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GAS REACTOR INTERNATIONAL COOPERATIVE PROGRAM

HTR-SYNFUEL APPLICATION ASSESSMENT

GENERAL ELECTRIC

ADVANCED REACTOR SYSTEMS DEPARTMENT
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ABSTRACT

This study assesses the technical, environmental and economic factors affecting the application of the High Temperature Gas-Cooled Thermal Reactor (HTR) to:

- synthetic fuel production
- displacement of fossil fuels in other industrial and chemical processes.

Synthetic fuel application considered include coal gasification, direct coal liquefaction, oil shale processing, and the upgrading of syncrude to motor fuel. In these applications the HTR is used to supply heat for hydrogen production by steam reforming as well as to supply steam and heat directly to the process.

A wide range of other industrial heat applications was also considered, with emphasis on the use of the closed-loop thermochemical energy pipeline to supply heat to dispersed industrial users. In this application syngas (H_2 + CO_2) is produced at the central station HTR by steam reforming and the gas is piped to individual methanators where typically 1000°F steam is generated at the industrial user sites. The products of methanation (CH_4 + H_2O) are piped back to the reformer at the central station HTR.

SECTION 1
EXECUTIVE SUMMARY

1.1 INTRODUCTION

The purpose of this study is twofold: (1) to assess the application of the High Temperature Gas-Cooled Reactor (HTR) both for synthetic fuel production processes and for displacing fossil fuels in other industrial and chemical processes, and (2) to provide a preliminary HTR-synfuel development plan.

Two distinct methods of near-term application with the potential of both economic advantage and fossil fuel resource conservation have been identified: (1) the HTR-Multiplex Concept, and (2) the concept of coupling a catalyzed fluidized bed coal gasifier to an HTR. The first of these concepts, utilizing the thermochemical pipeline, has been the subject of past process analysis and market assessment efforts which are both summarized and expanded upon in this study. The concept of coupling a catalyzed fluidized bed coal gasifier to an HTR is a direct result of the technical assessment performed herein of nuclear heat utilization processes. An additional HTR-Multiplex application which appears to merit further study is oil shale processing, particularly the Western shales.

The assessments performed to date do not uncover overriding concerns about the technical, environmental or economic viability of the HTR as a producer of nuclear process heat. Indeed, quite the contrary, all of these considerations indicate an immediate potential economic need for the HTR-Multiplex if the concepts identified can be demonstrated as an operating system. Accordingly, a development plan is given which leads, through demonstration, to operation in the early 2000s of a prototype commercial HTR-Multiplex System, including the reactor-steam/methane reformer primary system which is also an integral part of the coal conversion system. The HTR-Multiplex System has been identified in these studies as having a significant economic incentive over fossil fuel alternatives. Coal conversion processes utilizing nuclear heat appear to have no current economic advantage over fossil-fired coal conversion processes, but further investigation is required to better define the relative economics before a significant comparison can be made. Depending upon the coal conversion process, the coal usage can be reduced by 20% to 40% using the HTR heat source to produce hydrogen; further the environmental impact might be reduced with such a heat source.

Table 1A, Resource Impacts, shows a summary of the current results of this assessment for typical applications. Table 1B summarizes the estimated energy costs for three major markets (dispersed industrial heat and peaking electricity, methane conversion, coal conversion) for the HTR and alternative fossil-fired heat sources. Note that the HTR and fossil-fired heat sources are estimated to have equal costs for methane and coal conversion, while the HTR-Thermochemical Pipeline has a significant economic advantage for the one- and two-shift dispersed industrial heat market. Figure 1 shows pictorially the relationship of the HTR to the TCP and coal conversion processes, and summarizes the estimated savings from Tables 1A and 1B for selected market applications.

The total HTR-Multiplex capacity of 400 GW_t is based upon market and economic analysis described in this report. The total HTR capacity for the other process applications in Table 1A are arbitrary values based upon year 2000 production estimates because significant economic incentives have not been identified for the HTR application to coal and methane conversion and oil shale processing.

1.2 MARKET, RESOURCE, AND ENVIRONMENTAL ASSESSMENT SUMMARY

The HTR is potentially applicable to the following energy markets:

- Dispersed industrial heat (non-base load) -- (TCP Applications)
- Peaking and mid-range electricity -- (TCP Applications)
- Oil shale processing -- (TCP Application Plus Hydrogen Production)
- Coal refining -- production of gaseous and liquid fuels
- Ammonia and methanol production (either with coal or methane feedstock)
- Water splitting

Table IA
RESOURCE IMPACTS

Application	HTR-Synfuel Market Scenario(1,2)	Total HTR Capacity (GW_t)	Total Fossil Fuel Displaced(4)	Total Annual Ore Requirements(3) (U_3O_8 Tons/Yr)
A. HTR-TCP	Dispersed Industrial Heat and Peaking Electricity	400	Oil and Methane (10 Quads/yr)	5,600 to 24,000
B. Coal Conversion Processes				
1. SNG (Methane)	6000 MSCF/day	30	Coal (0.8 Quads/yr) (25% of feed)	400 to 1,800
2. Syngas (H_2+CO)	60,000 MSCF/day	60	Coal (1.5 Quads/yr) (40% of feed)	800 to 3,600
3. Gasoline (Indirect liquefaction) (SASOL)	2,000,000 bbls/day	75	Coal (1.8 Quads/yr) (40% of feed)	1,000 to 4,300
4. Gasoline (Direct Liquefaction (H-Coal, SRC, EDS and upgrading)	2,000,000 bbls/day	35	Coal (0.8 Quads/yr) (20% of feed)	600 to 2,700
5. Ammonia	15,000,000 tons/yr	12	Coal (0.3 Quads/yr) (60% of feed)	200 to 800
C. Methane Conversion				
1. Ammonia	15,000,000 tons/yr	7	Methane (0.2 Quads/yr) (40% of feed)	100 to 400
2. Methanol	200,000,000 tons/yr	60	Methane (1.5 Quads/yr) (30% of feed)	800 to 3,600
D. Oil Shale Processing TCP and Hydrogen Production Application)				
1. Western	2,000,000 bbls/day (Arabian Light Crude equivalent)	20	Coal and Shale Oil (0.4 quads/yr) (25% of feed)	300 to 1,200
2. Eastern	2,000,000 bbls/day	40	(0.8 quads/yr) (50% of feed)	600 to 2,400

NOTES

(1) Based upon year 2000 projections

(2) Typical plant sizes are: Ammonia - 10^6 tons/year/plant; SNG-200 MSCF/day/plant; Gasoline-50,000 bbl/day/plant

(3) Range based upon possible HTR and fuel cycle designs. First core load requirement varies from 170 to 250 tons U_3O_8/GW_t.

(4) Composite evaluations of various specific processes considered for each application.

Table 1B
PRODUCT COST
(1978 Dollars - Levelized Fuel)

Market	HTR-Multiplex	FBC	Distillate± GT	Oil From Coal	Coal	Methane	Methane From Coal	Medium and Low Btu Gas From Coal
Industrial Heat and Electricity								
*Peaking and Mid-Range Electricity, CF=0.10 (Mills/kWh$_e$)	115	136	89	133	--	--	--	--
*Peaking and Mid-Range Electricity, CF=0.20 (Mills/kWh$_e$)	86	83	73	107	--	--	--	--
+Dispersed Industrial Heat, CF=0.3 (\$/10^6 Btu)	6.0	9.0	--	10.0	--	--	10.0	8.0-7.0
+Dispersed Industrial Heat, CF=0.9 (\$/10^6 Btu)	6.0	5.0	--	9.0	--	--	9.0	7.0-6.0
Methane Conversion								
Ammonia (\$/10^6 Btu)	8.0	--	--	--	--	7.0	--	--
Methanol (\$/10^6 Btu)	8.0	--	--	--	--	7.0	--	--
Coal Conversion								
Coal Liquefaction (\$/10^6 Btu)	8.0	--	--	--	8.0	--	--	--
Coal Gasification (\$/10^6 Btu)	8.0	--	--	--	8.0	--	--	--

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* T-G 100 MW$_e$
\+ 15 MW$_t$
± \$15/bbl

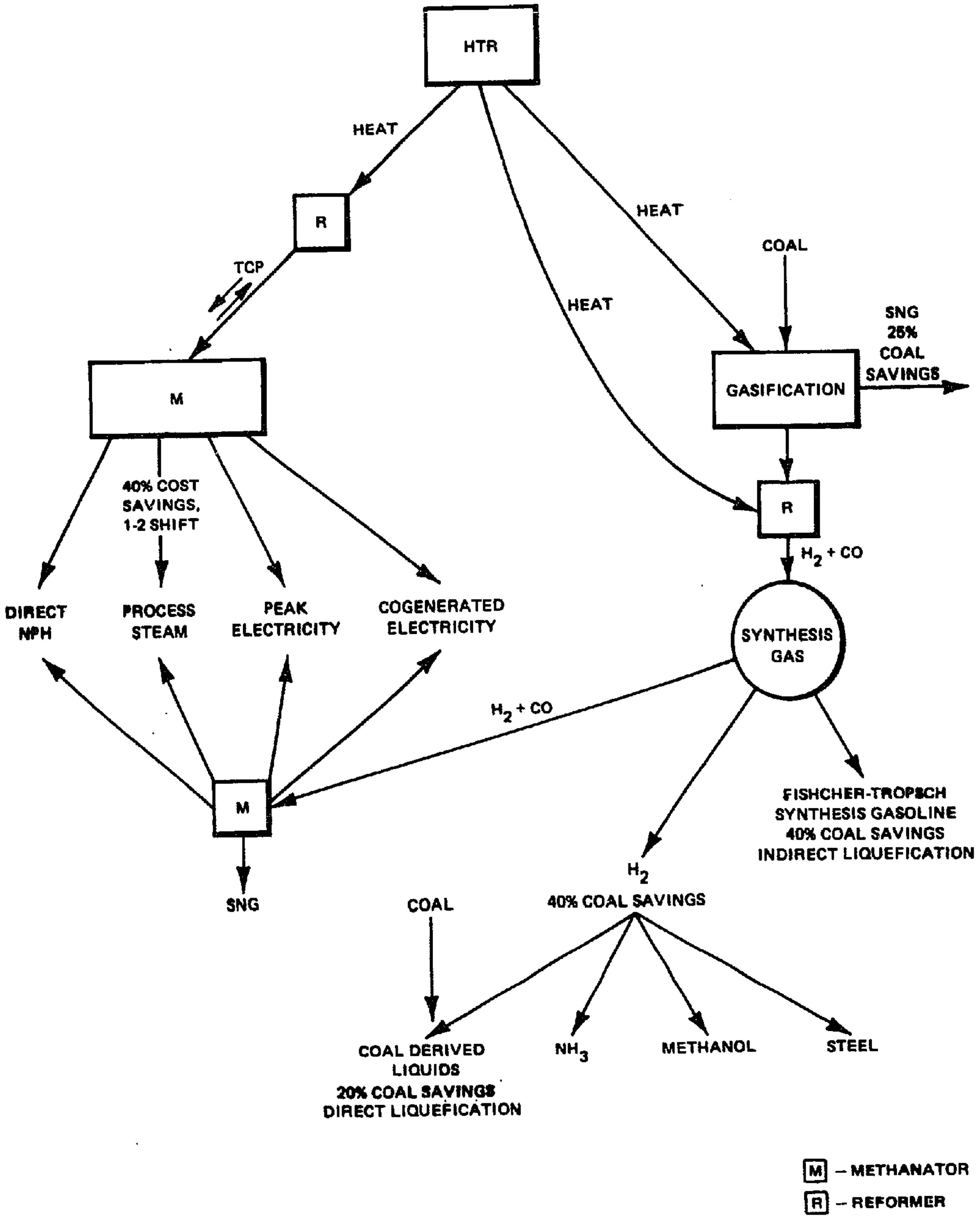

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Figure 1. APPLICATIONS OF HIGH TEMPERATURE NUCLEAR PROCESS HEAT

The Thermochemical Pipeline System

A concept that combines the HTR with a thermochemical pipeline (TCP) (the HTR-Multiplex) appears to be an effective way to utilize the HTR in serving multiple energy markets and is of particular interest in the near term. Markets for end use methanator heat consist primarily of dispersed industrial heat users, peaking and mid-range electricity production, and shale oil processing. The methanators can be considered as a replacement for current industrial boilers (oil-fired and gas-fired) and for distillate fuel burning in electric generators (gas turbine or combined cycle).

Analyses indicate that the HTR-Multiplex can supply energy at costs from two-thirds to three-fourths those of available alternatives in two U.S. markets. These markets consist of dispersed industrial heat users (one-and two-shift) plus peaking and mid-range electric power generation systems. In the 2000 to 2020 time period, it is estimated that these potential markets will total approximately 500 GW_t. This amounts to about 12 quads per year of nuclear energy substitution for fossil fuels.

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 these markets is estimated to comprise approximately 400 GW_t in the 2000 to 2020 time period (about 9 quads per year), with a potential energy savings, through cogeneration of 100 GW_t, or about 3 quads per year.

Based on the information now available, the HTR-Multiplex system appears to compare very favorably with other modes of energy supply in the future context. Because much of the technology is novel, reliable cost estimates will be difficult to obtain until more development work is completed. Further the institutional requirements of the HTR-Multiplex must be evaluated to confirm the broad application of the concept. This is also true of the competing technologies, therefore 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 if acceptable standards of living are to be maintained, energy supply to industry will have to be ensured. The HTR-Multiplex concept appears to be a promising way of achieving that goal.

Synthetic Fuel Conversion

The application of HTR process heat technology to the various coal refining markets initially indicates that product costs in the U.S. are about equal to those evolved from using coal as a heat source and somewhat higher if methane is similarly used. The coupling of the HTR to the catalyzed fluidized bed coal gasifier for the production of synthesis gas appears to change this balance in favor of the HTR in several applications, providing a highly flexible resource - synthesis gas - which allows one to produce hydrogen, ammonia, petroleum and coal refinery products and contribute directly to the production of steel.

As coal refining is implemented on a large scale in the U.S., the economics would be expected to shift more strongly in favor of the HTR. Basically, coal resources would be depleted more rapidly (20% to 40% without the HTR in most processes) and coal prices would increase relative to nuclear fuels. The potential therefore exists to develop optimized systems in which nuclear process heat can be integrated into an economically competitive coal conversion systems. Further study is recommended on using the HTR as a prime heat source for converting coal to synthesis gas.

Oil Shale

The processing of both Eastern (Devonian) (see Appendix B) and Western U.S. oil shales has been considered briefly and is planned to be a continuing subject of future work.

The geographical location of Western oil shale deposits lends itself to use of a central heat and power facility: plants for developing the oil shale would be within a 20 or 25 mile radius of a centrally sited HTR-Multiplex, located on Federal land.

Use of nuclear heat could release for sale substantial (20% to 30% of plant output) amounts of hydrocarbon products which would otherwise be used in recovery and processing. Nuclear heat could also make unnecessary the development of facilities for transporting and handling coal and its waste products after combustion and scrubbing, and could substantially reduce air pollution caused by combustion of oil shale products.

The extent to which various energy forms from the HTR-Multiplex might be substituted for fossil fuels in oil shale products can only be ascertained by further study of mining, retorting, upgrading, and refinery operations currently required for such processes. The potential appears significant enough to justify further analysis.

Industry Assessment

A review of the potential of the HTR as a process heat source is being conducted among selected suppliers and users of nuclear process heat - utilities, oil companies, gas transmission companies, architect engineers and institutional organizations - to obtain their critical commentary and indications of future potential support. In summary, interest exists in alternate forms of process heat for fossil fuel conservation and conversion, but active support depends upon the degree and aggressiveness with which the DOE sponsors the initial stages of development of HTR process heat concepts. This posture is due in large part to: (1) the very near term goals of fossil energy suppliers and users, which are oriented to the development of commercial energy resources over the next 5-10 years; - and (2) the assumption that longer range energy resource development, with commercialization not occurring until the 2000-2020 period, should intially be stimulated by the Federal Government with its greater resource capabilities for such long range projects of potential national need.

The following are major areas of commentary:

- o The concept of the HTR-Multiplex must be demonstrated by identifying a site specific need and by operating a test (prototype) plant. There will be difficulty in establishing owner and user support because of the lack of precedent for this system and the diverse nature of potential industrial process heat users. Workable solutions to the political, institutional and regulatory issues must be found before industrial participants would be willing to assume a significant financial part in the initial deployment of an HTR-Multiplex System.

- Concepts of the HTR as a source of process heat for coal conversion still must be identified and developed that have a real economic and environmental advantage over comparable fossil fired coal conversion processes. The details of this report suggest possible HTR-coal conversion systems that may offer the needed advantage. Existing conversion process systems appear to have only a fossil resource conservation incentive and no economic or technical incentives to utilize nuclear process heat over existing conventional energy sources.

- Several industrial and electric utility contacts are interested in the concept of participating in DOE-sponsored programs to further define and develop specific areas of the HTR as a process heat source. However, the degree of participation has not been defined.

- A willingness exists to support in the Congress the further development of nuclear process heat concepts which are a part of a well-defined and organized program structure.

Environmental Impact

With regard to the future, anything much short of abandonment of existing clear air regulations will continue to make industrial growth dependent on fossil fuel as an energy source very difficult and expensive even without a shift from oil or gas to coal. As industry is forced to switch from burning oil to burning coal, prevention of significant deterioration of air quality will require expensive new facilities.

