ALTERNATIVES FOR THE TEXAS ELECTRIC POWER INDUSTRY:

Research Project N/T 4

Conducted for the
Governor's Energy Advisory Council

An analysis of alternative technologies for
the generation and transmission of electric
energy for the period 1983-2000.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF GRAPHS

I. INTRODUCTION

The Project N/T-4 Research Group headed by Dr. H. H. Woodson and Dr. C. D. Zinn as co-principal investigators has conducted an assessment of the impact of new technologies on electric power generation and transmission in Texas for the period 1982 to 2000.

The Research Group closely coordinated its efforts on this project with the electric utility industry in the State of Texas. This was accomplished by having an Advisory Council composed of engineers from several electric utility companies that do business in Texas. The Research Group met with this Advisory Group to discuss its conduct of the research project and the results that were obtained. The Research Group is indebted to the Advisory Group for its interest and active participation in this project.

In carrying out its task the Research Group consulted with the electric utility industry, manufacturers of equipment for the industry, engineers on the faculty of the University of Texas at Austin, and other researchers in the various fields of interest both at professional meetings and via written communications. Additionally, the Research Group obtained valuable information from United States government reports, technical papers and journals, and the University of Texas library.

A summary of the Research Group's Assessment of the technologies that will have an effect on electric power generation and transmission is contained in Part II of this report with detailed data and supporting information being given in the text in Part III.

II. SUMMARY

This report contains an assessment of the technologies that have an impact on the generation and transmission of electric power for the State of Texas for the time period 1982 to 2000.

A general broad opinion that has resulted from this research work is that for the next ten to fifteen years the devices that will be used for generation and transmission of electric power in the state will be based upon currently existing technology. This means that new central station power plants will be either nuclear in the form of light water reactors, PWR's or BWR's, with a relatively small fraction being HTGR's or fossil fueled units that burn coal or lignite in a direct combustion process utilizing stack gas clean up systems to meet environmental pollution regulations. Transmission facilities will be primarily high voltage overhead type systems with some underground installations being required in special geographic areas where laws and regulations make underground systems feasible from an economic point of view. These transmission systems will be 345 KV systems, a technology which is currently commercially available, and 765 KV systems also currently available, when the amount of energy to be transmitted warrants their installation.

A number of other technologies offer some prospect of having an impact on the generation of electric power during the period 1982-2000 The breeder reactor, either Liquid Metal Fast Breeder Reactor (LMFBR) or the Gas Cooled Fast Reactor (GCFR), appears to have good prospects for being developed as a commercial process. A significant amount of developmental work has gone into this concept and will continue as industry and AEC interest in this area is high. The significance of the development of an economical commercial breeder reactor is its lower fuel cycle cost when compared with current reactor types. This feature results in the conservation of nuclear fuel resources and has the prospect of producing electrical energy at a lower cost than that produced by current reactor types. Even though the breeder reactor has these attractive features, it is not without developmental problems. The cost of developing the LMFBR demonstration plant has escalated dramatically with the most recent figure being quoted as 1.74 billion dollars. The GCFR project has not received funding for its development on anything approaching the levels that have been allocated to the LMFBR project. The GCFR system development requires an extension of the current HTGR technology in many respects and because of this it seems reasonable to expect that the GCFR system can be developed at an earlier date than the LMFBR. However, it should be noted that even though demonstration plants for each type are being planned there is no reason to expect the development of these systems to be completed in a shorter time than has been required for previous reactor types. This translates into the opinion that an economical commercial breeder reactor system will not be available until the mid to late 1990's which leaves little time for this system to have an appreciable effect on electric power generation for the period 1982 to 2000.

Fusion power is another nuclear system that may be useful for the production of electrical energy. The major advantage to be gained by the development of this process is that the supply of fuel that is used is practically limitless. With the prospects for shortages of known fuels this is a most important feature for future energy production.

The outlook for the development of a commercial fusion reactor system before the year 2000 is not promising. Fusion reactor systems are in a very early stage of research and development. Many significant technological problems remain to be investigated and the prospects for quick solutions are not bright. It is therefore the opinion of the research group that fusion power will not have an impact on the generation of electrical energy during this period of interest.

