Energy Plan	1977	1050	1250	
Department of Commerce	1977	890		1860
National Research Council	1977	995	1250	1700
Department of Energy	1978	1112	1520	

Sources: Ref. 8; *Oil and Gas Journal*, March 26, 1979.

Table 2-2
UNITED STATES MARKET FORECAST FOR COAL:
MEDIUM CONSUMPTION SCENARIO
(millions of short tons per year)

	1977	1985	1990	Average Growth Rate (% per year)
Electric Utility	475	760	1007	6.0
Industrial	60	159	279	12.6
Metallurgical	77	96	100	2.0
Synthetic Fuel	—	22	56	20.0 ^(b)
Other ^(a)	61	75	78	2.0
TOTAL	673	1112	1520	6.5

^(a)Includes residential and commercial use and exports.

^(b)Over 1985-1990 period.

Source: U.S. Department of Energy

2.3.3.1 Coal Liquefaction

Coal can be dissolved in a hydrocarbon solvent at moderately elevated temperatures. With hydrogen present under pressure and, in some processes, with a catalyst, dissolution of the coal proceeds rapidly and almost completely. The syncrude product is refined much like crude petroleum, but yields a larger fraction of heavier oils at the expense of light aliphatic compounds (e.g., gasoline components). Operating conditions and yields of six liquefaction processes are shown in Table 2-3; yields are of refined products in barrels per ton of coal and hydrogen consumed is in thousands of standard cubic feet per ton of coal. In every case, the hydrogen required is prepared in an ancillary unit employing steam-oxygen gasification of undissolved residue or steam reforming of light hydrocarbons flashed from the reactor effluent. For some combinations of process and coal, extra coal would be gasified to satisfy the hydrogen requirement.

2.3.3.2 Coal Gasification

Gasification is the first step in converting coal to pipeline quality gas or to methanol; different gasifier conditions are employed to produce the proper syngas composition for the necessary downstream processing. In general, SNG production is favored by lower temperature gasification. This is followed by shift conversion to obtain a 3:1 ratio of hydrogen to carbon monoxide for the methanation step. Methanol production calls for higher temperature gasification which produces a syngas very low in methane. The shift converter is operated to produce a 2:1 hydrogen-carbon monoxide mixture for the low pressure, catalytic methanol process. Because of the ease with which methanol can be separated from SNG, efficient co-product plants can be designed based on the sequence: shift conversion, methanol synthesis and removal, shift conversion, methanation to SNG (Ref. 14).

Table 2-3
CHARACTERISTICS OF COAL LIQUEFACTION PROCESSES

	H-Coal	SRC	Synthoil	CCL (sub-bitum.)	CCL (bitum.)	CSF
Yield (bbl/t)	2.3	3.7 ^(a)	3.0	3.2	4.0	2.0
Reactor Temp. (°F)	850	850	840	800	800	730
Reactor Pressure (psi)	3000	1500	4000	3000	3000	400
Hydrogen Used (Mscf/t)	15.3	7.6	9.0	22.8	17.5	16.3
Dissolution Catalyst	Yes	No	Yes	Yes	Yes	No ^(b)

^(a)Liquid product above 300 °F; solid clean fuel (yield 1116 lb/t) at ambient temperature.

^(b)Dissolution conducted without hydrogen; reactor effluent is hydrogenated.

Source: Ref. 4

Typical gasifier conditions for methanol are 2400°F and 1000 psi, yielding 0.78 tons or 5.6 barrels of methanol per ton of coal. Since methanol has only 43 percent of the low heating value of oil on a volumetric basis, this is equivalent to 2.4 barrels of oil equivalent per ton of coal, a value comparable to that of the direct coal liquefaction processes (Table 2-3).

Yields and operating conditions for several SNG processes are shown in Table 2-4. An important difference among the processes is how the large amount of heat required for the steam-carbon reaction is provided to the gasifier. In every case, the source of heat is combustion of the unreacted char left after gasification. In some processes, this is effected by providing oxygen to the gasifier; in others, by burning the char outside the gasifier and coupling heat to the gasifier by a high temperature heat transfer medium.