The alternative is the increasing manufacture and use of clean fuels of the future which might include coal-derived synthetics or hydrogen. However, even though coal-derived organic fuels presumably would contain no ash and negligible amounts of sulfur, the combustion process would require careful control to insure that emissions of nitrogen oxides, carbon monoxide and hydrocarbons are within allowable limits.

The definition of air pollutant emission may even be broadened to include CO_2 and the possibility of its "greenhouse effect" and impact on the earth's climate.

As is exhibited in Table 2, the TCP system is environmentally benign. When comparison is made of TCP heat substituted for other fuels at the point of use, estimates show environmental impact is lessened. Table 2 summarizes the most important of these total residuals for residual oil, coal, and the HTR-Multiplex based on a thorium fuel cycle. The "Land" category includes the area required for fuel storage and heat generation. The annual increment is the surface area disturbed per year by mining. "Resources Used" refers to the total energy and water requirements to mine, process and transport the fuel and to transport and dispose of the waste. The health impacts of the gaseous and radioactive effluents were not calculated since these impacts are highly site-dependent. However, various studies indicate that the "Social Costs" for coal and uranium fuel cycles, which include soiling costs and changes to property value as well as health costs, are comparable (assuming complete SO_2 scrubbing for the coal cycle). The uranium and thorium fuel cycles have much in common, so the environmental impacts should be similar. If the entire fuel cycle is considered the HTR-Multiplex system produces less total environmental residuals than do systems based on burning coal or residual fuel oil. Closed-loop methanation of TCP gas would produce no routine pollutant emissions.

In conclusion, the preferred U.S. near term economic market application of the HTR is in the form of an HTR-Multiplex initially serving the dispersed industrial heat market (one- and two-shift) plus the peaking and mid-range electric energy market. The HTR may have a longer term application to coal conversion processes (synfuels) as coal prices rise and as coal environmental impact concerns

Table 2
COMPARISON OF ALTERNATIVE PROCESS HEAT SOURCES

Total annual environmental effects due to the complete fuel cycle for a 1000 MW_t. Includes mining, processing, transport, conversion, reprocessing, and waste disposal.

	Residual Fuel Oil	Coal	HTR-MULTIPLEX
Land			
Temporarily Committed (acres)	630	8800	390
Annual Use	70	291	4.7
Occupational Accidents			
Fatalities	0.06	0.43	0.04
Injuries	5.04	18.43	2.56
Man Days Lost	679	3640	374
Resources Used (Excluding Process Fuel)			
Process Heat (Billion kW_t/yr)	6.9	6.9	8.43
Electrical Energy (Million kW_e/yr)	26.4	39.4	106.3
Process Water (Million gal/yr)	690	570	36
Other Water(a) (Million gal/yr)	3900	6643	--
Effluents			
Particulates (T/yr)	10,200	106,300	3150
SO_x (T/yr)	15,200	47,200	1400
NO_x (T/yr)	10,240	10,600	320
CO_2 (T/yr)	1.8×10^6	2.2×10^6	36
Radioactivity to Atmosphere (Ci)	2×10^{-4}	1.34	160(b)
Tritium	--	--	--(d)
^{85}Kr	--	--	--(c)
Radioactivity to Water (Ci)	--	--	135
Solid Wastes (T/yr)	86.9	39(c)	70

Notes: (a) Required to dilute liquid wastes to acceptable standards.

(b) Excluding ^3H and ^{85}Kr

(c) Excludes mine spoil and beneficiation

(d) Negligible impact based on current ORNL fission gas release specifications for fuel reprocessing cycles under development. If ^3H and ^{85}Kr were allowed to escape to the environment their impacts would be 6153 Ci - ^3H and 219, 230 Ci ^{85}Kr for a 1000 MW_t year.

increase. Innovative development of HTR/coal conversion processes potentially can foreshorten the period before commercial acceptance. The application of the HTR to oil shale processing appears promising and should be investigated further.

1.3 TECHNICAL ASSESSMENT OVERVIEW

Nuclear Heat Utilization Processes

Coal Gasification

In this area of nuclear-assisted coal processing, essentially one key coupling has been identified. This is the catalyzed fluidized bed coal gasifier as exemplified by the Exxon process for production of methane. Its advantages are that it operates at temperatures as low as 700°C and it does not require the direct transfer of heat into a corrosive atmosphere. The HTR heat is used to pre-heat the feed materials (steam and recycled H_2 and CO) to 700°C for the gasifier, and for other plant power requirements.

Synthesis gas (syngas), a mixture of carbon monoxide and hydrogen, rather than substitute natural gas (SNG), or methane, has been identified as the best candidate for distribution from the coal processing plant. This is because it represents the opportunity to add the high temperature nuclear process heat in the endothermic formation of hydrogen and carbon monoxide and to release this energy at remote methanating plants with the option of also distributing SNG at these points. Furthermore, synthesis gas is a highly flexible resource allowing one to make hydrogen, ammonia, petroleum and coal refinery products and contribute directly to the production of steel. Thus the catalytic gasifier, producing methane, is coupled with the HTR steam/methane reformer plant to produce synthesis gas, with the HTR also providing pre-heat for the catalytic gasifier feed materials.

There is a tradeoff between the problem of developing higher temperature materials versus the advantages accrued in those processes using the higher temperature heat. This study has concentrated on the latter and has found that there are significant reasons to be attracted to the reactor system with a 950°C helium coolant outlet temperature for producing hydrogen (syngas). If a ΔT of

125°C is assumed from the primary helium to the process gas, then the temperature levels favor a 950°C reactor outlet temperature for both an increased once-through conversion efficiency (thus less inert gases to pump or recycle) and the reduced quantities of steam raised to assist in the reactions. The steam utilization is a major factor in the methane based system.

The catalytic coal gasifier system is under development and not all of the process characteristics are available in the open literature. However, estimates were made which indicate that a combination of a nuclear heat supply, a steam reformer, and a catalytic gasification system producing a syngas product would require approximately 40% less coal per unit energy output than a conventional catalytic gasifier producing a SNG product. Thus, both waste emissions and coal consumption would be reduced by approximately 40%.

Three major portions of the nuclear heated catalytic gasification system are yet to be fully developed. The gasifier has only been run at a pilot plant scale. Experimental results show that the catalyst appears effective. However, a broad program is needed to prove the effects of scale-up and to determine if there are more efficient and economic catalysts which might be employed. The reformer presents a major materials problem in that materials of construction that will survive the reducing environment for the 30 year period required for licensing have not yet been identified. Work is currently underway in both the U.S. and Federal Republic of Germany (FRG) aimed at identifying candidate materials for this application. Experimental work in the FRG on the Pebble Bed Reactor (PBR) and DOE-sponsored development work have laid the basis for application of the HTR to nuclear process heat (NPH) applications. If a major program in NPH is undertaken in the U.S., each of these three areas must be included in the investigation.

In addition to the catalytic fluidized bed (Exxon) gasifier, both the entrained bed (Texaco) and moving bed (Lurgi) gasifiers were considered.

In these latter two gasifiers, application of nuclear heat requires transfer of heat directly to the reaction bed to replace coal combustion heat. Because of high temperatures and highly corrosive conditions these applications are not believed practicable. However, the Lurgi process does operate at a lower temperature than the entrained bed process.

For production of methane from coal, the athermal catalytic gasifier may be superior to the exothermic hydrogasifier being developed for HTR application in the FRG. The exothermic hydrogasifier requires hydrogen feed from an HTR-steam/methane reformer (850°C process temperature) while the athermal catalytic gasifier requires only pre-heating the reaction gas feed materials (700°C process temperature) and recycling the potassium carbonate catalyst.

Direct Coal Liquefaction

The application of HTR heat to direct coal liquefaction (H-coal, Solvent Refined Coal (SRC), Exxon Donor Solvent (EDS) processes) has also been investigated. A key to successful coupling of the HTR and the various liquefaction processes is the production of hydrogen from coal using the catalytic gasification/-nuclear reformer concept developed previously. Here a process has been outlined for the production of 95% pure H_2 for use in liquefaction. This purity was chosen arbitrarily and the optimum purity would have to be chosen by a more detailed design. The liquefaction processes themselves would require a minimum of modification in order to match up with an HTR. Heat exchange to the processes where needed could be supplied by steam generated from the primary helium coolant from the HTR. Again it should be noted that a significant portion of the process heat might be obtained from a light water reactor (LWR). However, again the temperatures required to produce the hydrogen in the gasifier could only be achieved by an HTR.

The analysis performed here indicates that 10 to 15% of the coal used in the conventional process could be substituted by nuclear heat. This is significantly less than in the analysis of the coal gasification processes. This is not surprising since the majority of the coal feed is converted to coal liquids and the generation of H_2 consumes a relatively small portion of the coal feed.

The cases chosen here produce products that range in quality from a boiler fuel up to a fairly select product of naphtha. The quality of the product is directly related to the amount of hydrogen added to the coal and the coal saved in the process is in turn related to the hydrogen consumption. Therefore, the amount of coal saved is greater for higher quality products and less for the lower quality products. Each of the processes considered here can operate over a range of process conditions to produce a range of products. Therefore, hydrogen requirements and coal savings can vary from process to process. Generally, the range of coal savings for any of the processes would fall within the 10-15% value calculated here.

Once the liquids are formed, they must be further refined if they are converted into gasoline. In order to accomplish this refining additional hydrogen must be added to the coal "crude" and, in general, the hydrogen for this step could also be produced by the catalytic gasification/nuclear reformer. Even more coal could be saved in this process, so that the overall coal savings in converting coal to gasoline would probably be of the order of 20%.

A critical economic issue in the application of nuclear heat to synfuels production is the availability of the HTR heat source. A rough estimate shows that the potential annual fuel cost savings using nuclear heat in place of coal would be offset by a 5% to 10% loss in plant availability. Thus it appears imperative to maximize the plant availability.

Ammonia/Hydrogen Production

The key element of a nuclear based ammonia process is the production of pure (less than 10 ppm CO) hydrogen from coal using the HTR-reformer-catalytic gasifier plant. Once this pure hydrogen is obtained, it would be fed to a modified ammonia synthesis process. The major difference between this process and the conventional process would be that air could no longer be used as the source of nitrogen, since the oxygen present is no longer needed for the partial oxidation reaction. Therefore, an air separation plant is added to produce a pure nitrogen product for use in the synthesis reaction. An enriched air or oxygen byproduct would be available for sale, or if no market existed would be vented. Once the nitrogen is obtained, it is compressed to a pressure equivalent to that of the feed hydrogen and then mixed with it. This mixture is then compressed to reaction pressure and fed to a process essentially equivalent to existing synthesis processes.

Major energy consuming operations include the compression of the reactants to pressure and the refrigeration of the product stream to increase the recovery of ammonia from the recycle N_2/H_2 mixture.

Although the processes were not evaluated in detail, it is obvious that the viability of the nuclear based process is dependent on the cost of nuclear heat, coal, and the nitrogen separation as compared to the cost of natural gas. Assuming that the nuclear based process can be designed as efficiently as the conventional process, the lower cost of both coal and nuclear heat make this route attractive as a means of producing ammonia. Again it should be noted that the key use of HTR heat is in the manufacture of hydrogen where the conversion in the reformer is drastically affected by the temperature of the gas reactor coolant.

Finally, no direct heat applications of NPH have been identified (e.g., cement and lime production). In the main these processes are beyond the reach of the presently envisaged HTRs because of HTR temperature limitations.

HTR In Process Heat Application

The HTR is considered for process heat applications because of its high temperature capability, and the higher the achievable helium outlet temperature, the greater the number of processes for which it is adaptable. There are two primary circuit concepts considered for process heat applications: one uses an intermediate heat exchanger (IHX) so that the primary coolant does not flow through the reformer and steam generator (indirect cycle), while the other has the reformer and steam generator in the primary circuit (direct cycle). The use of an IHX in the primary circuit generally reduces the helium temperature available for the chemical process by about 50°C relative to the direct cycle. The reasons for using an IHX are both operationally and safety related. Safety considerations are affected since the IHX and secondary helium system provide additional separation of the process gas from the primary coolant circuit. This would be important for the thermochemical pipeline application in which the process gas is transported off-site without intervening systems. In addition, using an IHX avoids bringing combustible process gas into the reactor containment. Locating the reformer outside the reactor containment permits easier accessibility to process system components which require maintenance (e.g., replacing reformer catalyst). However, the secondary helium system presents serious design difficulties, particularly in the design of large diameter, high temperature piping to withstand seismic and thermal loads, and in the IHX design.

Many of the process heat applications require the use of a steam reformer to convert gaseous hydrocarbons into hydrogen, carbon monoxide, and/or carbon dioxide. Since a high temperature is desirable, it is preferable to eliminate the IHX and include the reformer in the primary circuit. The duplex tube reformer mitigates some of the safety concerns by providing double wall separation between the primary helium and the process gas; it also can permit monitoring of the gap between the two tubes to determine if leakage is occurring. Since there is little use in the reformer for helium temperatures below about 570°C, a steam generator is used downstream of the reformer to utilize the heat which is not usable in the reformer.

A power plant for process heat applications would probably produce electricity for its own use, and, in most cases, would have electricity available for off-site distribution. Table 3 shows the reactor power requirements for several major process heat applications: thermochemical pipeline, coal gasification, coal liquefaction, and ammonia production. Two coal gasification processes, the Lurgi process and the catalytic gasification process, are shown including several variations of the catalytic gasification process dependent on the temperatures in the reformer and gasifier. All of the coal gasification cases are sized to handle 12,000 tons of coal per day. Three processes are included for coal liquefaction, Solvent Refined Coal (SRC), H-Coal and the Exxon Donor Solvent (EDS), and are sized to produce 50,000 barrels of fuel per day. There is no relationship in the sizes used for the different applications. Table 3 shows the total power required for the reactor and the split between the power to the reformer and to the steam generator. The table is based on a 950°C reactor outlet temperature, a 300°C reactor inlet temperature, and a 575°C outlet temperature from the reformer. The 575°C reformer outlet is as low as practical for use in reforming, although higher temperatures could be used in the steam generator for superheating the steam.

Table 3 shows that the reformer power requirements determine the reactor size in the applications for thermochemical pipeline and catalytic gasification with an 825°C peak reformer temperature on the process side. In these applications, the processes cannot use all of the steam produced, so there is excess steam available for use in other processes or to produce electricity. The remaining processes in Table 3 determine the reactor power on the basis of the steam requirements, and the processes do not utilize all of the high temperature heat. Although it would be possible to use this high temperature heat to provide some of the steam required and reduce the reactor power required, it would waste high temperature heat that could be used for other processes. An optimized plant would probably use more than one process or produce electricity.

Note that the effect of reducing the reformer process temperature from 825°C to 700°C causes approximately a 10% increase in HTR power for the TCP case and a 25% increase in HTR power for the coal gasification case, because of the reduced chemical conversion efficiency in the reformer at the lower temperature. This penalty would appear to be acceptable for a first demonstration facility in order to permit utilizing currently available metallic materials for the reformer at the 700°C temperature.

In addition to the 10% increase in HTR power for the TCP case, reducing the reformer temperature from 825°C to 700°C also causes an estimated 43% increase in the component of heat cost ($/GJ) associated with the reformer-pipeline-methanator plant (exclusive of the HTR). Assuming a fixed HTR heat cost of $2.50/GJ, the total increase in heat cost is 15%.

These estimates of the effects of the reduction in reformer process temperature are quite crude and further work is needed to better establish these values.

Table 3
REACTOR POWER REQUIREMENTS FOR PROCESS HEAT APPLICATIONS

	Thermo Chemical Pipeline		Coal Gasification				Coal Liquefaction			Ammonia From Coal
				Catalytic Gasification						
	$T_R = 825^oC$	$T_R = 700^oC$	Lurgi	$T_G = 700^oC$ $T_R = 825^oC$	$T_G = 825^oC$ $T_R = 825^oC$	$T_G = 700^oC$ $T_R = 700^oC$	SRC	H-Coal	EDS	
Thermal Power (MWt)										
Power to Reformer*	1003	1106	1563	1294	1324	1294	590	762	794	1354
Used as Process Heat	1003	1106	846	1294	1324	1086	86	142	356	227
Unused in Process	0	0	717	0	0	208	504	620	438	1127
Power to Steam Generator**	736	812	1146	949	971	1581	433	559	582	993
Used as Steam in Process	177	139	1146	756	820	1581	433	559	582	993
Unused Steam in Process	559	673	0	193	151	0	0	0	0	0
Total Reactor Power	1739	1918	2709	2243	2295	2875	1023	1321	1376	2347
Product										
Nature of Product	MWt or MWe		SNG	Syngas	Syngas	Syngas	Boiler fuel	Boiler fuel and fuel oil	Fuel Oil and Naptha	Ammonia
Quantity Produced										
MWt	986	980	-	-	-	-	-	-	-	-
Bbl/D	-	-	-	-	-	-	50,000	50,000	50,000	-
BTU/D	-		2.8×10^{11}	3.8×10^{11}	3.8×10^{11}	3.8×10^{11}	-	-	-	-
ST/D	-	-	-	-	-	-	-	-	-	3000
Input										
Coal Consumed, ST/D	-	-	12,000	12,000	12,000	12,000	18,300	17,200	19,500	2100

Notes:
T_R = Peak Temperature on Process Side in Reformer
T_G = Peak Temperature in Gasifier
* Heat Available at Temperatures Above 575°C (1067°F)
** Heat Available at Temperatures Below 575°C (1067°F)

In summary, special requirements for the HTR for process heat applications beyond those for steam-electric cycles include:

- a higher outlet helium temperature
- the addition of a steam reformer in the helium coolant circuit upstream from the steam generator
- a potential safety requirement for an intermediate helium circuit to keep the process gas outside of the reactor containment building
- a higher required power availability and possibly a power source back up because of initial lack of interconnected system of plants (process gas "grid") similar to electrical grid.
- different duty cycles and design basis events associated with process gas application, in addition to those imposed by the steam-electric system for the Multiplex plant.