The utilization of gas turbines for the generation of electrical energy represents one of the more promising alternatives that seems likely to be available throughout this period. In fact, gas turbine technology is well developed and manufacturing capacity exists. In their present stage of development, gas turbines have been used primarily as a means for satisfying peaking power requirements. A possibly more significant use of gas turbines is their application in a combined cycle with conventional fossil fueled plants. The major impact in this area is the potential for improvement in plant thermal efficiencies of from 5 to 10 percent. This results in conservation of fossil fuel resources which are becoming increasingly more expensive. In fact, the single most important factor in the increased utilization of gas turbines is the problem of securing a reliable fuel supply as gas turbines require high quality liquid or gaseous fuels. The most promising solution to this fuel supply problem appears to be the development of an efficient coal gasification process. Several coal gasification processes that produce low to mid BTU quality gas are either in existence or under development. In addition, there is extensive interest in the development of a high BTU coal gasification process. The development of these processes will provide a reliable fuel supply and thus promote the use of gas turbines particularly in combined cycle applications. The most important factor involved with the current gasification processes is a matter of economics. When gas produced by these processes is competitive economically with other energy sources gas turbine combined cycle plants are very likely to have increased importance in the area of electrical energy production. It is the opinion of the research group that efficient low to mid BTU coal gasification processes will be available by the early 1980's.

The development of fuel cells will provide another generation alternative with some unique attractive features. The use of fuel cells would allow generating sources to be distributed around the service area and thus by locating these near load centers transmission systems could be reduced. Fuel cells have been in an advanced developmental stage for a few years with small packaged units demonstrating their potential. Fuel cell development is now concerned with demonstrating reliable operation of larger units, approximately 26 MW, and with solving some technological and economic problems involving the fuel processing and electric power conditioning parts of the system. These developments, especially the economic considerations since again fuel cells depend upon a high quality liquid or gaseous fuel source, are somewhat uncertain. The research group estimates that another eight to ten years will be required to solve these problems and even then fuel cells will contribute only a minor amount of the electrical energy that will be required.

Obtaining electric energy by utilizing naturally occurring energy sources has recently received a great deal of attention. The most prominent among these are solar energy, wind energy, and geothermal energy. These forms are mentioned here together because they are all in a very early stage of development and because in the opinion of the project research group they will have only a minor impact on the generation of electric energy for the next twenty years.

The direct conversion of solar energy is receiving a great deal of interest in terms of funding of research projects by the federal government. However, no large scale economical direct conversion devices have as yet been demonstrated. The research group's assessment is that this development is not likely to occur on an economical scale within the next twenty years. The most probable impact of using solar energy will be its use on a small scale in terms of providing heating and cooling for individual buildings which would result in a decrease in the demand for electric energy.

The production of electrical energy from wind energy has many features that are similar to solar energy. Although devices have been constructed for converting wind energy to electrical energy, significant economics problems exist. The number of wind driven devices required to produce a large amount of electrical energy is enormous and the land use required for these devices is quite high. A further complicating factor is the existence of sufficient winds is confined to a fairly limited geographical area and even in these areas its variability presents significant problems involving matching energy production to energy demand.

The production of electrical energy from geothermal energy involves converting the thermal energy of certain rock formation into electrical output. This requires the development of energy conversion devices that can economically perform this service. The major problem involved with using this energy resources is its thermal quality. Although there is a source of this energy in California that is being used to produce electrical energy, it is generally true that high quality geothermal sources have not been found. Most of the geothermal resources possess relatively poor thermal properties and it is not likely that economical processes for using this resource in producing electrical energy will be developed in time to have a significant impact during the period covered by this report.