2.3.4 HTR Applications

There are two basically different ways of using heat from the HTR to assist in coal conversion. One provides the heat of reaction for steam reforming to generate hydrogen needed in the process. This applies to the direct liquefaction processes and to high pressure gasification systems in which the exothermic reaction between carbon and hydrogen producing methane is important. (In these processes, e.g., Synthane and Hydrane, an effort is made to achieve significant methane formation in the gasifier, rather than relying completely on downstream methanation. The advantage is that the heat generated assists in the endothermic steam gasification reaction.) Since hydrogen rather than high-temperature heat is desired, the interface between the HTR-heated reformer and the coal conversion process is simply a hydrogen delivery pipe. Using either some of the SNG product or a light hydrocarbon cut (naphtha) from the liquid product, the technology is identical to that considered in the natural gas reforming case.

The other mode of coupling the HTR to the coal process is by heat transfer at high temperatures. This applies primarily to the gasification systems, and could be achieved either by incorporating a heat exchanger in the gasifier or by preheating the unreacted gas after SNG separation plus additional steam being charged to the gasifier (Ref. 16). This concept poses more severe technical and materials problems than does the reformer approach.

Table 2-4
CHARACTERISTICS OF COAL TO SNG PROCESSES

	Kellogg	Bi-Gas	CSG	Synthane	Hygas	FGA
Yield (Mscf/t)	18.9	17.7	9.0	14.5	15.4	15.3
Product LHV (Btu/scf)	914	957	955	928	950	960
Gasifier Temperature (°F)	1830	2500	1520	1800	1850	1800
Gasifier Pressure (psi)	420	1115	150	615	1115	1115

Source: Ref. 6.

Whichever concept is employed, the net effect is to replace heat from combustion of coal or some coal product (char, SNG) with heat from the HTR. This increases the yield of the desired product per unit of coal charged, thus conserving coal and eliminating combustion pollutants at the expense of the nuclear fuel cycle. The amount of coal displaced depends strongly on the conversion process design, the mode of employing the HTR, and especially on the heating value of the coal (which varies by a factor of two from lignites to bituminous coals). Given these uncertainties, the range of estimated displacement is relatively large, from 12 percent (H-Coal liquefaction based on prime product only; Ref. 10) to 40 percent (SNG production from lignite; Ref. 16).

2.3.5 Market Assessment — Coal Conversion

Since the confidence level that can be assigned to any particular synthetic fuel scenario is small, the estimates of this section must be taken simply as consequences of the assumptions made rather than objective estimates of a predictable trend. It is only in that sense that the information of the preceding sections is used.

If commercial HTRs were available in the time frame and a coal displacement factor of 25 percent is assumed, then the 56 million ton per year rate of coal consumption for synfuels in 1990 (Table 2-2) would create a market for 13 GW, from HTRs and would result in a third more product than if the processes were self-fueled. Beyond that date, the energy demand for coal conversion can be expected to grow at the same rate as the synfuels industry; slower than the 20 percent per year of Table 2-2, but at a significant rate.

If at some time in the early part of the 21st century, HTR-assisted synfuel production were to equal the three billion barrel per year rate of oil importation established in 1978, almost 200 GW, of reactor heat (65 large HTRs) and three-quarters of a billion tons of coal a year would be needed.

From such scenarios, a large potential market for HTRs in synfuel production might be inferred. Other factors, however, that must be considered include cost, technological, and policy issues.

As regards cost, three facts are apparent: coal conversion plants are expensive, so fixed charges comprise a large component of product price; only a fraction of the coal requirement can be displaced; and it is unlikely that HTR-generated heat will be cheaper than coal-generated heat, especially at a large coal processing plant. Compounding the cost issue and making the conclusions dependent on specific application designs is the fact that the fuels used in some fossil-fueled processes are byproducts of the process itself such as coke, coker gas, filter cake, etc. These fuels, containing much of the ash and sulfur of the coal, may in fact be the materials that would be displaced by the HTR, and if a market for them exists, they would have to be transported to it to realize their economic benefit.