1.4 NUCLEAR FUEL CYCLE SUMMARY

The nuclear fuel cycle studies were all based on the conversion of thorium to fissionable uranium-233 (U-233) using fuel enriched in U-235 or U-233 as a feed material. The high neutron efficiency of U-233 makes it particularly well suited for use in graphite moderated reactors. The high conversion efficiency of the U-Th cycle helps to minimize the annual fuel requirements and fuel costs of the PBR.

Four basic fuel cycles are of current worldwide interest. Two of these cycles are "stow away" cycles in which the fuel elements are stored without immediate reprocessing once they achieve their final burnup. Feed material for these cycles is a mixture of either highly enriched uranium (HEU) or medium enriched uranium (MEU) particles (as oxide or carbide)mixed with enough Th-232 particles to provide the desired feed enrichment. The MEU feed option is of interest solely because the uranium feed material is not useful for use in weapons manufacture. The two remaining fuel cycles involve reprocessing and recycling of the spent fuel. The feed enrichment is achieved with either U-233 or U-235 makeup (HEU). With recycle the uranium ore requirements are reduced relative to the "stow away" cycles, however the front-end of the fuel cycle requires remote handling because of the activity of the U-234 decay products. In this report the fuel cycles with no reprocessing will be referred to as "Once-Through". This is not to be confused with the "Once-Through Then Out" or OTTO fuel management scheme in which the fuel achieves its discharge exposure in one pass through the core. The fuel cycles with reprocessing and recycling will be referred to as Recycle. All fuel cycles considered are of the OTTO type.

For this study, two designs have been selected for each fuel cycle to show the range of expected fuel parameters which might occur. The lower bound represents fuel designs which approximate the characteristics of current Thorium-High Temperature Reactor (THTR) fuels; the upper bound represents an improvement in one of the design characteristics of the current THTR fuels, usually the heavy metal loading per ball. Neither the upper nor lower bound are intended to show maximum or minimum characteristics but rather characteristics which might reasonably be expected.

The Once-Through MEU fuel designs are characterized by high fossil burnups (100,000 MWD/MT) with medium enriched uranium used both as a first core and reload core fuel. The designs were developed to minimize proliferation risks while still maintaining a high burnup, and THTR and Arbeitsgemeinschaft Versuchsreaktor (AVR) fuel characteristics.

The Once-Through HEU fuel designs are representative of extended parametric research on Once-Through HEU fuel cycles in PBRs in Germany. The designs are characterized by high fissile burnups (100,000 MWD/MT) with highly enriched uranium used both as first core and reload core fuel. The designs were developed as introductory fuel designs, to be used before recycle occurred.

With fuel recycle, the PBR can recover its bred U-233 and increase the amount of U-233 in the core. The net result is fuels with a higher conversion ratio and lower uranium makeup fuel requirements. The fuel designs studied represent the equilibrium conditions that would occur after many U-235 fueled cycles had created an inventory of U-233. Once the inventory has reached equilibrium no net gain or loss of U-233 occurs, but the makeup fuel requirements are again U-235.

If U-233 is available, the above HEU recycle designs might be initially fueled by U-233 rather than by U-235, and U-233 might also be substituted as makeup fuel. With a fully enriched U-233 core, the PBR can reach its highest conversion ratio. The Recycle U-233 designs represent this high enriched Uranium-233 fuel concept. The U.S. plans to develop a plant to recover the U-233 from spent HTR fuel are not in existence. Thus initial HTR coles would be operated with U-235 as in the LWR fuel cycle.

A summary of the fuel design parameters and results are shown in Table 4.

Table 4
FUEL INFORMATION SUMMARY

	Once-Through MEU Fuels		Once-Through HEU Fuels		Recycle HEU Fuels		Recycle U-233 Fuels	
	THTR	Advanced	THTR	Advanced	THTR	Advanced	THTR*	Advanced
Fuel Recycle	No	No	No	No	Yes	Yes	Yes	Yes
U-235 (and U-233) Enrichment	20%	20%	93%	93%	93%	93%	99%	99%
Burnup (MWd_o/Kg)	100	100	100	100	23.7	32.0	35.0	35.0
Conversion Ratio	0.64	0.58	0.594	0.665	0.77	0.85	0.86	0.91
Fuel Residence Time ($days_o$)	1223	872	1217	1070	382	687	507	676
Ball Loading (gm/ball)	11.24	8.07	11.24	20.00	11.24	20.0	15.0	20.0
Carbon/Heavy Metal Ratio	325	458	325	180	325	180	240	180
Capacity Factor	80%	80%	80%	80%	80%	80%	80%	80%
One-Cycle Fuel Cycle Cost (1979 ¢/MBtu)	110	102	105	98	128	94	67	62
Equilibrium Uranium Use (ST U_3O_8/GW_{Th})	60	58	54	53	21	14	NA (55 kg U-233)	NA (44 kg U-233)

*Moderately advanced THTR fuel (higher ball loading)
NA = Not Applicable, design uses U-233 for makeup requirements.

SECTION 2

HTR-PROCESS HEAT MARKET ASSESSMENT

2.1 SUMMARY

The High Temperature Reactor (HTR) is potentially applicable to the following non-baseload energy electric markets:

- Dispersed industrial heat
- Peaking and mid-range electricity
- Ammonia and methanol production with methane feedstock
- Coal Refining - production of gaseous and liquid fuels
- Water splitting

A concept that combines the HTR with a Thermochemical Pipeline (TCP) (the HTR-Multiplex) appears to be an effective way to utilize the HTR in serving multiple energy markets and is of particular interest in the near-term. Markets for the methanator steam consist primarily of dispersed industrial heat users plus peaking and mid-range electricity production. Methanators can be considered as a replacement for current industrial boilers (oil-fired or gas-fired) and distillate fuel burning in electric generators (gas turbine or combined cycle).

Analyses indicate that the HTR-Multiplex can supply energy at costs from two-thirds to three-fourths those of available alternatives in two U.S. markets. These markets consist of dispersed industrial heat (one- and two-shift operations) plus peaking and mid-range electric power generation. In the 2000 to 2020 time period, it is estimated that these potential markets total approximately 500 GWt. This amounts to about 12 quads per year of nuclear substitution for fossil fuels.

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 approximately 400 GWt in the 2000 to 2020 time period (about 9 quads per year).

Based on the information now available, the HTR-Multiplex system appears to compare very favorably with other modes of energy supply in the future. Because much of the technology is novel, reliable cost 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 our high standard of living, energy supply to U.S. industry will have to be ensured. The HTR-Multiplex concept apears to be a promising way of achieving that goal.

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 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.

In conclusion, the preferred U.S. near-term application of the HTR is in the form of an HTR-Multiplex initially serving the dispersed industrial heat market (one- and two-shift) plus the peaking amd mid-range electric energy market.

2.2 HTR-MULTIPLEX MARKET ASSESSMENT

2.2.1 Concepts

The HTR-Multiplex concept is intended to efficiently and economically utilize the temperature capability of the HTR by producing one or more forms of storable energy plus electricity. A variety of markets could thus be served depending upon the characteristics of the storable energy form. The key feature of the system is the thermochemical pipe (TCP) - also known as the chemical heat pipe and as the EVA-ADAM system (the reformer-methanator test facility at Juelich, FRG).

Figure 2-1 is a diagram of the TCP. Thermal energy from the nuclear reactor is converted into chemical energy by using the steam-methane reaction. The resulting chemical substance (a mixture of gases) is pumped through pipelines at ambient temperatures for distances up to 300 miles. There, the chemical energy is reconverted to heat to produce steam at temperatures of up to about 590°C.

The steam-methane reactions are

$$CH_4 + H_2O \underset{\text{exothermic}}{\overset{\text{endothermic}}{\rightleftarrows}} CO + 3H_2$$

$$CH_4 + H_2O \underset{\text{exothermic}}{\overset{\text{endothermic}}{\rightleftarrows}} CO_2 + 4H_2$$

The reactions at the HTR plant steam reformer are those from left to right. At the methanators, the reactions are from right to left. The steam-reformer reaction kinetics and equilibrium characteristics are such that heat must be supplied at peak temperatures in the range of 870°C to 980°C.

The basic technology for the steam-methane reactions is well established; the pipeline energy density is adequate; the chemicals are noncorrosive; the catalyst cost is reasonable; and the reaction kinetics are fast. The methane from the methanator may be returned to the central plant reformer (closed cycle as shown in Figure 2-1) or, if a supply of methane is available at the central plant, it may be burned or used as a feedstock (open cycle).

A substantial volume of storage for gases flowing in both directions is provided by the pipelines; pressure changes ("pipeline packing") generally can smooth load changes for about a one-day period. If additional storage is required, tanks, caverns, or porous underground formations may be used. These would be located at HTR plants, in load areas, and along pipelines, to maintain pipeline flow at as high a level as possible (high capacity factor).

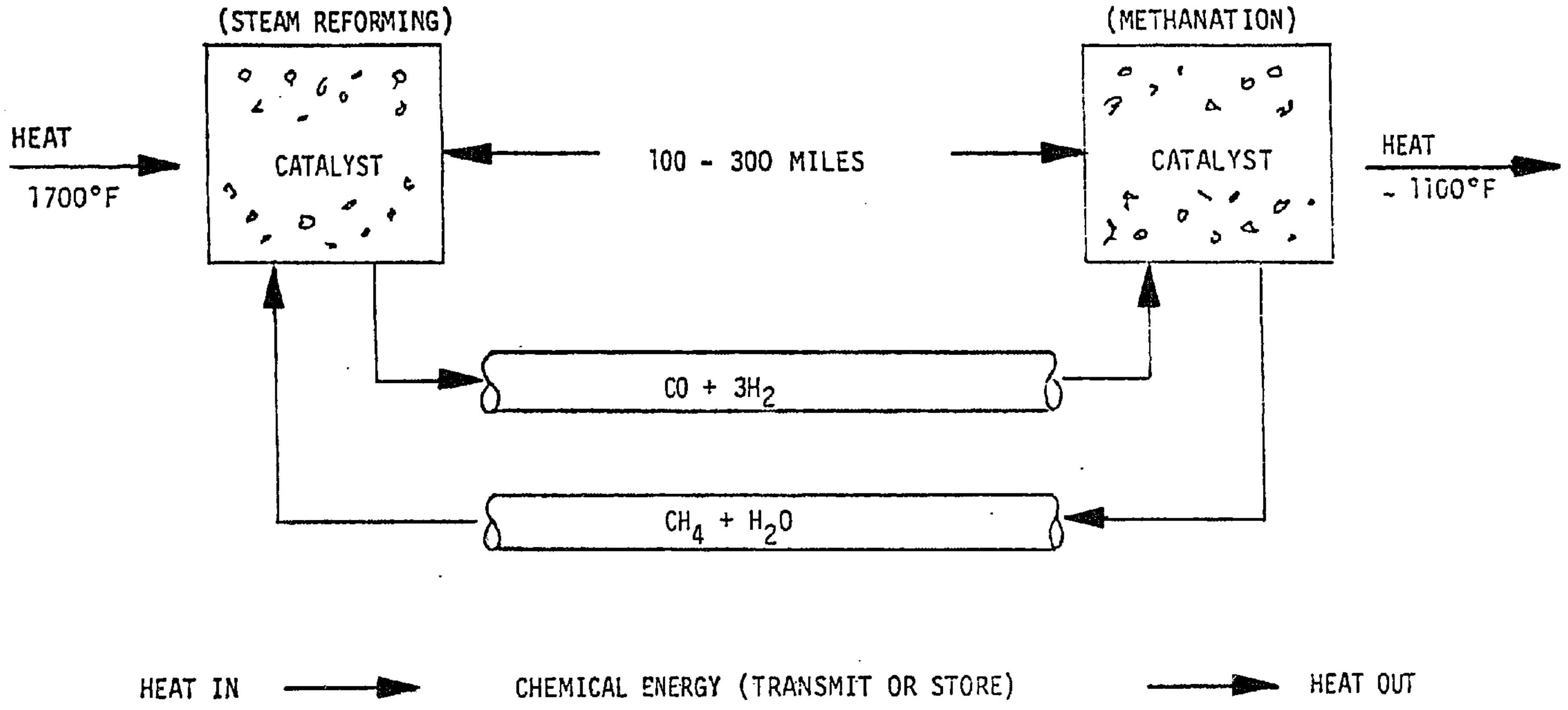

Figure 2-1. THERMOCHEMICAL PIPELINE CONCEPT

The characteristics of the reformer plant in the TCP system are such that a significant amount of low temperature heat is rejected. From a thermodynamic viewpoint, it is most appropriate to use this heat for feedwater heating of steam generators. Preliminary estimates indicate that if the excess steam is converted to electricity, the amount produced can be adjusted to that needed for system operation (including pipeline compression for about 100 miles). This specific multiplex thus produces sufficient electricity to operate the total system and delivers approximately 80% of the nuclear heat in the form 38°C of steam from methanators dispersed along the pipeline. However, the split between electricity and pipeline energy can be varied to increase the electricity produced by the nuclear reactor plant, if a base-load electrical market is available.

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-multiplex 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-Multiplex to displace fuels used under industrial boilers. There is no doubt that this is a technically feasible application, however the system configuration has not been developed in detail (e.g., small industrial catalytic boilers versus utility-sized methanators with steam distribution).

2.2.2.1 Industrial Heat

2.2.2.1.1 Overview

Of the four major sectors of the U.S. economy, the industrial sector is the largest energy consumer, accounting for 36% 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% 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 2-1 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% of the total; the top six groups for over 78%. 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.

Table 2-1
ENERGY CONSUMPTION BY INDUSTRY GROUP AND FUEL, 1976 (10^{12} Btu)

Code	Industry Group	Oil	Coal	Gas	Other	Electricity	Total
28	Chemicals	341	337	1,710	126	1,642	4,156
33	Primary Metals	314	520	959	83	1,652	3,526
26	Paper	507	221	366	49	706	1,850
29	Petroleum	96	6	1,068	21	330	1,521
32	Stone, Clay, Glass	143	301	601	63	305	1,412
20	Food	176	88	448	80	426	1,219
--	All Other	412	162	893	203	2,090	3,759
	TOTAL	1,990	1,634	6,045	626	7,150	17,444

(Values may not add due to rounding.)

Source: Calculated from Department of Commerce, 1978.(2-1)

Estimates of the fraction of fuel used under boilers for raising process steam have been assembled by Fejer and Larson(2-2) and are shown in Table 2-2. Only purchased oil, coal, and gas used for process steam are considered displaceable by the HTR-Multiplex 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 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 2-2
FUEL USED FOR PROCESS STEAM IN MANUFACTURING INDUSTRIES

Code	Industry Group	Percent By Fuel Oil	 Coal	 Gas	Consumption, 1976 (10^{12} Btu)	Percent Of Total Energy
28	Chemicals	40	75	30	902	22
33	Primary Metals	10	10	10	179	5
26	Paper	95	100	93	1,044	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	776	13-35
					4,037 (total)	23 (average)

Source: Calculated from Feger and Larson, 1974, and Table 2-5(2-2).

Projecting the process steam demand to the end of the century at a 1% annual growth rate leads to a 170 GWt 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 market limited.

2.2.2.1.2 Regional Estimates

The following data was compiled from *The Annual Survey of Manufactures, 1976*(2-1) and *Industrial Use of Energy, Appendix*(2-2). Table 2-3 shows the energy use in the 33 largest Standard Metropolitan Statistical Areas (SMSAs) energy users. These 33 SMSAs comprise 11% of the SMSAs, while they use 43% of the energy. The first two columns are the amount of energy used, given in trillions of Btu and billions of kWh respectively.