Systems for transmitting the electrical energy for the State of Texas will be primarily composed of high voltage AC and DC transmission lines. The existing transmission network is composed of AC lines with the highest voltage being 345 KV except for some 500 KV in the southeast part of the State. The future outlook is for the construction of higher voltage AC overhead transmission lines with some DC transmission links being installed when the terminal equipment is fully developed and when the transmission distance warrants the use of a DC line. The 345 KV system with some extensions will probably be satisfactory for transmitting the electric power demands of the State for the next ten to fifteen years. The next step up from this will most likely be to a 765 KV system but this will not be required until the amount of power to be transmitted makes this a desirable system. The technology exists for building AC lines of higher voltage although there are some problems associated with their operation.

Systems operating at 765 KV have been installed and operated by an electric utility in the United States. Some problems involving radio and television interference and minor electric shock have been encountered with the operation of this system. These problems do not appear to be insurmountable by good engineering design so these systems should be able to be built and operated safely. Test lines operating in the range from 1000 to 1100 KV have been constructed. The operation of these systems indicates that they can be built and operated satisfactorily. The major advantage of higher voltage systems is that more energy can be transmitted per unit of land consumed for right of way and terminal use and that less energy is lost as a result of transmission.

No major DC transmission lines have been built in the State of Texas. The major drawback to their use has been the cost of the terminal facilities and the lack of a reliable DC circuit breaker. A major developmental effort is currently being conducted in order to develop this circuit breaker. This should be accomplished within the next ten years and the construction of DC transmission lines should become more attractive. These lines offer the prospect for a savings in lost energy due to transmission when compared with equivalent AC systems and having the potential for improving reliability and stability in the operation of a transmisison system.

Research and development is being conducted on several alternative methods for transmitting electrical energy. These systems range from transmitting electrical energy via superconducting or cyrogenic systems to charged particles flowing through a duct network. Each of these systems has technological and economics problems to be overcome before they can make any impact on the transmission of electrical energy. This is not expected to occur prior to the mid to late 1990's.

A detailed discussion of the supporting data upon which these comments are based may be found in the text of this report.

III. TEXT

A. Generation Technologies

1. Existing Reactor Technologies

a. Light Water Reactors

Most of the operating nuclear power plants built or scheduled to date are light water reactors. These plants are light water cooled and moderated. In these reactors, the fission of enriched uranium-235 is caused by the capture of thermal (slow) neutrons. The neutrons are born at fission with high energies and are moderated or slowed down to thermal energies by collisions with hydrogen atoms in the water molecule. In the course of this moderation, a fraction of the neutrons are lost by parasitic capture, a condition which is reduced in a fast reactor. These light water moderated reactors are called burners because they are net depletors of fissile material. There are basically two types of light water reactors, the pressurized water reactor (PWR) and the boiling water reactor (BWR).

In a pressurized water reactor plant as shown in Figure 1, the system is kept under high pressure to maintain the water in a liquid state. The water heated in the reactor is circulated through a steam generator where it transfers its heat to water and steam. The steam is then used to drive a turbine. Babcock and Wilcox, Combustion Engineering and Westinghouse manufacture the PWR nuclear steam supply system.