A series of conceptual plant cost analyses comparing fossil- and HTR-fueled processes reach the general conclusion that the production costs under the two alternatives are virtually the same, and that whatever differences there are are very much smaller than the uncertainties in the estimates (Ref. 21). Thus, there is no evidence and no reason to believe that HTR-assisted coal conversion would be

significantly cheaper than the conventional approach under foreseeable circumstances of high levels of coal use in the United States. Whether the HTR version would even be cost competitive with the conventional plant would require a detailed engineering and cost evaluation with specific locations, markets, and prices identified.

The technological issues address two problem areas: specific developments such as the means for coupling HTR heat to coal gasifiers, and general issues such as the compounding of technical difficulties resulting from combining two new technologies in early stages of their development.

Finally, and perhaps most important, is the policy issue of developing a rationale for one new energy technology, the HTR, on the needs of another, where the prime rationale for the other one is the abundance of the resource it is designed to exploit. While this question may not be stated explicitly, it is bound to be one of the issues underlying consideration of HTR applications to coal conversion.

A related aspect is the question of whether the energy generated by the nuclear technology might not be put to a still better end use, for example, by displacing the coal-generated clean fuel itself. While this may not be appropriate to the use of coal liquids as transportable vehicular fuels, it is certainly appropriate to many of the uses of natural oil and gas in the industrial, commercial, and residential sectors which coal derived products are expected to serve. Just such an application is the subject of the next section of this market survey.

In the light of these issues, it is believed that despite its potential size, the coal conversion industries do not represent the kind of market opportunity for the HTR which would elicit firm support for its development.

2.4 THE DISTRIBUTED HEAT MARKET

The third area in which a significant demand for the HTR can be recognized is the geographically and functionally distributed market for industrial process heat and generation of mid-range and peak load electricity. In this role, were it available today, the HTR would displace primarily oil and gas, clean fuels burned by industry and the electric utilities in urban-industrial areas. Over the next 20 years, the extent to which environmentally acceptable ways of distributing and burning coal will enable it to penetrate this market, or the economics of clean, coal-derived fuels as an alternative, will determine the fuel mix which the HTR would displace toward the end of the century. It seems certain, however, that the ability to satisfy this energy demand under foreseeable environmental and economic constraints will be critical if industrial growth is to continue.

2.4.1 The Multiplex Concept

The technology which enables the HTR to compete effectively in serving the distributed industrial and utility market is the thermochemical pipeline (TCP) concept: use of the methane reforming equilibrium to convert thermal energy to chemical form as a mixture of stable gases. In this concept as presently envisioned, the thermal energy is regenerated at industrial or utility facilities where size and load

pattern make for favorable economics. In typical industrial applications, process heat and steam needs will be controlling, with possible cogeneration of electricity. In utility facilities, intermediate and peak power loads will control, with the potential for cogeneration of steam or hot water for district heating.

Using the various cogeneration options and exploiting the intrinsic storage capacity of the TCP system leads to favorable economics in numerous applications. This is the basis of the HTR-Multiplex concept (Ref. 11). The technology and system costs of the TCP have been described in detail by Vakil and Flock (Ref. 20). Both studies recognize that process heat demands constitute a significant part of the HTR market and offer estimates of its size and characteristics based on current industrial fuel use statistics. Leeth and Meyer emphasize geographic distribution and projected growth; Vakil and Flock, the size distribution and load patterns of the various industries.

Using 1974 data, the latter study finds that the annual industrial heat demand which can be served technically (i.e., at temperatures below 1100 °F) is about 8.5 quads (quadrillion Btu), of which 6.5 quads is estimated to be economically viable based on installation size and 2.5 quads based on both size and use pattern. This last figure is equivalent to about 80 GW. Projecting this baseline value at a net industrial energy growth rate of one percent per year to the end of the century, and assuming replacement of the existing industrial heating capacity over the same period based on an average 30-year life, implies over 100 GW of new capacity by year 2000. This is a sufficiently attractive market to justify development of HTR-TCP technology.