Table 2-3
ENERGY USE BY SMSA

		Amount Of Purchased Fuel In 1976 (Industry)	
		Btu x 10^{12}	kWh x 10^9
1.	Allentown-Bethlehem-Easton	58.8	17.2
2.	Baltimore	73.1	21.4
3.	Baton Rouge	221.4	64.8
4.	Beaumont-Port Arthur-Orange	310.5	91.0
5.	Birmingham	63.2	18.5
6.	Buffalo	75.8	22.2
7.	Charleston, WV	49.8	14.6
8.	Chicago	280.7	82.3
9.	Cleveland	138.4	40.6
10.	Corpus Christi	89.2	26.1
11.	Dallas-Fort Worth	57.4	16.8
12.	Detroit	216.7	63.5
13.	Galveston-Texas City	144.7	42.2
14.	Gary-Hammond-East Chicago	251.7	73.8
15.	Houston	663.2	194.3
16.	Huntington-Ashland, WV, KY, OH	66.5	19.5
17.	Kansas City	50.9	14.9
18.	Lake Charles	145.9	47.8
19.	Los Angeles-Long Beach	141.9	41.6
20.	Milwaukee	49.7	14.6
21.	Minneapolis-St. Paul	56.2	16.5
22.	New Orleans	101.1	29.6
23.	New York	71.6	21.0
24.	Newark	82.3	24.1
25.	Philadelphia	190.0	55.7
26.	Pittsburgh	280.3	82.2
27.	Riverside-San Bernardino-Ontario	52.5	15.4
28.	St. Louis	113.0	33.1
29.	San Francisco-Oakland	130.3	38.1
30.	Steubenville-Weirton	86.9	25.5
31.	Toledo	51.3	15.0
32.	Tulsa	51.5	15.1
33.	Youngstown-Warren	71.5	21.0
	TOTAL	4,488.0	1,315.0

Figure 2-2 is a map of the United States showing locations of SMSAs with the 33 largest energy users shaded darker than the rest. From the map, it can be seen that the large SMSAs in the Midwest and Northeast could be interconnected and thereby service the majority of the smaller SMSAs in the area. Interconnection of larger SMSAs also appears possible in the Texas, Oklahoma, and Louisiana area and also in California. Other areas such as the Rockies and the Southeast this interconnection does not look as feasible since there are very few large SMSAs in these areas.

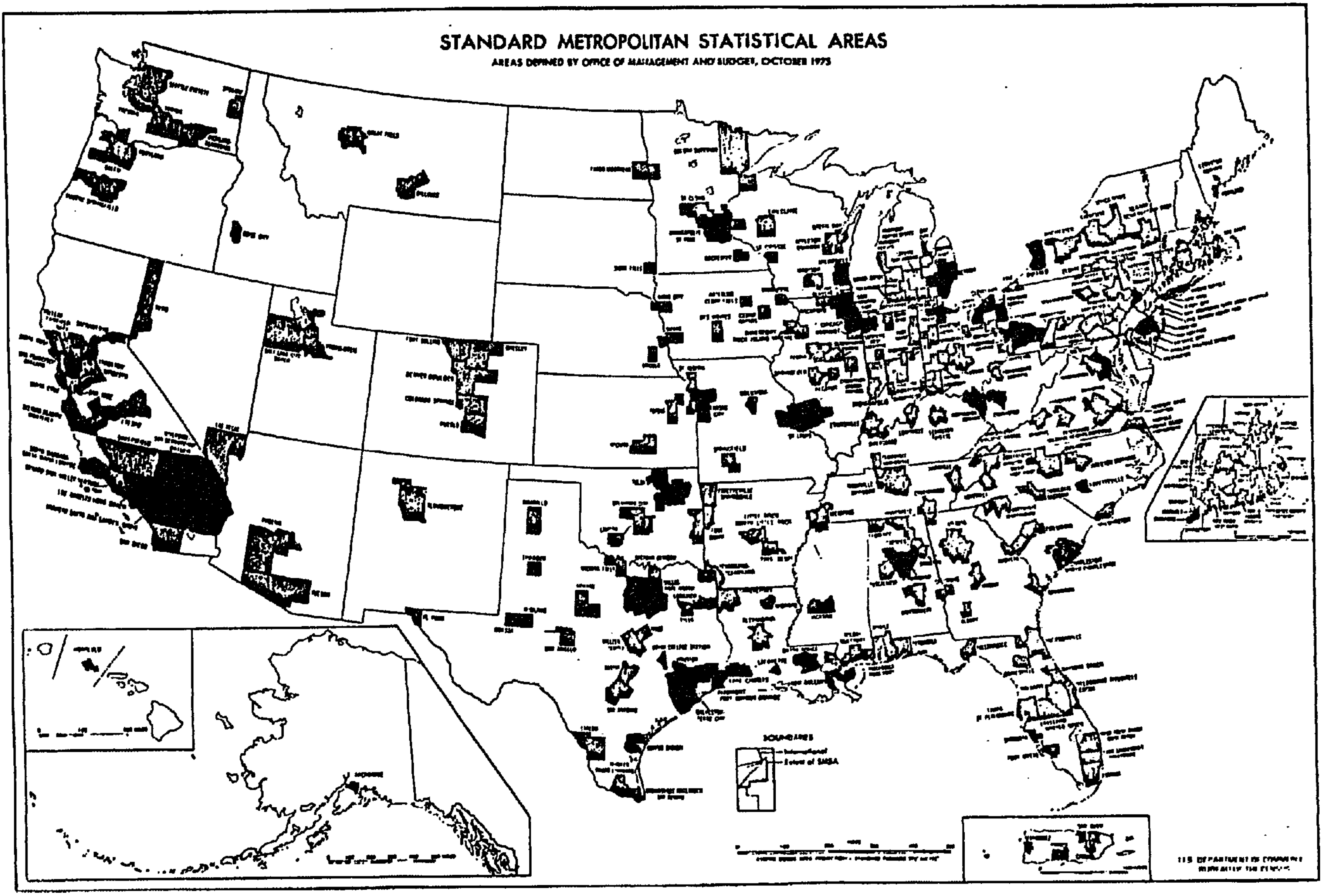

Figure 2-2. SMSA LOCATIONS

The only industry which uses a significant amount of heat under 150°C is the food industry which uses about 8% of the total industrial energy (purchased fuel) use. Since the food industry has a TCP application factor of 0.45 less than 3.5% of the industrial heat is under 150°C.

Table 2-4 shows U.S. industrial energy growth for the 1954 to 1971 period. It should be noted that from 1971 to 1976, industrial heat use actually decreased slightly from 1476×10^9 kWt to 1315×10^9 kWt in the 33 SMSAs listed in Table 2-3. This is consistent with a major industrial effort to conserve energy during these years.

Table 2-4
INDUSTRIAL ENERGY GROWTH

Time Period	Growth Rate (%)
1954-1958	1.57
1958-1962	4.30
1962-1967	3.45
1967-1971	2.37
1954-1971	2.95

The potential industrial heat market considered for the HTR-Multiplex is the sum of: installations to provide the increase in energy requirements; and installations to replace other types of systems, which have reached end of life. Assuming a 30-year life-cycle on these older systems, one-sixth of the installed capacity at the beginning of a 5-year period would be replaced during that period.

Assuming a growth rate of 2.0% per year, total U.S. industrial heat requirements in the 2000 to 2020 time period would add new and replacement capacity resulting in an annual heat requirement of about 7×10^{12} kWh in the year 2020. Of this market, approximately 58% is at temperatures below 590°C and approximately 25% is at temperatures below 590°C and operated either one- or two-shift - i.e., at capacity factors in the range of 0.3 to 0.6.

Using these factors, the potential U.S. dispersed industrial heat market in the 2000 to 2020 time period for the HTR-Multiplex is estimated to require 2×10^{12} kWt annually. This is about 7 quads per year which requires a multiplex capacity of approximately 330 GWt. If only the 33 largest SMSA's are served, the market is approximately 130 GWt.

p

2.2.2.2 Peaking and Mid-Range Electricity

Forecasts of additions to the U.S. electric energy system were obtained from the General Electric Company's Electric Utility System Engineering Department (EUSED). These forecasts are by National Electric Reliability Council (NERC) region - see Figure 2-3 and Table 2-5. Table 2-6 summarizes the electric energy growth rates on which the forecasts are based and Table 2-7 describes the forecast additions by plant type for various time periods.

Table 2-5
NERC REGIONS AND GEOGRAPHY

NERC Region	Map Region (Figure 2-3)
NPCC	NPCC
MAAC	MAAC
ECAR	ECAR
SERC - Oil SERC - Coal	SERC
WNL	MAIN + MARCA
WSC	ERCOT + SPP
PNW PSW	WSCC

For this study, the 1976-1995 additions (shown in Table 2-7) were assumed to apply for the 2000 to 2020 time period. This corresponds to an average growth rate of about 3% during this latter period and further assumes the plant mix would remain the same for each region.

Annual electric energy production by plant type for the year 2020 from the cumulative additions was calculated by using capacity factors given Table 2-8. The results are summarized in Table 2-9.

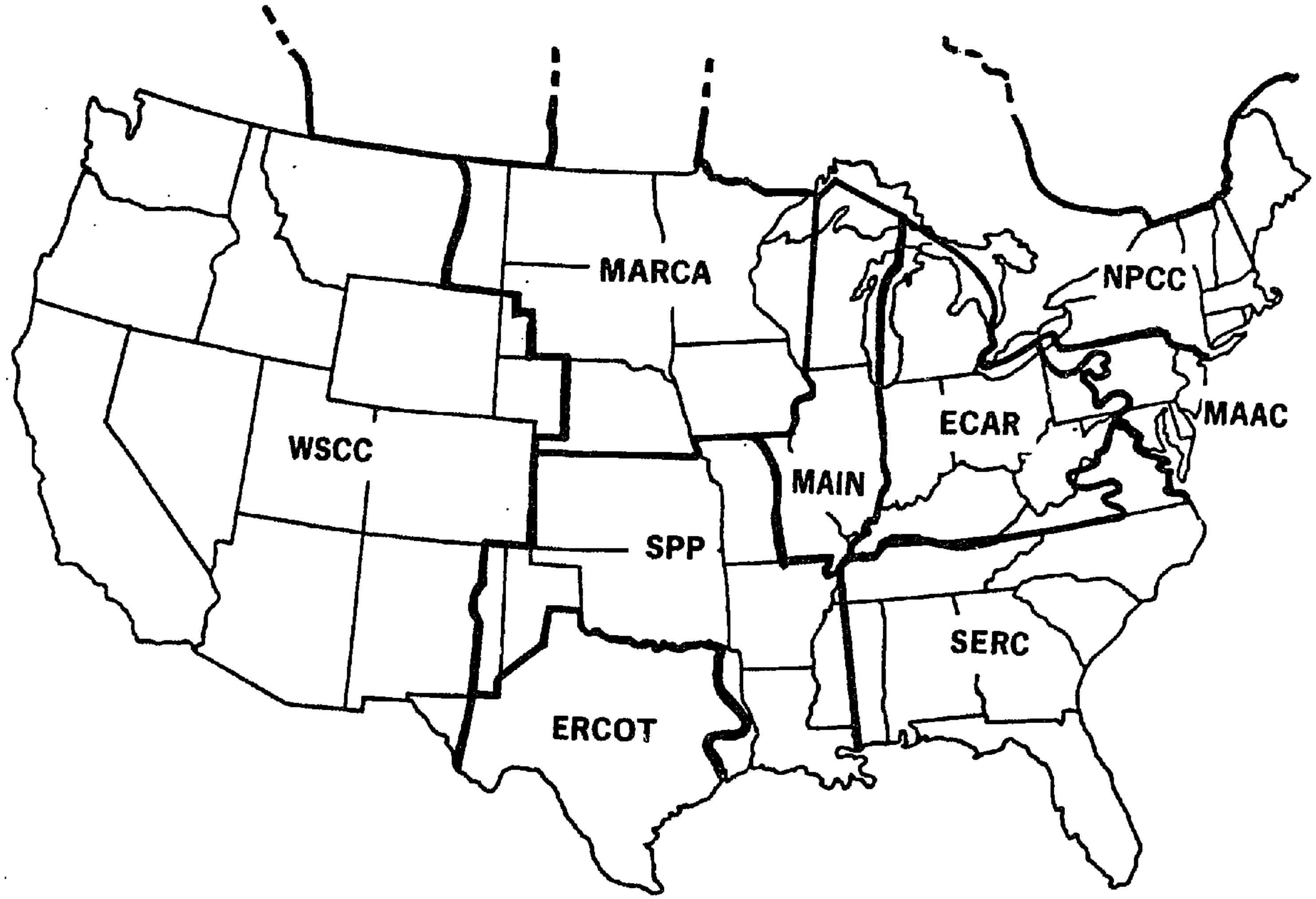

Figure 2-3. REGIONAL RELIABILITY COUNCILS OF THE NATIONAL ELECTRIC RELIABILITY COUNCIL

Table 2-6
AVERAGE PEAK LOAD GROWTH, PERCENT

Region	1976-80	1980-85	1985-90	1990-95
NPCC	3.3	3.3	3.1	2.8
ECAR	5.5	5.6	5.1	4.8
MAAC	4.3	3.6	3.2	2.8
WNC	5.0	5.0	4.3	3.9
WSC	7.0	5.9	5.1	4.8
SERC - OIL	6.6	5.6	5.5	5.0
SERC - COAL	6.3	5.5	5.3	4.8
PNW	5.3	4.9	4.1	3.8
PSW	5.3	4.9	4.1	3.8
Nation	5.1	4.9	4.5	3.8

Table 2-7
NATIONAL ECONOMIC MIX CUMULATIVE ADDITIONS BY TYPE

Additions (GW)	Nuclear	Fossil	GT	STAG	Hydro	Total
1976-1990						
NPCC	11	5	3	1	1	
MAAC	11	6	5	1	0	
ECAR	31	31	13	0	1	
SERC - OIL	13	5	1	6	4	
SERC - COAL	46	22	7	0	5	
WNC	10	28	15	0	0	
WSC	33	42	13	2	0	
PNW	12	10	4	1	8	
PSW	14	15	3	11	5	
Nation	181	165	64	22	24	456
1976-1995						
NPCC	21	5	4	1	2	
MAAC	19	7	7	2	0	
ECAR	51	52	17	0	1	
SERC - OIL	23	6	1	11	5	
SERC - COAL	79	29	10	0	7	
WNC	15	44	20	0	0	
WSC	66	46	21	4	0	
PNW	18	13	6	1	10	
PSW	20	23	3	19	6	
Nation	312	226	89	38	31	696
1991-1995						
NPCC	10	0	1	0	1	
MAAC	8	1	2	1	0	
ECAR	20	20	4	0	0	
SERC - OIL	10	1	0	5	1	
SERC - COAL	33	7	3	0	2	
WNC	5	16	5	0	0	
WSC	33	4	8	2	0	
PNW	6	3	2	0	2	
PSW	6	8	0	8	1	
Nation	131	60	25	16	7	239

Table 2-8
1995 CAPACITY FACTORS, PERCENT

Region	Nuclear	Fossil Coal	Gas Turbine	Comb. Cycle	Fossil Oil	Natural Gas
NPCC	69	72	14	30	46	--
MAAC	63	56	23	45	45	--
ECAR	68	57	25	34	33	31
SERC - OIL	68	77	16	54	50	68
SERC - COAL	69	54	29	45	29	53
WNC	70	58	18	37	33	32
WSC	68	67	11	23	48	29
PNW	64	66	5	28	29	20
PSW	66	53	9	66	59	13
Nation	67	67	18	59	47	28

Table 2-9
ELECTRIC ENERGY PRODUCTION FROM CUMULATIVE ADDITIONS (2000-2020)

	Annual Energy In 2020 ($kWh_e \times 10^{11}$)			
Region	Nuclear	Coal	GT	STAG
NPCC	1.59	0.40	0.063	0.04
MAAC	1.31	0.43	0.18	0.10
ECAR	3.80	3.25	0.46	--
SERC - OIL	1.74	0.51	0.013	0.65
SERC - COAL	5.79	1.71	0.31	--
WNC	1.15	2.80	0.41	--
WSC	4.91	3.38	0.25	0.10
PNW	1.26	0.94	0.04	0.025
PSW	1.01	1.34	0.025	0.80
TOTAL	22.56	14.75	1.75	1.71

As noted in Table 2-9, the amount of electric energy produced by distillate fuel using systems (gas turbine and combined cycle) is forecast to total 3.46×10^{11} kWhe in the year 2020. At a conversion efficiency of 0.35 this is approximately 3.3 quads per year. An HTR-Multiplex with an energy delivery efficiency of 0.80 would need to supply about 4.0 quads of TCP energy per year which corresponds to an installed capacity of about 170 GWt.

2.2.2.3 Combined Markets - Cogeneration

The HTR-Multiplex can serve as a heat source for cogeneration systems. These markets have not been evaluated in detail but can be estimated in the following way. Assume the HTR-Multiplex supplies energy for electric generators to supply the 3.46×10^{11} kWhe noted in Section 2.2.2 but operating at a thermal efficiency of 0.25. The result would be about 180 GWt of useful heat rejected by the electric cogenerators for a gross input of 240 GWt. Since the dispersed industrial heat market (Section 2.2.1) was estimated at 330 GWt, a cogeneration system would require a total HTR-Multiplex capacity of 390 GWt as compared to a non-cogeneration system of about 500 GWt.

2.2.2.4 Competitive Market Assessment

An HTR-Multiplex system based on the thermochemical pipeline (TCP) as one mode for distributing the product can produce electricity, industrial process steam, and lower grade heat for district heating at various load factors, in urban locations, with minimum polluting emissions or safety limitations. Some electricity and heat can also be made at the HTR plant. To compare the economic merit of such a system with the competing alternatives for each form of energy delivered requires a consistent and fair framework of economic assumptions.

The Electric Power Research Institute (EPRI) has issued a *Technical Assessment Guide*(2-3) that recommends a consistent set of cost assumptions and economic methodology for studies on alternative power generating systems, so that studies by different contractors of different alternatives can be better compared. General Electric has used this methodology in recent studies both for EPRI(2-5) and for DOE/NASA(2-8). The Gas Cooled Reactor Associates (GCRA) has indicated they use the EPRI data base and methodology.* This methodology will be used here.