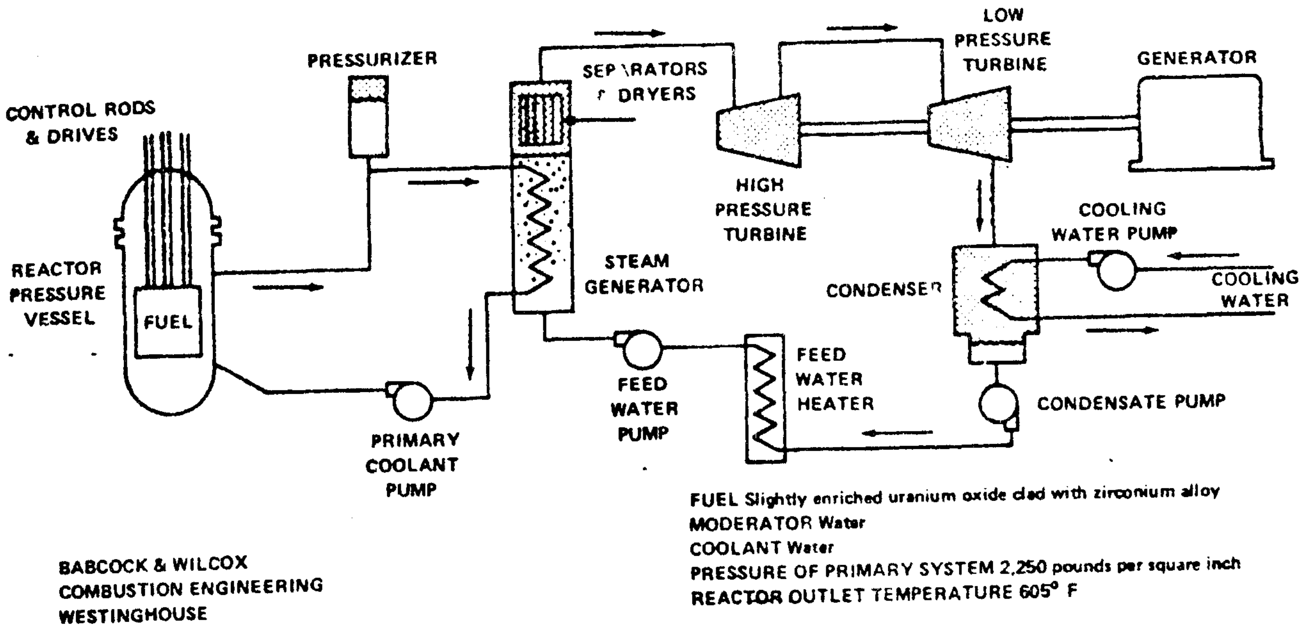


Figure 1 Pressurized Water Reactor Power Plant

The boiling water reactor shown in Figure 2 utilizes a single loop in which boiling occurs in the core. Steam generated by this boiling water is dried to the maximum extent possible in the reactor and is sent directly to the turbine. General Electric manufactures the BWR nuclear steam supply system.