2.4.2 Market Assessment

Because the basic data regarding industrial energy consumption describes fuel and electricity purchases by industry rather than energy end use, ancillary analyses of each industry and numerous assumptions are needed to define the HTR-TCP applications. For this reason, estimates based on independent approaches are justified. The present work offers an estimate based on industrial process steam demand, i.e., use of the HTR-TCP to displace fuels used under industrial boilers. There is no doubt that this is a technically feasible application, and since the system configuration has not been developed in detail (e.g., small industrial catalytic boilers versus utility-sized methanators with steam distribution), economic competitiveness is yet undetermined.

2.4.2.1 Demand

Of the four major sectors of the U.S. economy, the industrial sector is the largest energy consumer, accounting for 36 percent of gross national energy use in 1977 and for the largest share of coal, natural gas, and electricity use. Only the transportation sector's consumption of oil exceeded the industrial sector's consumption of all other fuels.

Within the industrial sector, the manufacturing division (SIC codes 20-39) accounts for about 65 percent of the energy demand; the non-manufacturing industries (agriculture, forestry, livestock, fisheries,

mining, natural gas and petroleum production, construction, transportation for hire, communication and utility services, and wholesale and retail trade) consume only about half as much.

Energy consumption by fuel and by industry group is shown in Table 2-5 for the manufacturing division in 1976. The values, in trillions of Btu's are shown individually for the six largest energy consuming groups and combined for the remaining 14. The chemical and primary metal group account for 44 percent of the total; the top six groups account for over 78 percent. Electricity is expressed as gross fuel value assuming a generating efficiency of one-third (heat rate of 10,240 Btu/kWh). Distillate and residual fuels are combined as oil; coal, coke, and breeze as coal. "Other" fuels are, in many cases, byproducts of the particular industries.

Estimates of the fraction of fuel used under boilers for raising process steam have been assembled by Fejer and Larson (1974) and are shown in Table 2-6. Only purchased oil, coal, and gas used for process steam are considered displaceable by the HTR-TCP system; use of "other" fuels is assumed to be unchanged and electricity is assumed to be needed for motive power, electrolysis, etc. The total demand is seen to exceed 4.0 quads for 1976. The last column of the table shows the percentage of the total energy demand of each industry group which is needed to raise process steam; the wide variation among industries is noted.

Table 2-5
ENERGY CONSUMPTION BY INDUSTRY GROUP AND FUEL, 1976 (10¹² Btu)

Code	Industry Group	Oil	Coal	Gas	Other	Electricity	Total
28	Chemicals	341	337	1710	126	1642	4156
33	Primary Metals	314	520	959	83	1652	3527
26	Paper	507	221	366	49	706	1850
29	Petroleum Products	96	6	1068	21	330	1521
32	Stone, Clay, Glass	143	301	601	63	305	1412
20	Food	176	88	448	80	426	1219
—	All Other	412	162	893	203	2090	3759
	TOTAL	1990	1634	6045	626	7150	17444

(Values may not add due to rounding.)

Source: Calculated from Department of Commerce, 1978 (Ref. 2).

Table 2-6
FUEL USED FOR PROCESS STEAM IN MANUFACTURING INDUSTRIES

Code	Industry Group	Percent by Fuel:			Consumption 1976 (10¹² Btu)	Percent of Total Energy
		Oil	Coal	Gas		
28	Chemicals	40	75	30	902	22
33	Primary Metals	10	10	10	179	5
26	Paper	95	100	93	1044	56
29	Petroleum Products	40	90	30	364	24
32	Stone, Clay, Glass	10	10	10	104	7
20	Food	100	100	90	668	55
—	All Other	65-90	90-100	20-85	<u>776</u>	<u>13-35</u>
					4037 (total)	23 (average)

Source: Calculated from Ref. 5 and Table 2-5.

Projecting the process steam demand to the end of the century at a one percent annual growth rate leads to a 170 GW_c capacity for this application, practically all of which is still to be put in place as replacement or new capacity. This number is so large relative to even the most rapid early growth estimates for a new technology that its growth can hardly be marked limited.