Basically, it is a method of life-cycle costing, so that all costs - investment, fuel, and O&M - are considered over the lifetime of the system, for each competing alternative. Costs incurred in different years are placed on a common base by converting to their present worth in the initial year of operation. Capital costs incurred before operation are discounted forward to the base year; all costs incurred after the base year are discounted back to this year. This requires assumptions on the inflation

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*Private communication by Edward Sproat, III of GCRA.

and net escalation scenarios of all cost components over the period from the present to the end of the system lifetime, e.g., 30 years after the base year.

For simplicity, since a wide range of alternative scenarios are credible, the EPRI *Technical Assessment Guide* (TAG)$^{(2-3)}$ assumes a continuing basic inflation of 6%/annum from now on. This applies to all cost components unless a specific net escalation, as a percentage greater than or less than the basic inflation, is specified. Net escalation scenarios for the various fuels are given in the TAG; both capital and O&M are assumed to have no net escalation.

The cost of money at different risk levels, common and preferred stocks and bonds, is a function of the current and expected inflation. Consistent with the above scenario, the TAG suggests a discount rate of 10%.

It is conventient for utilities and other users to consider annual costs, not just a lump sum representing the present worth in the year of initial operation. Although actual costs will escalate over the life of the plant, it has become accepted practice to convert present worth of all the annual costs over the plant life to an equivalent constant, uniform or "levelized" stream of annual costs. To convert capital costs into such a stream, a fixed charge rate (FCR) is derived that considers the typical utility financial practices and some continuing charges that are capital dependent, such as insurance and property taxes. For the above scenario, FCR = 0.18. Since some components of O&M are fixed costs rather than variable costs (related to plant output level), and these average about 2-3% of the annual fixed charges, we include them in the FCR, making it 0.186.

Annual fuel costs and annual variable O&M costs are levelized by a factor dependent on the inflation rate, the discount rate, the plant life, and the net escalation rate assumed for the fuel (EPRI, TAG, pages V19-20)$^{(2-3)}$. Even with no net escalation, i.e., 6% inflation only, the fuel price in the 30th year will be 5.74 times that in the initial year. The levelized cost of fuel is intermediate between these extremes, specifically 1.89 for 6% inflation, 10% discount rate, and 30-year life.

It should be emphasized and understood that this methodology makes the cost used for fuel look almost twice as big as that used in studies that use a "current" fuel cost rather than levelized. Consequently, the cost of energy forms such as heat and electricity look higher. However, by using levelized costs not only for the system being studied but also for the alternatives considered, comparability is assured.

Cost input data used for analyzing the HTR-Multiplex and alternative systems is given in Table 2-10. The costs of the non-nuclear components of the multiplex are well known since they are, for the most part, commercially available items. The cost of the HTR is the major uncertainty. For comparison, the $235/kWt value corresponds to an HTR nuclear plant (heat only) that is about 1.6 times the cost of an equivalent PWR nuclear plant.

The HTR-Multiplex selected for analysis has characteristics as described in Table 2-11.

Operation of the HTR-Multiplex assumes that except for the methanator plants, system capacity factor is 0.80 with sufficient storage to operate the methanators at capacity factors ranging down to 0.15. Calculated heat costs are summarized in Table 2-12 based on the preliminary cost data from Table 2-10.

Examination of Table 2-12 shows that at a capacity factor of 0.9 the cost of heat from fluidized bed combustors (FBC) systems is lower than the cost of heat from the HTR-Multiplex for all unit sizes. Conversely, the HTR heat costs less than fluidized bed combustors (FBC) heat at a capacity factor of 0.15 for all unit sizes. At intermediate sizes and capacity factors relative cost comparisons become complex. Figure 2-4 shows these relationships graphically.

Table 2-13 shows a comparison between estimated heat and electricity costs for the HTR-Multiplex and those for other fossil-fired alternative heat sources; namely, fluidized bed coal combustion, petroleum, and coal-derived fluid fuels.

The conclusions derived from Table 2-13 are as follows:

- For the dispersed industrial heat market, the cost of FBC heat is from 1.25 to 1.65 that of multiplex heat for one- and two-shift industries. For three-shift industries, the FBC heat is only 0.85 that of multiplex heat. For fluid fuels from coal, the cost is approximately 1.60 that of multiplex heat and for oil about a factor of 1.05.

Table 2-10
COST DATA

Item	Cost (1978 Dollars)
Nuclear Plant	$\$235/\text{kW}_t$
Steam Generator	$\$\ 40/\text{kW}_t$
Reformer Plant	$\$\ 75/\text{kW}_t$
Methanator Plant	$\$\ 35/\text{kW}_t$
Storage	$\$\ 40/\text{kW}_t$-day
Pipeline	$\$\ 80/\text{kW}_t$-100 miles
T-G Plant (Base):	
1200 MW_e	$\$270/\text{kW}_e$
800 MW_e	$\$285/\text{kW}_e$
600 MW_e	$\$300/\text{KW}_e$
400 MW_e	$\$320/\text{kW}_e$
200 MW_e	$\$345/\text{kW}_e$
T-G Plant (Peaker):	
150 MW_e	$\$200/\text{kW}_e$
100 MW_e	$\$220/\text{kW}_e$
50 MW_e	$\$250/\text{kW}_e$
Gas Turbine	$\$180/\text{kW}_e$
FBC:	
450 MW_t	$\$\ 80/\text{kW}_t$
300 MW_t	$\$\ 90/\text{kW}_t$
150 MW_t	$\$120/\text{kW}_t$
30 MW_t	$\$235/\text{kW}_t$
15 MW_t	$\$320/\text{kW}_t$
Coal	$\$2.20/10^6$ Btu
Nuclear Fuel	$\$1.20/10^6$ Btu
Distillate	$\$5.70/10^6$ Btu (\$18/bbl oil)
Liquid Fuels from Coal	$\$9.00/10^6$ Btu (∼\$30/bbl oil equivalent)

Table 2-11
HTR-MULTIPLEX FEATURES

Reactor Power	3000 MW_t
Gross Electric Power	160 MW_e
Net TCP Power (Delivered from Methanators)	2470 MW_t
Net Electric Power	Zero
System Capacity Factor	0.80

Table 2-12
DELIVERED HEAT COSTS ($\$/10^6$ Btu)

Capacity Factor--	HTR-Multiplex	FBC			
		15 MW_t	30 MW_t	150 MW_t	300 MW_t
0.90	5.80	4.98	4.35	3.49	3.27
0.60	5.91	6.17	5.22	3.94	3.60
0.30	6.26	9.74	7.84	5.28	4.61
0.15	6.95	16.88	15.00	7.96	7.35

Table 2-13
PRODUCT COST COMPARISON
(1978 Dollars - Levelized Fuel)

Market	HTR-Multiplex	FBC	Oil*	Fluid Fuels From Coal
Dispersed Industrial Heat				
CF = 0.3 $\$/10^6$ Btu	5.90	9.74	6.45	9.75
CF = 0.6 $\$/10^6$ Btu	5.85	6.17	6.20	9.50
CF = 0.9 $\$/10^6$ Btu	5.80	4.98	5.95	9.25
Peaking and Mid-Range Electricity				
CF = 0.15 Mills/kWh_e	101	133	92	129
CF = 0.30 Mills/kWh_e	84	80	79	116
CF = 0.60 Mills/kWh_e	76	60	73	110

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*$\$3/10^6$ Btu

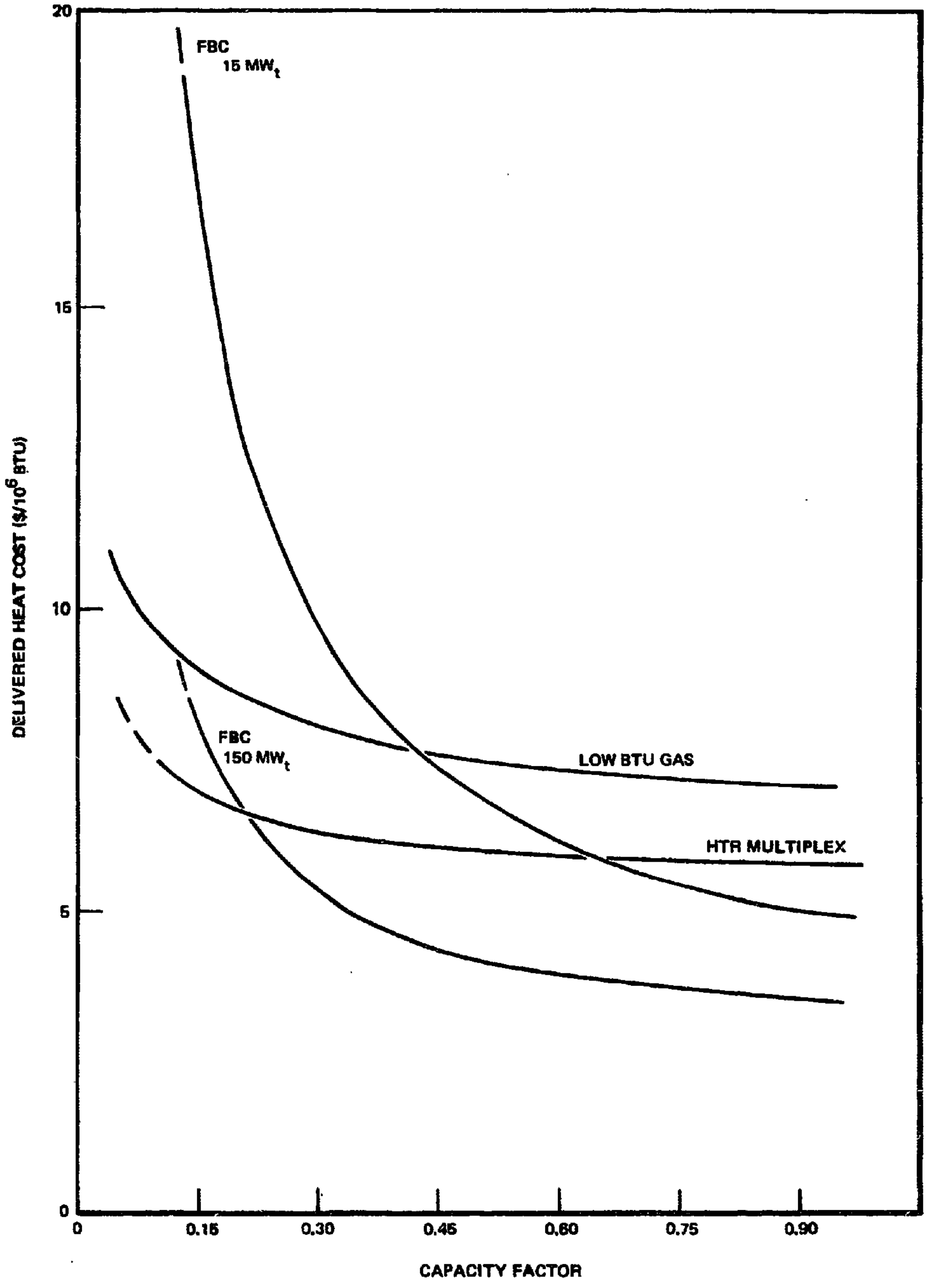

Figure 2-4. DELIVERED HEAT COSTS ($/10^6 BTU)

- For the peaking and mid-range electric market, the FBC costs about 1.30 times the multiplex at a CF of 0.15. The costs are approximately equal at a CF of 0.30.

It should also be noted that the heat cost from the multiplex is almost independent of the user capacity factor or unit size whereas the coal-burning systems are very sensitive to capacity factor and somewhat sensitive to unit size.

In considering future U.S. energy costs, it has been assumed that only two major energy sources would be available: nuclear fission or coal. Previous studies have indicated that an HTR-Multiplex could economically serve the U.S. dispersed industrial heat and peaking-mid-range electric energy markets. These economic studies were based primarily on comparison of the FBC with the HTR-Multiplex. FBCs were chosen for comparison because they appeared to be the most economical way to utilize coal energy in the next few decades.

A more general comparison of the HTR-Multiplex with coal-based energy systems is to consider the spectrum of options for using coal in the markets previously identified. These options consist of:

- Coal-fired TCP systems
- FBCs (or other direct-fired methods if less costly)
- Liquids fuels from coal
- Coal gasification
- -- High Btu (∼950 Btu/SCF)
  -- Medium Btu (∼300 Btu/SCF)
  -- Low Btu (∼150 Btu/SCF)

The coal-fired TCP systems have been rejected because they are beyond the current state-of-the-art; coal-fired reformers present extremely difficult (nearly impossible) development problems. Comparison of the HTR-Multiplex with FBCs, liquid fuels from coal, and High-Btu (methane) gas are summarized in Table 2-14A. The tabulated values are approximate national average costs and regional variations can be as high as 20 percent. Nevertheless, the conclusions appear to confirm that FBCs are the most economical way to utilize coal for the cases considered.

It is estimated that the production cost of Medium-Btu gas is about 80 percent that of High-Btu gas and correspondingly Low-Btu gas is about 70 percent. Low-Btu gas costs more to transport. However, for distances of 100 miles, the transport costs would only add about five percent to the cost of the Low-Btu gas. Thus, preliminary estimates of High-, Medium-, and Low-Btu gas for industrial heat uses (including boiler costs are shown in Table 2-14B.

Table 2-14A
PRODUCT COST
(1978 Dollars - Levelized Fuel)

Market	HTR-Multiplex	FBC	Distillate[±] GT	Oil From Coal	Coal	Methane	Methane From Coal
Industrial Heat and Electricity							
*Peaking and Mid-Range Electricity, CF=0.10 (Mills/kWh_e)	115	136	89	133	--	--	--
*Peaking and Mid-Range Electricity, CF=0.20 (Mills/kWh_e)	86	83	73	107	--	--	--
+Dispersed Industrial Heat, CF=0.3 ($\$/10^6$ Btu)	6.0	9.0	--	10.0	--	--	10.0
+Dispersed Industrial Heat, CF=0.9 ($\$/10^6$ Btu)	6.0	5.0	--	9.0	--	--	9.0
Methane Conversion							
Ammonia ($\$/10^6$ Btu)	8.0	--	--	--	--	7.0	--
Methanol ($\$/10^6$ Btu)	8.0	--	--	--	--	7.0	--
Coal Conversion							
Coal Liquefaction ($\$/10^6$ Btu)	8.0	--	--	--	8.0	--	--
Coal Gasification ($\$/10^6$ Btu)	8.0	--	--	--	8.0	--	--

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* T-G 100 MW_e
\+ 15 MW_t
± \$15/bbl

Table 2-14B
PRODUCT COST
(1978 - Dollars - Levelized Fuel)

Market	HTR-Multiplex	High-Btu Gas	Medium-Btu Gas	Low-Btu Gas
Dispersed Industrial Heat, CF = 0.3 ($/10^6 Btu) (T-G 100 MW$_e$)	6.0	9.0	8.0	7.0
Dispersed Industrial Heat, CF = 0.9 (S/10^6 Btu) (T-G 100 MW$_e$)	6.0	8.0	7.0	6.0

Note that for low capacity factor operation, the Low- and Medium- Btu gas system appear to be superior to FBC systems. However, their costs are still significantly higher than the HTR-Multiplex costs. It should also be noted that the Low-Btu gas system is analogous to the HTR-Multiplex in that a central production plant is assumed that operates at high capacity factor serving a number of dispersed users that operate at low capacity factor through a pipeline-storage system.

In general, the HTR-Multiplex appears to be economically superior to any coal-based system for the dispersed industrial heat and peaking-mid-range electric energy markets. However, both FBC systems and Low-Btu gas systems should be compared more carefully with the HTR-Multiplex for site-specific cases.

In summary, the HTR-Multiplex heat costs shown in Table 2-12 and Figure 2-4 are consistent with previous estimates. Specifically, at unit sizes typical for industrial heat users (15 MWt to 30 MWt), the cost of heat from FBC systems ranges up to 1.5 times the cost of heat from an HTR-Multiplex for one-and two-shift operations. Heat comparisons for peaking and mid-range electricity show similar trends. If oil heat is used, then the cost of fuel alone at \$3/10^6 Btu (\$18 per barrel) is greater than the cost of HTR-Multiplex heat for all sizes and capacity factors.

2.2.2.5 Additional Considerations

The one basic component of the HTR-Multiplex is the HTR itself, and even its design and configuration remain to be defined. The other energy system components chosen to be co-located with the HTR will affect the HTR configuration and be affected by it. A set of optional HTR configurations may prove desirable; conversely, the benefits of standardization may dictate that a basic configuration be chosen.

Various chemical reactions can be driven by heat from HTR-Multiplex. The steam-methane reactions and thermo-chemical pipe are of most interest because they appear broadly applicable to produce industrial steam and draw largely upon well-known technology. Other reactions, perhaps supplementing rather than replacing the steam-methane reactions, should be evaluated.

Hydrogasification of coal at the HTR-Multiplex is a chemical reaction of interest. Methane produced from coal could become the feedstock for the reformer plant, and permit one-way single-pipeline operation of a TCP system, and furnish methane at the methanator output for clean combustion or chemical feedstock - an open-loop TCP.