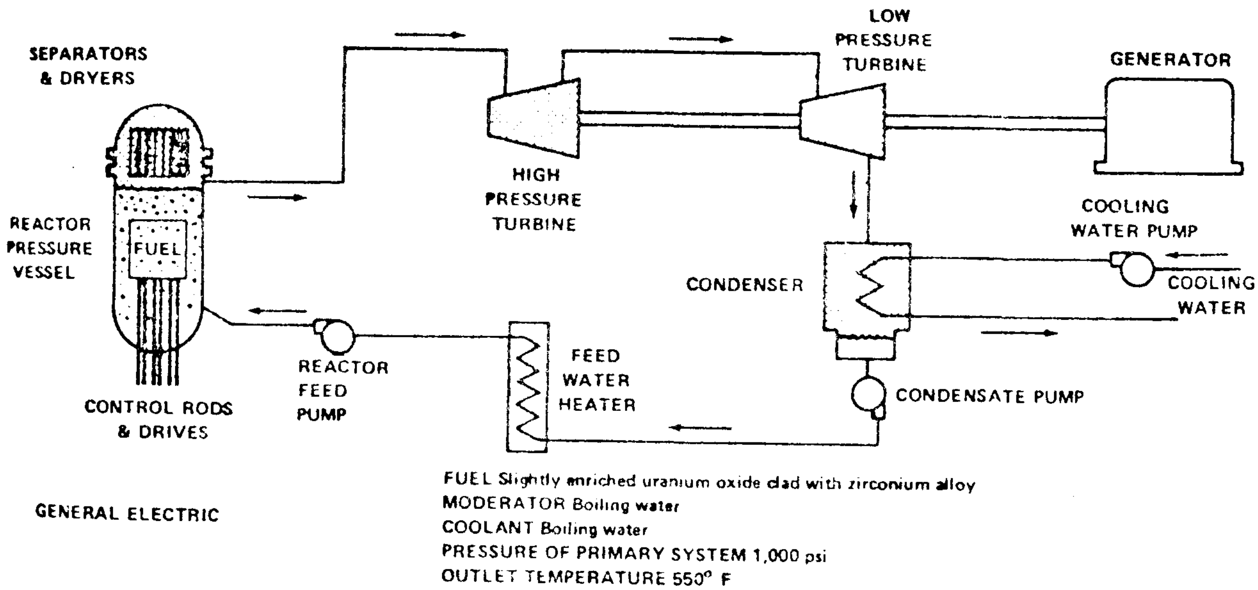


Figure 2 **Boiling Water Reactor Power Plant**

Costs: The reliability of service, the quality of service, and the cost of electric energy are the essential concerns of all utility companies. After considering the technical factors involved, the utilities make their selection based on economic factors. There are three main components of total power generation costs, capital costs, fuel costs and operation and maintenance costs. Table I presents data on the range of estimated capital costs for selected 1000 MWe power plants scheduled for commercial operation in 1981, which was derived from data calculated by using the "Concept" computer code developed at Oak Ridge National Laboratory. Lead times, time from contract award to commercial operation, were assumed to be 7 1/2 years for nuclear and 6 years for fossil plants.

TABLE I

Range of Estimated Capital Costs for
Selected 1,000 MWe Central Station Electric
Power Plants for Commercial Operation

In 1981 ($/KWe)

	Nuclear (LWR)	Coal	Oil
Direct costs			
Land	1	1	1
Structures & site facilities	44-60	28-39	26-35
Reactor or boiler plant equipment	78-84	75-86	62-72
Turbine plant equipment	83-94	66-76	66-76
Electric plant equipment	28-32	16-20	15-19
Miscellaneous plant equipment	5-6	56-58	4-5
Contingency & spare parts allowance	18-22	18-22	13-16
Subtotal	257-299	260-302	187-224
Indirect costs			
Professional services	43-47	23-25	20-22
Other costs	28-21	29-32	20-23
Interest during construction (7%/year)	83-95	74-85	53-63
Subtotal	154-173	126-142	93-108
Total plant cost (no escalation	411-472	386-444	280-332
Escalation during construction			
at 4%	74-86	72-81	50-61
at 5%	94-110	87-99	61-74
at 6%	115-134	103-118	73-88
at 7%	137-160	119-137	85-102
at 8%	159-186	136-157	98-117

The relative proportion of capital, fuel and operation and maintenance costs differs among gas, coal, oil and nuclear installations, but utility management bases its decision on the sum of these costs appropriately weighted over the life of the plant. Whereas the capital cost of nuclear power plant equipment is higher than that of fossil power plants, the fuel costs are considerably lower. Operation and maintenance costs of nuclear plants are lower than costs of coal plants with SO_2 removal systems but higher than those of oil palnts. However, the total cost is such that nuclear, coal, and oil actively compete with each other for new capacity additions. While gas fueled power plants have the lowest power generation cost, the lack of availability of gas precludes any appreciable further increase in the use of natural gas for generating electric power. For oil the choice is highly dependent on price and assurance of supply. Table II compares estimates of total busbar generation costs for nuclear (LWR), coal and oil plants for commercial operation in 1981.

TABLE II

Estimated Generation costs for 1000 MWe steam electric power plants including escalation to 1981 (Mills/kwh)

	LWR	COAL	OIL
Capital.	11.7	10.9	8.0
Fuel	2.5	5.5	24.6
O & M	1.0	1.6	0.8
Total.	15.2	18.0	33.4

Pressurized water reactors and boiling water reactors comprise the majority of the commercial reactors that have been built in the United States. The technology associated with these reactors is well developed and a significant amount of operating experience has been accumulated by the utility industry. In spite of the somewhat undesirable feature of relatively low efficiency of these plants when compared with modern fossil fueled units (approximately 5% lower) and gas cooled reactors, the light water reactors will likely continue to dominate the nuclear generation field for another ten to fifteen years. This is due to the present stage of development of the manufacturing processes, the fuel fabrication and reprocessing facilities, and the on site fabrication, testing and operation techniques that are currently in existence on a commercial scale. In addition, the economics associated with plants of this type are well developed. In fact, the light water reactors are the only types for which the previous comments are true in the United States since no other reactor types have yet been operated on a full scale commercial basis.