2.4.2.3 Supply

In the 21st century time frame during which HTR-TCP technology can have a significant impact, natural petroleum and gas are likely to be in short supply worldwide. Coal, nuclear fission and possibly fusion, and solar technologies will be depended upon to energize society; principles of energy conservation and efficient utilization will be basic to engineering design. Flexibility in operation, cogeneration of heat and electricity, energy storage, and reliable distribution will characterize fixed systems. If present trends continue, not only the release but even the production of environmental pollutants will be more completely controlled.

Based on the information now available, the HTR-TCP system appears to compare very favorably with other modes of energy supply in the future context. Because much of the technology is novel, reliable costs estimates will be difficult to obtain until more development work is completed. Since this is also true

of the competing technologies, increased uncertainty in comparing alternatives is likely to characterize energy analysis for some time into the future.

Since a healthy industrial economy growing at a rate commensurate with population growth is necessary to maintain the standard of living, energy supply to industry will have to be ensured. The HTR-Multiplex concept appears to be a promising way of achieving that goal.

3. MULTIPLEX CHARACTERISTICS

3.1 ENERGY FORMS

The Multiplex can produce a variety of energy forms such as electricity, thermochemical pipe energy, synthetic fuels, and hot water. As noted in the previous HTR market assessments, production of electricity and thermochemical pipe (TCP) energy appears to offer major economic advantages in the near term. It is of interest therefore to determine whether an economic optimum exists as a function of the ratio of electricity-to-TCP energy.

Table 3-1 summarizes the Multiplex cases examined. These range from Case 1 (all electricity) to Case 6 (all TCP energy).

Input cost data for the Multiplex cost analyses is summarized in Table 3-2. The significant differences between these cost data and those used in Reference 11 are size-cost variations for the various turbine-generator plants and the fluidized bed combustor (FBC) systems. Note that the nuclear plant cost is based

Table 3-1
PBR "SPLIT" ESTIMATES (MW)*

	Item	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6
	Reactor Power	3000	3000	3000	3000	3000	3000
	Gross Heat	0	500	1000	1500	2000	2600
($\eta = 0.95$)	Net Heat	0	475	950	1425	1900	2470
($\eta = 0.40$)	Gross Electric	1200	1000	800	600	400	160
Plant Losses	Reactor Loop	40	40	40	40	40	40
	Reformer Loop	0	5	10	15	20	25
	Parasitic	10	17	23	30	37	45
Transmission Losses	Pipeline Loop	0	10	20	30	40	50
	Transmission	30	25	20	15	10	0
	Net Electric	1120	903	687	470	253	0
	η	0.373	0.459	0.546	0.632	0.718	0.823

*Based on data from Ref. 20.

Table 3-2
COST DATA

Item	Cost (1985 \$)
Nuclear Plant	\$310/kW _t
Steam Generator	\$ 60/kW _t
Steam Reformer Plant	\$105/kW _t
Methanator Plant	\$ 45/kW _t
Storage	\$ 70/kW _t -day
TC Pipeline	\$105/kW _t -100 miles
Turbine-Generator Plant (Base):	
1200 MW _e	\$400/kW _e
800 MW _e	\$410/kW _e
600 MW _e	\$435/kW _e
400 MW _e	\$465/kW _e
200 MW _e	\$510/kW _e
Turbine-Generator Plant (Peaker):	
150 MW _e	\$430/kW _e
100 MW _e	\$450/kW _e
50 MW _e	\$495/kW _e
Electric Transmission	\$ 60/kW _e -100 miles
FBC:	
450 MW _t	\$105/kW _t
300 MW _t	\$120/kW _t
150 MW _t	\$160/kW _t
30 MW _t	\$310/kW _t
15 MW _t	\$430/kW _t

on a reactor power of 3000 MW_t. Fuel costs are the same as were used in Reference 11: (1) Nuclear at \$1.77/10⁶ Btu, (2) Coal at \$3.30/10⁶ Btu, and (3) Distillate at \$8.08/10⁶ Btu. These are all 30-year leveled fuel costs.