Another example is thermochemical water-splitting. Hydrogen and oxygen are valuable chemicals widely used in industrial processes. If piped to industrial sites and available at attractive prices, they would be used even more widely. Piped to thermal-electric plants, hydrogen and oxygen could be recombined in a combustion process that is absolutely nonpolluting: only steam would be produced, to drive a turbine whose exhaust could be condensed to supply heat to hot water used in district-heating networks. Energy efficiency would be outstanding.

Innumerable industrial processes requiring heat in the 590-930°F range might be considered for location at an HTR-Multiplex. However, until enough experience and public acceptance have been gained from simpler HTR-Multiplex configurations, postulating colocation of industry at the HTR-Multiplex does not appear realistic.

In connection with chemical plant operations and baseload generation of electricity at the HTR-Multiplex there will be a substantial amount of reject heat. This heat will either be expensively wasted by discharging it through cooling towers or into water bodies, or utilized for district heating.

Pipelines encounter their share of objections when rights-of-way are to be obtained, but pipelines at least are unobstrusive when completed. One of the merits of the HTR-Multiplex concept is its employment of pipelines to transport a substantial fraction of its energy products. Suggestions have been made which would concentrate thermal power generation capacity into a few geographical locations, rather than permitting construction of plants as close to load centers as possible. The use of pipelines could be a particularly important factor in minimizing the width of transmission corridors in this situation.

Properly optimized, HTR-Multiplexes provide a more efficient use of energy resources than either LWR's or fossil-fired electric plants.

The industrial process heat needs that can be met with steam (and, perhaps, methane) from the TCP system would otherwise be met by burning fossil fuels. Steam produced from a methanator, with no combustion, causes no air pollution. If replacing fossil-fired heat sources, the result will be reduced air pollution. If satisfying new requirements, emission offset requirements will be avoided - quite possibly making the difference between being able to construct new industrial plants and not being able to do so.

Components of the HTR-Multiplex downstream of the reformer are all commercially available with the exception of the high temperature methanator and it has gone through pilot plant operation. The HTR itself appears to be ready for demonstration or lead plant construction for helium outlet temperatures of 950°C.

The major technical concern is the helium-heated reformer. Commercial reformers operate at the temperatures needed but are not designed for 30-year life nor to operate with carbon content environment typical of HTR-helium.

In addition to the reformer there are a variety of other concerns that need assessment. Some examples are:

- Market assessment of user requirements and geographical density.
- Institutional problems, if any, relating to implementation.
- Regulatory problems, if any, relating to CO and H_2 pipeline operation.

- Tritium contamination of the TCP system, and potential fission product contamination if large leaks occur in the Reformer (Helium-to-Process).

2.3 REFORMER INDUSTRY MARKETS

Ammonia and methanol are the primary products of those 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% 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% 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.

2.3.1.1 Ammonia

Consumption of ammonia is keyed to its role in agriculture; about 75% of U.S. production goes to fertilizer uses, as shown by its overall use pattern.(2-6)

	Percent
Fertilizers and Animal Feeds	75
Fiber and Plastic Intermediates	9
Explosives	5
Paper and Rubber Products	2
Other (Refrigerants, Cleaners, Losses, Etc.)	9
	100

2.3.1.1.1 Demand

Total domestic demand for ammonia is presently about 17 million tons per year. The recent domestic production statistics and derived projections are shown in Figure 2-5. The data indicate an annual domestic production growth rate of 11.6% from 1950 to 1966, followed by a marked decrease to 3.3% 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% rate results in the range shown by the shaded area. The upper limit of the uncertainty range represents annual growth at 5.1%; the lower limit, at 1.5%. 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% 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(2-7). 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 This page for Figure 2-5 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 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(2-8). 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% utilization. The World Bank estimates that additional global capacity

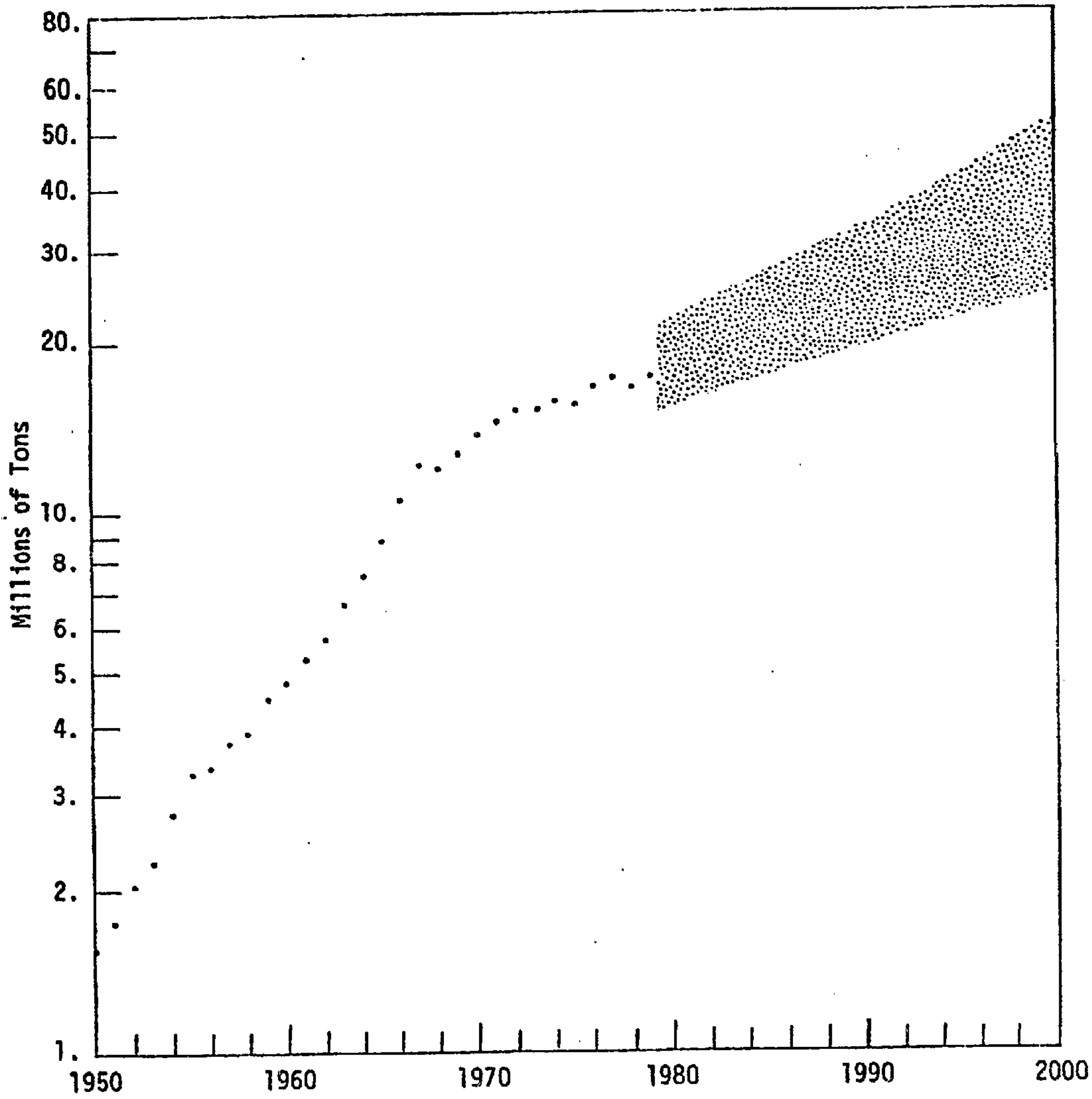

Figure 2-5. AMMONIA PRODUCTION, 1950-1978, AND PROJECTED DOMESTIC DEMAND

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.

2.3.1.1.2 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% 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(2-9) that real growth in domestic demand will average 3% 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 diffucult to conclude that the Soviets will want to keep prices down. There is additional potential for ammonia productrion 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.

2.3.1.1.3 Alternative Technologies

Historically, ammonia has been obtained in a variety of ways: as a byproduct in coke production, from byproduct hydrogen (petroleum refinery, chlor-alkali 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% of U.S. capacity and 75-80% 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 naptha fraction. Operation of a naptha fed and fired reformer furnace differs little from its natural gas counterpart(2-10).

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.(2-11) 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/MMBtu) and coal at $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 from 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(2-11).

2.3.1.2 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% of which is consumed in the chemical industry as shown by the following use pattern:(2-6)

	Percent
Formaldehyde (for phenolic resins and plastgics)	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
Solvents	10
Miscellaneous (denaturant, anti-freeze, anti-knock agent, etc., exports)	15
	100

2.3.1.1 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 2-6. From 1954 to 1974, demand grew at 9.5% 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 (1975/75) 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 2-6. 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.

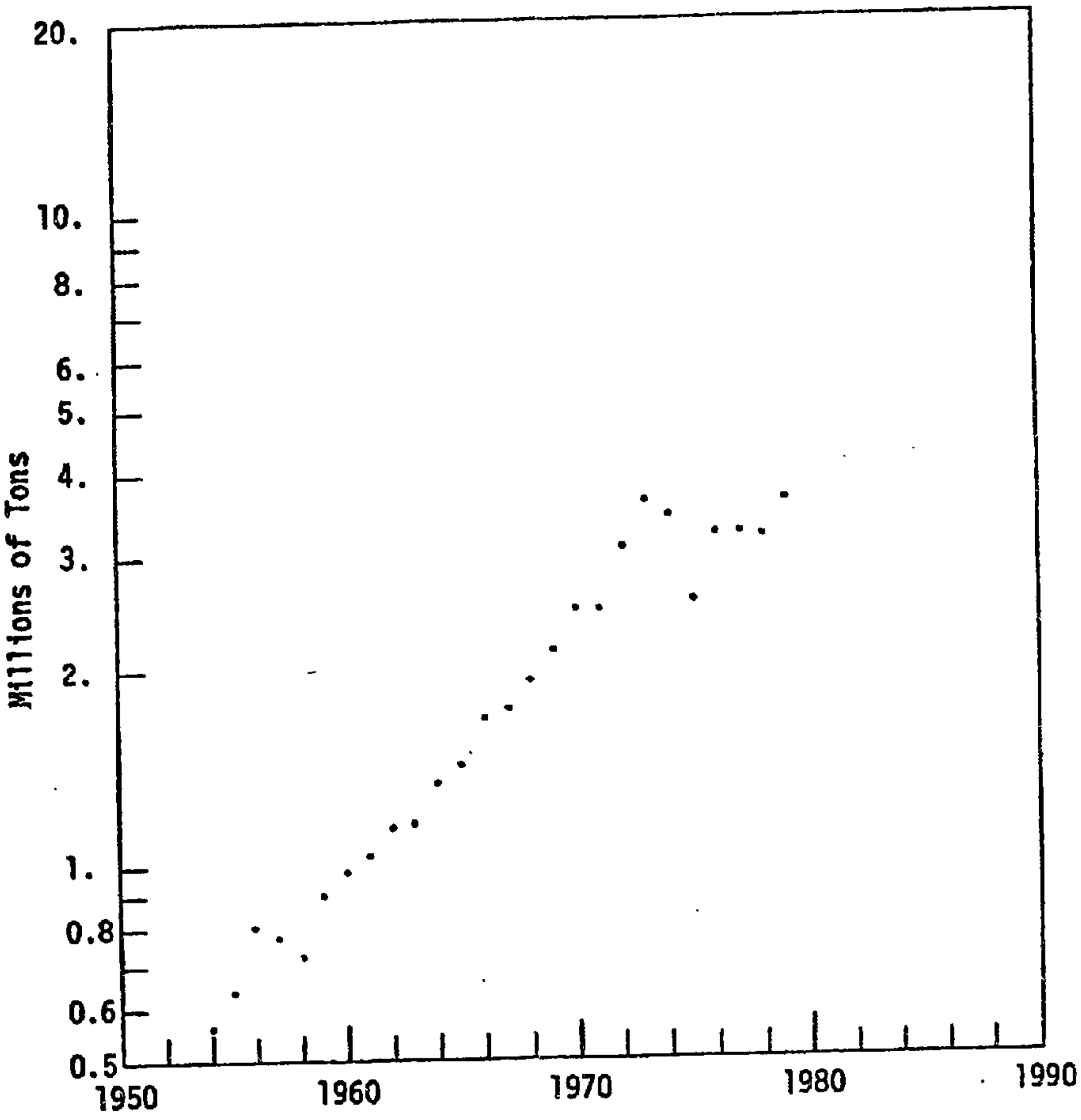

Figure 2-6. METHANOL PRODUCTION, 1954-1978

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. 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.

2.3.1.2.2 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 facts is that the methanol supply picture is virtually the same as that for ammonia, and in particular 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.* 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.

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*Chemical and Engineering News, March 6, 1979.

2.3.1.2.3 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 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 per ton) based on coal at $25 per ton. 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 suport a price of 30-32 cents a gallon in the first years of operation(2-12). To achieve this low a production cost via natural gas reforming would require a gas price of $1.50 per million Btu (non-levelized).

2.3.1.3 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 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 fluctua tions 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 hydrogen is from steam reforming. Then the almost 90 billion cubic foot production level of 1977 would have required less than 4% 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. Only 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% per year.* 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).

2.3.1.4 Competitive Market Assessment - Ammonia, Methanol, and Hydrogen

The previous secton 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 andcoal-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. Of this, the fraction of natural gas burned

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*Chemical and Engineering News, May 15, 1978.

as fuel is a little higher for ammonia (38%) than for methanol (28%, assuming carbon dioxide feed available). Approximately, then, the HTR-heated system concept displaces the fuel fraction or 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% 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.

2.4 COAL CONVERSION MARKETS

2.4.1 Concepts

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 the 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 generating 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.

2.4.2 Market Environment

2.4.2.1 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% 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(2-13). 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 2-15.

Table 2-15
UNITED STATES COAL PRODUCTION FORECASTS
(Millions Of Short Tons Per Year)

Source	Date Of Forecast	1985	1990	2000
Project Independence	1974	1,100	1,300	
Project Interdependence	1977	940	1,225	
National Energy Plan	1977	1,050	1,250	
Department of Commerce	1977	890		1,860
National Research Council	1977	995	1,250	1,700
Department of Energy	1978	1,112	1,520	

Source: Hayes, 1979; *Oil and Gas Journal*, March 26, 1979.

Perspective on utilization of the coal resource is provided by the Department of Energy's medium level consumption forecast, Table 2-16. The overall growth rate of 6.5% per year encompasses rapid penetration by coal into the industrial sector, presumably displacing oil and gas, and phenomenal growth of the synthetic fuels industry.

Table 2-16
UNITED STATES MARKET FORECAST FOR COAL: MEDIUM CONSUMPTION SCENARIO
(Millions Of Short Tons Per Year)

	1977	1985	1990	Average Growth Rate (Percent Per Year)
Electric Utility	475	760	1,007	6.0
Industrial	60	159	279	12.6
Metallurgical	77	96	100	2.0
Synthetic Fuel	--	22	56	20.0**
Other*	61	75	78	2.0
TOTAL	673	1,112	1,520	6.5

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*Includes residential and commercial use and exports.
**Over 1985-1990 period.

Source: U.S. Department of Energy

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2.4.2.2 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. Details of coal refining technology are provided in Section 5.0.

2.4.2.3 Competitive Market Assessment

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% is assumed, then the 56 million ton per year rate of coal consumption for synfuels in 1990 (Table 2-16) would create a market for 13 GWt 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% per year of Table 2-16 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 GWt 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(2-14) 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. Thus, there is not 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.

In the light of these issues, it is believed that despite their 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.

2.5 NUCLEAR PROCESS HEAT INDUSTRY EVALUATION

A continuing effort is underway to obtain the reaction, critical commentary and potential participatory interest of those segments of industry who could be future suppliers and/or users of nuclear generated process heat. Herein is a summary of our findings to date of this survey.

2.5.1 Survey Objective

The survey objectives are to stimulate industry response in the following areas:

- The perceived need for high temperature nuclear process heat.
- The soundness of the preliminary conclusions reached concerning areas of application chosen for high temperature nuclear process heat.
- Recommendations of further industry contact whose input and possible participation can enhance the value of the on-going HTR market assessment.
- The bases upon which industry would participate in future development of high temperature nuclear process heat.
- The willingness of those indicating positive interest to support the further development of the HTR-Multiplex concept in Congress.

2.5.2 Industries Surveyed

This survey is ongoing and will continue and as part of periodic market assessment updates. Initial contacts have been selected who:

- Have a potential need for a high temperature reactor-process heat supply.
- Are or have participated in coal conversion projects.
- Have a broad knowledge of the energy generation and supply industry.

To date the following companies or associations have been contacted.

Survey Participants to Date

Utilities:
PG&E, San Francisco, California
Southern Services, Birmingham, Alabama

Oil Companies:
AMOCO, Naperville, Illinois
Ashland Oil Company, Ashland, Kentucky
Exxon Research & Engineering Company, New Jersey
The Oil Shale Company
Universal Oil Products

Gas Transmission Companies
MAPCO
Texas Eastern Gas Transmission Company

Architect Engineers
C. F. Braun, Alhambra, California
Burns & Roe
Fluor, Irvine, California
Stone & Webster, Los Angeles

Institutional Organizations
American Gas Association, Washington, D.C.
Electric Power Research Institute, Palo Alto, California
Gas Research Institute, Chicago, Illinois
Institute of Gas Technology, Chicago, Illinois
National Coal Association, Washington, D.C.