One should not infer from this discussion that light water reactors should be taken as the only practical nuclear alternative. In fact, even though they are well developed as commercial processes, light water reactors have several undesirable features such as the consumption of a relatively scarce and expensive fuel (U-235), and relatively low thermal efficiencies, that stimulate an interest in the development of other nuclear reactor types.

b. High Temperature Gas Cooled Reactors

The technological status of the HTGR can be supported by the fact that the HTGR is now commercially available as an alternate souce of electric power generation. To arrive at this stage General Atomic (formerly known as Gulf General Atomic), in co-operation with the AEC and assisted by a group of 53 electric utilities started work in 1959 on developing the prototype HTGR-Peach Bottom I. Peach Bottom I is a 40 MWe unit and has been in commercial operation since 1967. This plant has generated 467,353 MWh (452 equivalent full power days) of electricity with its first core and 517,000 MWh (500 equivalent full power days) with its second core through January 1973. Plant operating experience with the second core has been generally satisfactory and Philadelphia Electric company which as operated this plant, has decided that its objective has been largely completed and is considering shutting down this unit sometime this year.

A second generation plant , the 330 MWe Fort St. Vrain was purchased by Public service company of Colorado and was designed and constructed by GA. The pre-operational testing program, which encountered difficulties that caused slippages in the schedule is now complete and estimates are that commercial operation will begin sometime this year.

General Atomic Company currently sells two types of commercial HTGR's - a 1160 MWe unit and a 770 MWe. Table III shows the different units which have been bought by various utility companies in the United States.

TABLE III

Utility	Unit Size	Estimated Date of Operation 1st Unit	2nd Unit
Philadelphia Electric	2-1160 MWe	1983	1985
Delmarva Electric	2-770 MWe	1980	1982
Louisiana Power & Light	2-1160 MWe	1984	1986
Ohio Edison	2-1160 MWe	1984	1986
Southern California Edison	2-1540 MWe	Late 1980's	
American Electric Company	2-1540 MWe	Mid 1980's	

In January of 1974 General Atomic and American Electric Power Company, the nation's largest investor owned electric utility system, have initiated a joint program whose objective will be to design a standardized 1540 MWe HTGR. The Department of Interior has forecast construction of 181,000 MW of HTGR capacity by the year 2000.

Advantages of the HTGR: The HTGR offers potential advantages that span economic and environmental categories. One set of advantages arises from its higher temperature and therefore higher thermal efficiency (40%) which is comparable to modern fossil fueled plants. This not only improves performance, conserves fuel, lowers capital costs and permits the use of conventional turbogenerating equipment; it also reduces the amount of cooling water required to carry away waste heat. Furthermore, its employment of a combination of graphite core structure and helium coolant facilitates maintenance and helps to decrease fuel costs. Its utilization of thorium in the fuel cycle instead of U-235, improves the conservation of nuclear fuels.

Thermal Discharge: Because of the higher thermal efficiency of the HTGR (39%), it rejects about 35% less heat to the surroundings than does an LWR of the same rated electric output. This results in (a) lower temperature water discharged from plant condensers, (b) smaller cooling water flow rates, with consequent savings in intake and discharge structures, (c) less makeup water requirements for cooling tower sites, (d) ease of siting restrictions and increased acceptability to local communities.

Make Up Water Requirements: If river or ocean once through cooling is employed and a 15°F rise in temperature is permitted, an 1160 MWe HTGR will require 823,000 gallons/minute of circulating water, while a light water reactor of equal size will require 1,067,000 gallons per minute.

If wet cooling towers are employed for heat rejection, the towers for a LWR are approximately 1/3 larger and proportionately more expensive than the towers for an HTGR. The evaporative losses from the towers are also reduced, hence the makeup water required for a 1160 MWe HTGR is 24,000,000 gallons per day compared to 35,000,000 per day for a LWR.

For cooling ponds, the higher thermal efficiency of the HTGR means more electric megawatts can be sited on a specific pond at the same equilibrium pond-water temperatures.