The costs of various Multiplexes (Case 1 through Case 6) are calculated by combining the information in Tables 3-1 and 3-2 with the nuclear fuel cost noted. A constant O&M charge of \$20 × 10⁶ per year was included. The results of the cost calculations are summarized in Table 3-3 based on a fixed charge rate of 0.165.

Examination of the last two rows of Table 3-3 shows that, for the same electric energy costs, the maximum variation of TCP energy cost is 1 percent. It is therefore concluded that the joint product costs

Table 3-3
HTR MULTIPLEX COSTS

Item	Case Number					
	1	2	3	4	5	6
Nuclear Plant	930	930	930	930	930	930
Steam Generator	180	150	120	90	60	24
Steam Reformer Plant	—	53	105	158	210	273
Turbine-Generator Plant (Base)	480	410	336	261	186	82
Methanator Plant	—	21	43	64	86	111
Storage	—	34	67	101	134	173
TC Pipeline	—	50	100	150	200	259
Electric Transmission	101	81	62	42	23	—
TOTAL	1691	1729	1763	1796	1829	1852
Annual Heat (TWH _t)	0	3329	6658	9987	13316	17310
Annual Electricity (TWH _e)	7849	6328	4814	3294	1773	0
Capital Charge	279	285	291	296	302	306
Fuel O&M Charge	147	147	147	147	147	147
TOTAL	426	432	438	443	449	453
Electricity (mills/kWH _e)	54.3	54.3	54.3	54.3	54.3	54.3
Industrial Heat (\$/10 ⁶ Btu)	0	7.74	7.79	7.75	7.77	7.67

are essentially independent of the ratio of electricity-to-TCP energy production for this type of Multiplex system.

3.2 UNIT SIZES

Based on current, very preliminary estimates, the total U.S. industrial heat market for TCP energy is about 5000 TWH_t (annual energy) in the year 2010. This is the new and replacement market added in the years 1995 to 2010. Of this 5000 TWH_t total, approximately half is located in the 32 largest Standard Metropolitan Statistical Areas (SMSAs). The smallest of these SMSAs could absorb about 20 TWH_t per year.

Table 3-4 summarizes some preliminary analyses relating the combined industrial heat plus peaking and mid-range electric markets. These values are based on very rough assumptions concerning capacity factors, fraction of peaking and mid-range energy, etc. The results are, nevertheless, quite instructive. Note that without cogeneration, the largest amount of nuclear power is about 7000 MW, and this system exceeds 20 TWH_t per year for the industrial heat market. A more realistic value appears to be about 4000 MW_t. If cogeneration is used extensively, this decreases to about 3000 MW_t.

System reliability considerations lead to the conclusion that a minimum of three nuclear units and, preferably, four or more should comprise a system. Thus, it is concluded that the preferred unit size for an HTR Multiplex is of the order of 1000 MW_t.

For ammonia and methanol production, the largest plants (1000 tons per day) would require a nuclear heat input of less than 800 MW_t.

In addition to the above market factors, other considerations lead to a similar conclusion. Specifically, the safety characteristics of a PBR are a strong function of power level and size. The AVR, for example, can be (and has been) shut down by simply shutting off the coolant flow. Thus, a 1000 MW_t PBR is expected to have enhanced safety characteristics as compared to a larger size reactor.

Table 3-4
ANNUAL ENERGY ESTIMATES

(Without Cogeneration)

Utility Size (GW _t)	Peaking and Mid-Range Capacity (MW _t)	Dispersed Heat Capacity (MW _t)	Peaking and Mid-Range Energy (TWH _t)	Dispersed Heat Energy (TWH _t)	Total TCP Energy (TWH _t)	Nuclear Power (MW _t)
8.5	2500	1500	14.60	13.14	27.74	4950
8.5	2500	3000	14.60	26.28	40.88	7290
3.4	1000	1500	5.83	13.14	18.97	3380
3.4	1000	3000	5.83	26.28	32.11	5730
8.5	2500	750	14.60	6.57	21.17	3780
3.4	1000	750	5.83	6.57	12.40	2210

(With Cogeneration)

8.5	2500	2000	—	17.52	21.90	3910
6.8	2000	1600	—	14.02	17.52	3120
3.4	1000	800	—	7.00	8.75	1560

In summary, the preferred unit size for an HTR Multiplex system cannot be ascertained by consideration of market factors alone. It should be as small as possible consistent with practical economics. Based on currently available information, it is estimated that the preferred unit size should be about 1000 MW.