2.5.3 Industry Comments

Presentation Format and Industry Response

The material reviewed with industry contacts can be summarized as:

A. Program Objectives

B. HTR-Multiplex Market Assessment

C. Technical Summary of the U.S. and FRG HTR Programs

D. Process Heat Applicatons with the HTR

   Thermo-Chemical Pipeline
   Coal Conversion
   Chemical Production

E. Informal, Round Table Discussions

2.5.3.1 In summary, interest exists in alternate forms of process heat for fossil fuel conservation and conversion, but active support depends upon the degree and aggressiveness with which the DOE sponsors the initial stages of development of HTR process heat concepts. This posture is due in large part to: (1) the very near term goals of fossil energy supplies and users oriented to the development of commercial energy resources over the next 5 to 10 years, and (2) the assumption that longer range energy resource development, with commercialization not occurring until the 2000-2020 period, should initially be stimulated by the Federal Government with its greater resource capabilities for such long range projects of potential national need.

The following are major areas of commentary:

o The concept of the HTR-Multiplex must be demonstrated by identifying a site specific need and by operating a test (prototype) plant. There will be difficulty in establishing owner and user support because of lack of precedent for this system and the diverse nature of potential industrial process heat users. Workable solutions to the political, institutional and regulatory issues must be found before industrial participants would be willing to assume a significant financial part in the initial deployment of an HTR-Multiplex System.

o Concepts of the HTR-Multiplex for coal conversion still must be identified that have a real economic advantage over comparable fossil fired coal conversion processes. Existing conversion process systems appear to have only a fossil resource conservation incentive and no economic or technical incentives to utilize nuclear process heat over existing conventional energy sources.

- When considering coal conversion, it appears that the HTR-Multiplex rating should be in the 1000 MW_t range to match coal mine outputs. However, a recent NCA report indicated that possible outputs of several (about 20) new western mines (approximately 1985) may match a 3000 MW_{th} HTR rating. (Projected 220 x 10^6 T/year from the whole state of Wyoming could support about 10 x 3000 MW_t HTRs for coal conversion.)

- A consensus of those surveyed believed that coal conversion to gas and/or liquid would be economic by 1985.

- Several industrial contacts are interested in the concept of participating in DOE-sponsored programs to further define and develop specific areas of the HTR as a process heat source.

- A willingness exists to support in the Congress the further development of nuclear process heat concepts which are a part of a well-defined and organized program structure.

2.5.3.2 During the survey, concerns both of technical and institutional natures were identified which will require resolution as nuclear process heat proceeds in development, these were:

- Regrowing public fear of nuclear power and the light water reactor.

- The potential of radioactivity in syngas pipelines (Primary System/Reformer Gas Leaks).

- The toxicity potential of CO to end-users of syngas.

- The safeness of transporting H_2-CO in pipelines to end-users and the assignment of liability responsbility for such systems.

- The difficulty of initiating the system which will provide a Thermochemical Pipeline grid.
- The issues of ownership and operation of the HTR-Multiplex and the related Public Utility Commission regulatory impacts.

Initially it appears that nuclear process heat user support will rank as follows:

a) Institutional organizations

b) Oil companies

c) Gas and oil transmission companies

d) Selected utilities

e) Large coal companies

2.5.4 Future Industrial Participation

A key objective of the survey has been to identify, from the supplier/user viewpoint, those areas of near term endeavor which would be of greatest value in determining the direction HTR technology should take in applying economically competitive high temperature nuclear process heat to a user market.

An initial listing of these areas is given below:

1979

- Institute of Gas Technology
  ($10K; complete Aug. 30)

  Consultation and review on GE coal conversion and thermochemical pipeline work.

  - Study of water-splitting and chemicals production applications for HTR-Multiplex.

- UOP, Inc.
  ($5-10K; complete September 30)
  - An application of HTR-Multiplex to refinery for upgrading coal liquids to motor fuels.

1980

1. Assessment of thermochemical pipeline application in Gulf Coast Area or another equally rated area..
2. Assessment of site specific test reacto/thermochemical pipeline application.
3. Application of HTR to catalytic gasification process.
4. Application of HTR-Multiplex to oil shale processing.
5. Assessment of HTR-Multiplex application to SASOL plant (using Lurgi or other gasifier.
6. Assessment of HTR-Multiplex application to coal liquids refinery.
7. Continuing development and testing of steam reformer components.

1980 User Participation

Formation of a user advisory group (oil, gas, pipeline companies).

NUCLEAR PROCESS HEAT
INDUSTRY ASSESSMENT

	Overall Response	Interest In Cooperative Support	Provide Congressional Support	TCP	Coal Conversion	Chemicals	Comments
Utilities	Cool to enthusiastic	If properly organized consultation	Non-commital and yes, if properly organized	Long range, potential looks promising. But first become site specific in your analysis.	Don't integrate to today's technology - too primitive. Look to future process developments, factoring HTR-Multiplex in now. Meanwhile, make hydrogen! Don't try to push large plants.	Focus on R&D programs which will make cheap hydrogen.	General consensus 1. Optimum plant size definitely less than 3000 MW 2. Resolve fuel cycle dilemmas 3. Develop and sell a technical "fix" of low level radiation to convince the public of reactor safety
Architect Engineers	Good interest in pursuing further	yes, subcontractor	yes				
Oil Companies	Good interest but wait and see	Yes (consultative	If program continues to look strong technically, then yes				
Gas Pipeline Cos.	Non-commital	Evaluating material	Non-commital				
Chemical Cos.	No sample	No sample	No sample				
Industrial Associations	Cool to enthusiastic	Yes, consultative to subcontractor	Yes				

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SECTION 3

ENVIRONMENTAL, REGULATORY AND INSTITUTIONAL ASSESSMENT

3.1 ENVIRONMENTAL ANALYSIS

This section addresses the environmental effects of the use of a TCP system to produce industrial process heat. Three separate but interrelated analyses are performed. First, the possible environmental impacts produced by the steam reforming, gas transport, and methanation will be evaluated; this evaluation briefly summarizes the environmental effects produced by the HTR heat source emphasizing those effects which might induce unique environmental problems on the TCP system (a complete analysis of HTR impacts is beyond the scope of this study). Second, the net environmental effects at the point of process heat use produced by substituting TCP for other methods of generating process heat are calculated. Coal, residual oil, and natural gas are the fuels assumed to be substituted by the TCP. Finally, a comparison is made of the total environmental effects from process heat generated by coal, residual oil, and the HTR-Multiplex. This total effects comparison considers the impacts of fuel mining, processing, transportation, and waste disposal as well as heat generation.

For the comparisons the basic unit of impact is the environmental residual which is defined as the product of an activity or process which is produced in addition to the primary product. The implicity assumption is that the environmental impact of a process is proportional to the residuals produced. No attempt is made to value the residuals, e.g., make a comparison of acres of land used against tons of waste produced on some common scale, although there are methods for such comparison. Using the broad definition, residuals include such effects as solid wastes, air and water pollution, and radioactivity.

The impacts, or residuals, are expressed in terms of units per 1000 MWt over a stated time period. For the TCP the reactor heat source is located 200 miles from the point of use. At that point, end use is through units producing 100 MWt each. The reference TCP system is closed, i.e., a mixture of carbon dioxide, carbon monoxide, methane, and hydrogen is piped from the reformer to the methanator, and a different mixture of the same gases plus water is returned to the reformer. The analyses are goegraphically independent; however, for comparisons, the effluent from Illinois coal is used.

The values reproduced here are from five main sources:

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3.1.1 HTR-Multiplex Impacts

The basic components of the system are the heat source, steam reformer and methanator, and gas transport.

3.1.1.1 Heat Source

A reactor is required to produce the heat necessary to drive the endothermic reaction at the reformer. The reference reactor is a pebble bed HTR operating on the thorium cycle using helium as the coolant and graphite as a moderator. Uranium enriched in U-235 is the fissile material in the initial core and makeup fuel elements. U-233, bred in the thorium, is the fissile material which can be recovered and reused. Fissile uranium may be either of a low or of a high degree of enrichment. Thus, the residuals from the enrichment process will be dependent on the final reactor design.* In both fuel enrichment cycles approximately one-fourth of the fuel is replaced each year.

While this report is not intended to compare HTRs and LWRs, a comparison of the environmental effects of the two reactor systems is included here to provide perspective on the HTR.

The environmental residuals of LWRs are well-documented. There are six areas where major differences in residuals exist between the thorium cycle HTR and the uranium cycle LWR:

1. Although the physical residuals from mining, milling, and processing thorium and uranium fuels are similar, the total radioactive waste from the uranium fuel is about 25 times greater than that from thorium fuel, i.e., 20 curies per 1000 MWt versus about 500 Ci for the LWR. In underground mining, however, the thorium produces the greater potential impact. The thorium decay chain yields Rn-220 which, in an underground mine, has less chance to escape than the longer-lived Rn-222 from uranium decay. The underground mining of thorium would be expected to result in slightly increased risks of respiratory cancer for miners, however it is not clear what percentage of thorium will be mined underground.

2. The capacity to heat helium to high temperatures at high pressures allows the HTR to achieve higher efficiencies than the LWR. Because of this higher efficiency, the HTR produces about 25% less fission products for a given electrical power output. This results in a lower radioactivity inventory per unit of electrical output.

3. The higher efficiency results in roughly 25% less waste heat then the LWR produces for a given electrical power output. The thermal load delivered to the environment from that portion of the reactor power

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*The major difference is the greater amount of electrical energy required for the highly enriched fuel. The annual uranium requirements for the HTR are lower than those for the LWR so the separation work at the enrichment plant is slightly less for the HTR.

directed toward producing at-site electricity is consequently lowered. The decreased waste heat also reduces plant water consumption.

4. The emissions of gaseous radioactivity of an HTR can be an order of magnitude lower than those of an LWR, particularly for the bioaccumulatable isotopes of strontium, cesium and iodine.

5. The production and release of C-14 is of great biological significance because of its 5700-year half life and the importance of carbon on photosynthesis and the possibility of its incorporation into man's food chain. The HTR generates about 7 to 10 times as much C-14 as does the LWR. However, the C-14 activation product is integrally bound within the graphite fuel elements and can only be released during reprocessing or waste disposal operations.* During reprocessing the graphite on the fuel pebbles is oxidized to CO_2 in a fluidized bed burner. The carbon, enriched in C-14, is recovered for disposal as a carbonate. Disposal is along with other low activity wastes in shallow landfill. The C-14 containing carbonate is water soluble, allowing the C-14 to enter the biosphere. If the waste were to be handled as high-activity waste, the potential problem would be ameliorated.

6. It is frequently claimed that intrinsic design features of the HTR may enable a given level of safety to be achieved at a lower cost.

   - The graphite core can absorb large amounts of heat; thus a loss-of-coolant accident would result in a slow raise in core temperature, reduces the reliability of release of fission products and provides 10 to 20 hours for decisions and action to be taken before excessive core temperatures are reached.

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*In a LWR about 8 Ci/1000 MWt are released per year at the reactor and about 15 Ci during reprocessing.

- All major reactor components, including the TCP steam reformer, may be located within the prestressed concrete reactor vessel. Therefore, the possibility of rupture of, say, a primary cooling pipe outside the reactor vessel may be eliminated.
- The use of small, coated fuel particles may reduce the amount of fission products released into the coolant.

In summary, the HTR operating on the thorium cycle results in some greater and some lesser environmental impacts than does an LWR operating on the uranium cycle; the important comparison, however, is one involving the HTR-Multiplex against conventional heat sources. This is done below.

3.1.1.2 Heat Conversion

Heat-to-gas-to-heat conversions are accomplished by reactions in the steam reformer at the reactor and the methanator at the point of use. These equipments are common in refineries and chemical complexes and are environmentally benign. No waste products are produced by the reactions. A monolithic catalyst, probably nickel, is required. The catalyst is non-toxic and non-hazardous.

The HTR affects normal heat conversions in two ways. First, the use of graphite in the core introduces a possible steam-carbon reaction. If large amounts of steam enter the core via rupture in the heat exchanger, the reaction would result in structural damage and rupture of the fuel particles with a consequent release of fission products. Second, tritium is produced by neutron activation of impurities in the reactor. It has been estimated that about 0.5% of this tritium will diffuse into the coolant gas.(3-1) At elevated temperatures tritium can diffuse through the metal wall of the heat exchanger and enter the steam reformer where it has the potential to be introduced into the entire transport system. The diffusion is inhibited by an oxide coating on the heat exchanger so may be easily controlled. In an analysis of the use of a 3000 MWt HTR and steam reformer to produce hydrogen for addition to natural gas lines, it was determined that if 50% of the gas burned in a home were reformer-produced hydrogen, the individual radiation dose would be about one-tenth of the allowable standard. A more feasible mix of about 15% hydrogen, which could be burned with current gas equipment, would result in a lower radiation dose.

p p

The probabilities of both of these possibly deleterious effects will require further evaluation.

3.1.1.3 Gas Transmission

Three high-pressure gas transmission pipes are required for a closed cycle 1000 MWt TCP; a 1.2 m-diameter pipe connecting the reformer and methanator containing primarily carbon monoxide and hydrogen; a 0.75 m-diameter pipe to return methane to the reactor, and a 0.25 m-diameter pipe for return water. Since the gas is at near-ambient temperature (unlike steam transport systems), the pipe can be uninsulated and laid underground. The pipes will have residuals similar to those of high pressure natural gas transmission lines. The pipes will be buried two to four feet below the surface in a cross country right-of-way. About 8 acres will be required for each mile of transport; however, other beneficial uses (e.g., farming), are usually made of pipeline right-of-way.

Line pressure drops about 3 psi per mile. Pressure will be maintained by compressors located at 50- to 100-mile intervals. These compressors will probably be driven by electric motors. Sectionalizing valves will be located at various intervals to isolate pipe sections if a rapid large-pressure drop occurs.

The residuals from construction are minimal if care is taken to minimize erosion. Operations include clearing and grading of right-of-way pipe stringing, welding the strung pipe, ditching, coating the pipe, lowering pipe, and backfilling the ditch. The final step restores the land to near its former condition.

The gases carried by the pipes are highly flammable. In addition, carbon monoxide is toxic. Table 3-1 lists safety parameters of the gases.

Table 3.1
POTENTIAL HAZARDS OF TCP GASES[a]

	Hydrogen	Carbon Monoxide	Methane
Toxic Hazard Rating	None	None	None
Acute Local			
Acute systemic-inhalation	Slight	High	Slight
Chronic Local	None	None	None
Chronic Systemic-inhalation	None	Slight	Slight
Fire Hazard	Highly Dangerous	Dangerous	Dangerous
Explosion Hazard	Severe	Severe	Dangerous
Explosive Range	4.1-74.2%	12.5-74.2%	5.3-14.0%
Maximum Allowable Work-Room Concentration		50 ppm (55 mg/m3 air)	

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[a] Data from N.I. Sax, Dangerous Properties of Industrial Materials, Reinhold, New York 1968

If a pipe rupture should occur (assuming a sectionalizing valve each 20 miles*) in the CO-H_2 pipe, a potentially explosive hemisphere about 400m in diameter could be formed. A break in the methane pipe could produce an explosive source 304m in diameter.

Both CO and methane are asphixiants. CO is colorless and odorless and has an affinity for hemoglobin about 210 times that of oxygen. By combining with hemoglobin CO renders it incapable of carrying O_2 to tissues. Methane is a simple asphixiant, acting by diluting oxygen in air. Table 3-2 indicates the effects of CO at various concentrations. If a pipeline break occurs, an area with a diameter of 690m could have an initial concentration greater than the lethal 4000 ppm. This area could be reduced if sectionalizing valves are located at intervals less than 20 miles used for this analysis. The diffusion of the CO would be controlled by local meteorology.

3.1.2 Point-of-Use Impacts

Heat is produced by the exothermic chemical reaction at the methanator. The TCP heat can substitute for a variety of processes now used to produce industrial heat. A key issue is a comparison of the residuals produced by the TCP at the point-of-use with the residuals produced by the conventional heat sources.

Since the reference TCP uses a closed cycle, the only environmental residual is the land area required for the methanator, assumed to be 1 acre/1000 MWt.** Table 3-3 shows the residuals produced by the TCP and by the fuels likely to be displaced by TCP. In the time frame of projected development, coal will be the major fuel displaced. It is immediately apparent that substitution will result in substantial lowering of the air pollution emissions. The consequences of this lowering are discussed in Section 7. Coal gasification or solvent refining would

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*Sectionalizing block valves are required every 20 miles for Class 1 locations (sparsely populated grazing land, farm land, and wasteland). More populated areas require block valves at shorter distances.

**Varying amounts of waste heat are produced by the different process which uses the TCP heat. These are ignored in this analysis. The occupational accidents produced by the TCP cannot be estimated at this time.

Table 3.2

CARBON MONOXIDE EFFECTS.[a]

(NATIONAL AMBIENT AIR QUALITY: 35 ppm FOR 1 HOUR EXPOSURE
9 ppm FOR 8 HOUR EXPOSURE)

Concentration ppm	Exposure Time	Effects
Acute Effects		
50	2 hours	Shortened average time to a heart attack among individuals with heart disease[b].
53	1.5 hours	Shortened average time to a heart attack among individuals with heart disease.
100	0.5 to 2 hours	Loss of physical and mental coordination among healthy subjects.
500	1 hour	Mild to throbbing headache among healthy subjects[c].
1,000	Less than 1 hour	Vomiting, unconsciousness and death among healthy subjects.
4,000	--	Lethal

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a. Adapted from Leung, Goldstein, and Dalkey, "Final Report: Human Health Damages from Mobile Source Air Pollution, 1975", California Air Resources Board, cited in Methods Developedfor Assessing Air Pollution Control Benefits, EPA-600/6-79-0016, February 1979.

b. Arnow, W.S., and N.W. Isbell, "Carbon Monoxide Effect on Exercise-Induced Angina Pectoris', Annals of Internal Medicine, 79 (1973), 392-395.

c. Koch-Weser, J., "Common Poisons", in Harrison (ed) Principles of Internal Medicine, Ch. 166 (1970), 652-653.

also result in lowered SO_2 emissions (at the point of use) and efficient burning technology can reduce NO_x emissions; however, the advantage of the TCP would remain. This advantage is especially apparent for carbon dioxide, an effluent not presently regulated, but one which might ultimately limit the use of fossil fuels.*

The fact that TCP does not produce carbon dioxide in appreciable quantities at any point in its fuel cycle will form a pervasive argument for its use as controversy over CO_2 develops.

3.1.3 Fuel Cycle Impacts

Table 3-3 shows the point-of-use impact; however, for meaningful comparison of the various process heat alternatives, the residuals for the total fuel cycle must be determined. This total will include residuals from mining, processing or conversion, reprocessing, if necessary, transportation, and waste disposal as well as the residuals associated with use of the fuel.

Table 3-4 summarizes the most important of these total residuals for residual oil, coal, and HTR-Multiplex based on a thorium fuel cycle. The "Land Required" category includes the area required for coal cleaning, fuel processing, etc.,as well as that required for fuel storage and heat generation. The annual increment is the surface area disturbed per year by mining. "Resources Used" refers to the total energy and water requirements to mine, process and transport the fuel and to transport and dispose of the waste. The health impacts of the gaseous and radioactive effluents were not calculated since these impacts are highly site-dependent. However, various studies** indicate that the "Social Costs", which include soiling costs and changes to property value as well as health costs, for coal and uranium fuel cycles are comparable (assuming complete SO_2 scrubbing for the coal cycle). The uranium and thorium fuel cycles have much in common, so the impacts should be similar.

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*Numerous scientists have forecast grave problems if the CO_2 content of the atmosphere continue to rise. The most recent warning was voiced in Science, 205:276-377, July 1979, where G. F. J. MacDonald G. Woodwell, and C. Keeling were reported to have presented to the President's Council on Environmental Quality a warning about an accelerated program of synfuel development and use of fossil fuel generally.

**A recent example is Bernardi, R., and B. Burko, Quantitative Environmental Comparison of Coal and Nuclear Generation: Workshop Summary, Mitre Corporation, MTR-7004, September 1975.

Table 3-3. Comparison of the environmental effects of the process heat sources likely to be displaced by an HTR-Multiplex. Pollutants per 1000 MW_t at the point of use.

	Natural Gas	Residual Oil	Coal	TCP
Present Use for Process Heat (percent)	43	22	35	
Projected Future Use	sharply down	down	up	
Resources Used (per day)				
Fuel	67.4×10^6 cf(a)	9700 bbl(b)	2700 T(c)	N.A.
Process Water (gal)	3300	3300	10,500	--
FGD Scrubber Water (gal)(d,e)	--	--	475	--
Limestone (tons)	--	--	400	--
Land Required (acres)				
Plant and Fuel Storage(d)	--	--	53.7	1
Waste Storage(d)	--	--	20	--
Emissions (tons/day)				
Particulates	0.45	0.16	2.3	--
SO_x	0.02	22.10	34.2	--
NO_x	6.11	9.18	28.5	--
CO	0.01	7.90	1.05	--
CO_2	4425	4742	6300	--
Hydrocarbons	1.16	0.98	281	--
Aldehydes	0.09	0.20	--	--
Organics	--	--	0.003	--
Heavy Metals	--	4.11	0.2	--
Radioactivity (m Ci/day)	--	0.55	3.67	?(f)
Solid Wastes (tons/day				
Bottom Ash	--	1.48	59.3	--
FGD Scrubber Sludge	--	--	816	--
Fly Ash Retained	--	--	235	--
Occupational Accidents (per year)				
Fatalities	0.1	0.1	0.1	?
Injuries	0.6	0.6	0.5	?
Man Day Lost to Accident	135	135	135	?

Notes:
(a) Based on 1000 Btu/cf.
(b) Based on 6.3×10^6 Btu/bbl.
(c) Based on Illinois #5 coal; 11,400 Btu/lb, 2.5% sulfur, 10% ash.
(d) Assume the total of 10 separate 100 MW_t units.
(e) Assume full scrubbing of all coal-fired boilers > 15 MW_t.
(f) Assumed to be very low.

Table 3-4. Comparison of alternative process heat sources. Total annual environmental effects due to the complete fuel cycle for a 1000 MW_t. Includes mining, processing, transport, conversion, reprocessing, and waste disposal.

	Residual Fuel Oil	Coal	HTR-Multiplex
Land			
Temporarily Committed (acres)	630	8800	390
Annual Use	70	291	4.7
Occupational Accidents Per Year			
Fatalities	0.06	0.43	0.04
Injuries	5.04	18.43	2.56
Man Days Lost	679	3640	374
Resources Used (excluding process fuel)			
Process Heat (billion kW_t/yr)	6.9	6.9	8.43
Electrical Energy (million kW_e/yr)	26.4	39.4	106.3
Process Water (million gal/yr)	690	570	36
Other Water(a) (million gal/yr)	3900	6643	--
Effluents			
Particulates (T/yr)	10,200	106,300	3150
SO_x (T/yr)	15,200	47,200	1400
NO_x (T/yr)	10,240	10,600	320
CO_2 (T/yr)	1.8×10^6	2.2×10^6	36
Radioactivity to Atmosphere (Ci)	2×10^{-4}	1.34	160(b)
Tritium	--	--	--(d)
^{85}Kr	--	--	--(c)
Radioactivity to Water (Ci)	--	--	135
Solid Wastes (T/yr)	86.9	39(c)	70

Notes: (a) Required to dilute liquid wastes to acceptable standards.
(b) Excluding ^3H and ^{85}Kr.
(c) Excludes mine spoil and beneficiation.

(d) Negligible impact based on current ORNL FG release specifications for fuel reprocessing cycles under development. If ^3H and ^{85}Kr were allowed to escape to the environment their impacts would be ^3H-6153 Ci and ^{85}Kr - 2.9, 230/1000 MW_t/yr.

3.1.4 Summary

The TCP system, when operating as designed, is environmentally benign, however additional analyses are needed to assess the hazard of accidents. When comparison is made of TCP heat substituted for other fuels at the point of use, estimates show environmental impact is lessened. If the entire fuel cycle is considered the HTR-Multiplex system produces less total environmental residuals than do systems based on burning coal or residual fuel oil.

3.2 AIR QUALITY REGULATIONS

The Clean Air Act and its amendments, and the regulations promulgated by EPA, the States, and air quality control regions, have tremendous impact on industry. Substantial mitigation of this impact and improvement in air quality are possible through use of TCP energy to replace combustion of fuels.

EPA is required to establish National Ambient Air Quality Standards (NAAQS), and has primary enforcement authority. States are required to develop implementation plans for attainment and maintenance of the ambient standards, for EPA's approval. Among the aspects of attainment and maintenance of the NAAQS which vitally concern industrial plants are nonattainment areas, prevention of significant deterioration (PSD), the Offset Policy, new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), best available control technology (BACT), lowest achievable emission rate (LAER), and reasonably available control technology (RACT).

In 1975, as a statutory deadline for attainment approached, at least 160 of the nation's 247 air quality control regions had monitored violations. A strict interpretation of the law would have prohibited new sources from locating in any area which had failed to attain the ambient standard for the pollutant or pollutants it would emit. This would have halted growth in the developed areas of the United States. EPA was forced in 1976 to develop a procedure for permitting growth - the Offset Policy. Its essence is that major new growth is permitted in nonattainment areas only if air quality is *improved* as a result of that growth. The impact on industrial growth in nonattainment areas is tremendous.

The Offset Policy requires major new or modified sources seeking permits to expand in and around nonattainment areas to reduce emissions to the lowest achievable emission rate (LAER); to certify that all sources which it owns or controls in the same State are in compliance; to obtain emission reductions from existing area sources to more than offset the pollution to be added by the new LAER-controlled source; and to demonstrate that a net air quality benefit in the affected area will result.

The Clean Air Act requires that each State Implementation Plan include a comprehensive, accurate, current inventory of actual emission from all sources in nonattainment areas. The purpose is to quantify the origins of the nonattainment problem and, by periodically revising and updating the inventory, to insure that reasonable further progress toward attainment is demonstrated. To achieve an "attainment inventory" may require very substantial reductions in the "baseline inventory" assoociated with nonattainment. State Implementation Plans must include "reasonable further progress schedules" and provisions for new source review to insure that the NAAOS will be met on time - by 1982 to 1987.

Nonattainment provisions are intended to achieve and then to maintain ambient standards. Other parts of the Clean Air Act are intended to prevent significant deterioration of air already cleaner than the ambient standards. The PSD regulations originally prohibited construction of stationary sources in any of 19 specified categories unless EPA, or a State to whom responsibility had been delegated, issued a permit evidencing that the source would apply best available control technology (BACT) for SO_x and particulates and that emissions of these pollutants would not cause significant deterioration of clean air. The 1977 amendments are along the same line but more comprehensive and restrictive.

Without delving further into the many complex aspects of air quality standards and regulations and their trends, it is safe to say with regard to the future that existing regulations will continue to make industrial growth very difficult and expensive even without a shift from oil to gas to coal. As industry is forced by regulation or by cost and scarcity to switch from burning oil to burning coal, prevention of significant deterioration of air quality would require expensive new facilities; stack gas cleanup; very careful handling of coal; and acceptable provisions for handling and disposing of fly ash, grate ash, and sludge from desulfurizing, which contain hazardous materials.

At present, stringent Federal emission-control requirements are not imposed on small industrial plants. As attainment deadlines approach and emission inventories must be reduced, the expectation must be that even small plants cannot escape.

Clean fuels of the future might include coal-derived synthetics or hydrogen. While coal-derived organic fuels presumably would contain no ash and negligible amounts of sulfur, the combustion process would require careful control to insure that emissions of nitrogen oxides, carbon monoxide, and hydrocarbons are within allowable limits. Hydrogen, often called the cleanest of fuels, produces oxides of nitrogen when combusted in air at boiler temperatures. Closed-loop methanation of TCP gas would produce no pollutant emissions.

3.2.1 Greenhouse Effect

That the definition of air pollutant emission may be broadened to include CO_2 is a possibility. The decision is not yet in on the impact on the earth's climate of the increasing level of atmospheric carbon dioxide which appears to be associated with burning organic fuels. A workshop held in February 1978 at the International Institute for Applied Systems Analysis in Austria, sponsored by the World Meteorological Organization, the United Nations Environment Programme, and the Scientific Committee on Problems of the Environment, issued a statement(3-2) from which the following excerpts are taken:

> "We believe that present knowledge is sufficient to require both broad and deep study of many alternative energy supply systems, but does not yet warrant a policy of curtailment of fossil fuel use.
>
> "Policies to emphasize the use of coal because of its great abundance in preference to nonfossil (non CO_2-producing) energy supply systems are equally unjustified.
>
> "Environmental impact assessments of escalating energy use must be performed with greater depth than in the past and on a scale commensurate with the potential importance of the problem.
>
> "Mankind needs and can afford a time window of between five and ten years for vigorous research and planning to narrow the uncertainties sufficiently so as to justify a major change in energy policies to those that are more responsive to the CO_2 problem from those that allow continued reliance on abundant and inexpensive fossil fuels.

"We urge the maintenance of great flexibility in energy supply policies at this time".

3.3 ENERGY CORRIDORS

Massive opposition to construction of either overhead electrical transmission lines or buried pipelines has developed. The opposition has been manifested not only in litigation, but also in armed confrontation. The implementatin of HTR-Multiplexes will be faced with this problem, but to a lesser degree than central power plants depending entirely on electrical transmission.

Examples from a single state, Minnesota, will serve to illustrate the issues which have been raised and how they have been met. One of the issues is the power of the state to condemn private lands. An Associated Press article in June 1979 described "battle lines drawn over eminent domain". The battlefields are the valuable farmlands through which power lines or pipelines must pass in order to carry electricity or fuel to St. Paul and Minneapolis.

Landowners filed suit to stop the laying of a crude oil pipeline through southern Minnesota. Demonstrators sought arrest and were arrested on trespassing charges resulting from a planned and publicized protest event in October 1978 at a power-line converter station near Delano, Minnesota; they were subequently acquitted by a jury. The Minnesota Supreme Court in April 1978 reversed a state agency's approval of an electric power line route adversely affecting a lake and a virgin oak forest, ruling the agency improperly balanced environmental consequences of the selected route and the potential human impact of a feasible alternative. The high court decision establishes the primacy of the Minnesota Environmental Rights Act over other specific statutes involving power-line siting, and asserts a policy of nonproliferation. The chosen route, giving rise to the litigation, allegedly would have impaired, polluted, or destroyed a lake and a 130-acre virgin oak woods. The alternative route, along existing power lines, had been rejected by the Minnesota Environmental Quality Council because it would involve condemnation of several homes. The Minnesota Supreme Court noted that loss of homes "can be fully compensated in damages", but loss of natural resources "is noncompensable and injurious to all present and future residents of Minnesota".

Large central power plants are faced with the "getaway problem" - the aesthetic difficulties caused by a transmission corridor filled with high-tension overhead power lines. If a substantial fraction of the energy output from a plant were carried underground, the width of the transmission corridor could be reduced accordingly. Once the underground pipelines are installed, the only aesthetic problem is the need for access, which may require keeping rough roadways cleared through wooded areas. Avoiding pristine lakes and virgin forests is easier with pipeline routing than with overhead transmission.

HTR-Multiplexes may be relatively small and dispersed, or concentrated in one or a few locations to reduce the number of sites requiring approval. If small sites at distances of a few tens of miles from load centers are chosen, undergrounding of both TCP and electrical cables becomes feasible, because cables carrying voltages up to perhaps 69 kilovolts are readily buried. There should be no "getaway problem". If concentrated energy centers are developed, they presumably will be at considerable distances from load centers and will require high voltage transmission to carry electrical power efficiently and economically. However, whatever fractrion of the energy output is conveyed in thermochemical pipelines should cause less problem than the overhead lines and help to mitigate "getaway" and eminent domain problems.

3.4 ENERGY INDEPENDENCE

Energy self-sufficiency is as vital to the national security of the United States as are its armed forces. A willingness to use the oil boycott as a political weapon has been amply demonstrated by OPEC nations.

Alternative energy sources must be developed in parallel with increased production (accelerated depletion) of domestic gas and oil, so that the alternative sources will be in place and operating within 20 years. Otherwise, we face even greater dependence on imports which already poses an intolerable threat to national security.

3.4.1 Increasing Domestic Oil and Gas Production

A national policy to encourage domestic discovery and production of gas and oil in order to reduce dependence on imports is, at best, a temporary palliative. There is no reason to believe the United States will regain energy self-sufficiency through any combination of conservation and increased domestic production of gas and oil. Domestic production might be sustained at its present level for 20 or 30 years before recoverable resources are depleted.

3.4.2 Coal and Nuclear Alternatives

The only two meaningful candidates for filling gaps in national energy needs after domestic oil and gas supplies are depleted are coal and nuclear fuel. Geothermal, solar, and solar-related sources can supply, at most, 20 to 30% of national energy needs by the year 2000 (unless energy demand is greatly reduced, by a massive disruption of the economy).

The nation's leaders recognize that phasing in the use of coal and uranium to achieve energy independence requires prompt action, if the necessary infrastructure is to be in place by the time domestic gas and oil supplies are depleted. However, the necessary mechanisms continue to be discussed rather than implemented. A strong case can be made for acting quickly enough to extend the life of domestic gas and oil resources so they can continue, for a while longer, to be used for transportation and for petrochemical feedstock. The national minimum-cost trajectory probably is along this path, but prospects for achieving it are dim.

A recent analysis by the Government Accounting Office(3-3) examines the implications and tradeoffs of nuclear power. Coal production is assumed to reach 2 billion tons per year by 2000 *(more than 3 times the 1978 consumption of 623 million tons)*. The GAO report concludes that, if actions are taken to limit or halt the growth of nuclear power, they must be accompanied by actions to severely limit electricity requirements or by programs to expand coal supply or other non-nuclear fuels. Otherwise, serious shortfalls of electricity supply are likely to occur in the 1980s. GAO finds that 2 billion tons of coal per year will supply projected electric-generation needs and also industrial needs in the year 2000 *only* if nuclear plant installation grows according to pre-Three Mile Island projections - 340 GW of electric generation capacity by the year 2000.

3.4.3 Conservation

One of the few points of agreement among environmentalists, industry, and governmental branches is that conservation is important to our national energy future. Two types of conservation are considered: one requires action and