3.3 SENSITIVITY CALCULATIONS

For the HTR Multiplex-TCP system, some preliminary cost sensitivity analyses were performed. These are summarized in Table 3-5.

An examination of Table 3-5 shows that the product costs of the HTR Multiplex are relatively insensitive to pipeline and storage cost estimates. In comparing the Multiplex system with FBC systems, the comparison is sensitive to both relative fuel costs (coal versus nuclear) and average system capacity factor.

Market comparisons are also sensitive to system capacity factor for the peaking electric market; but sensitive to the cost of peaking turbine generator plants only when the size becomes small enough for the FBC to become a large fraction of the cost of the fossil system. This is probably in the 5 MW_e to 20 MW_e range which is normally below the size range of interest to electric utilities. However, this means that if cogeneration systems are implemented, the HTR Multiplex has a very large cost advantage compared to FBC systems.

Table 3-5
SENSITIVITY

Item	Change in Cost of Item	Change in Product Cost
Pipeline	± 50%	± 5%
Storage	± 50%	± 3%
Coal	± 50%	± 15%* ± 25%†
Nuclear Fuel	± 50%	± 10%

*Change in FBC product cost CF = 0.3.

†Change in FBC product cost CF = 0.9.

4. CONCLUSIONS AND RECOMMENDATIONS

4.1 CONCLUSIONS

4.1.1 HTR Markets

The HTR Multiplex consists of a PBR combined with a TCP. This technology without additional component development is applicable to the following markets:

- Dispersed industrial heat
- Peaking and mid-range electricity
- Ammonia and methanol production with methane feedstock
- Coal refining — production of gaseous and liquid fuels.

For the dispersed industrial heat market the HTR Multiplex has heat costs:

- Half that of FBCs operating at a capacity factor of 0.3
- Equal to that of FBCs operating at a capacity factor of 0.9.

For the peaking and mid-range electric market, the HTR Multiplex can supply electric energy at costs:

- Three-fourths that of FBCs operating at a capacity factor of 0.1
- Equal to that of FBCs operating at a capacity factor of 0.3.

If cogeneration systems are implemented, then the cost advantage of the HTR Multiplex is much larger for both the dispersed heat and peaking plus mid-range electric energy markets.

The combination of the above two markets is estimated to comprise from 300 GW_t to 400 GW_t in the 2000 to 2020 time period (about 8 quads per year).

For the ammonia and methanol markets, the HTR costs are about equal to coal and somewhat higher than methane with current fuel prices. If fossil fuel costs increase relative to nuclear, the HTR could become competitive in these markets.

Application of the HTR Multiplex technology to the coal refining markets is similar to the ammonia and methanol markets. Current economic analyses show approximate equivalence for coal and nuclear heat. However, if coal refining is implemented on a large scale in the U.S., the economics would be expected to change rapidly in favor of the HTR. Basically, coal reserves would be depleted more rapidly and coal prices would increase relative to nuclear.

4.1.2 Multiplex Characteristics

There appears to be no preferred split between electricity and TCP energy from an economic viewpoint. This is due to the fact that most of the Multiplex investment is related to the nuclear systems. For both market and safety reasons, a small unit size power plant is preferred. The size should be as small as is economically viable and is estimated to be of the order of 1000 MW_t.

4.2 RECOMMENDATIONS

It is recommended that more detailed analyses of the potential HTR Multiplex markets be performed. Emphasis should be placed on obtaining a better definition of the dispersed industrial heat market, providing better cost estimates for all systems, and developing a site-specific configuration. This should be followed by an implementation-commercialization evaluation. Such an evaluation should emphasize an evolutionary development considering the ultimate utilization of the HTR as a synthetic fuel producer.

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