Dry cooling towers can be used for heat rejection if political, regulatory, or environmental pressures are sufficient to eliminate consideration of either, once thru cooling, cooling ponds or wet cooling towers. The dry cooling towers for a LWR would be approximately 1/3 larger and proportionately more expensive than those for a HTGR. Also the generating capacity loss under conditions of high air temperature or humidity will approximately be one-half the capacity loss with a comparable LWR. Thus if necessary the HTGR plant can be located on a remote dry site with a minimum cost penalty relative to the LWR.

Releases of Radioactive Wastes: During normal operation, a HTGR discharges only very small amounts of radioactive wastes to the environment. Two of the principal reasons for this are that the helium coolant is essentially free of induced radioactivity and that the tritium created does not become lost in large volumes of water but is captured in solid absorbers. Shown below are the projected effluent releases of radioactivity in the effluents of reference 1000 MWe power reactors as reported in [66].

	Air Borne Effluents (Ci/Yr)		Liquid Effluents (Ci/Yr)	
	Gaseous	Halogens & Particulates	Fission and Corrosion Products	Tritium
BWR	1.66×10^6	5.31	49.6	104
PWR	9,650	0.17	30.2	5,750
HTGR	2,760	<0.02	0.27	835

The solid wastes generated by a 1160 MWe HTGR total only 610 cubic feet and less than 20,000 curies/year. Approximately 80% of this total is represented by the removable graphite reflector blocks, which are only slightly contaminated and can be shipped off-site in drums for burial or burning with virtually no effect on the environment. The remaining 20% can be shipped off-site in shielded 55-gallon drums for burial.

Liquid wastes result chiefly from decontamination of primary system components prior to maintenance. Both quantity and activity are low (about 2500 gallons and 20 curies per year for a 1160 MWe plant). They can be satisfactorily handled by packaging and off-site burial if required.

Helium purification and gas recovery systems provided as part of the NSSS, reduce the anticipated levels of gaseous releases to essentially zero (less than 1/10,000 of the current allowable release levels specified in 10 CFR 20). Tritium generated within the primary system is removed by the helium purification system as a solid waste on titanium sponge.

Safety Features of HTGR: Some important safety factors of the HTGR are due to the inert gas helium, the mechanical and chemical stability of the core materials and the integrity of the PCRV.

The use of thorium mixed with uranium as a fuel provides a built-in automatic temperature control. As the temperature increases, the rate of fission promptly decreases in a manner similar to the decrease in fission rate in a PWR as the moderator temperature is increased.

The use of a large mass of graphite as the moderator ensures that the effects of any sudden changes of temperature in the core will be slow and readily controllable. The HTGR graphite core can absorb roughly 20 times as much heat per degree of temperature rise as can the LWR cores.

The use of helium as the coolant means that reactivity does not respond to changes in coolant density.

The containing of the entire reactor coolant system within the PCRV eliminates the possibility of a rupture in external coolant piping and of any sudden loss of primary coolant.

In addition to these safety features the HTGR includes a number of engineered design safety features: (a) a core auxiliary cooling system as an independant backup, (b) a reserve shutdown system independant of the normal control rod system, (c) a steam/water detection and dump system to minimize the amount of water that could leak into the coolant as a result of a steam generator tube or superheater leak.

Conservation: The UTGR's thorium-uranium fuel combination means that over its 40 year life span the 1160 MWe HTGR is capable of conserving more than 2000 tons of uranium (U_3O_8) over the needs of a comparable sized LWR.

The relative high thermal efficiency of the HTGR means that, compared to a LWR of comparable size, the 1160 MWe HTGR typically conserves 9,000,000 to 11,000,000 gallons of water a day -- enough to supply the needs of a city of 60,000 people.

Operation of a HTGR: A schematic flow diagram of the HTGR is shown in Figure 3.

The HTGR nuclear power system uses Uranium-235 to initially fuel the reactor, thorium 232 as the fertile material which is converted to Uranium-233 fuel; graphite as the moderator, cladding structure, and reflector, and helium as the coolant. The helium gas at moderate pressure is circulated through the reactor, the piping and the steam generator. The high temperature gas transfers its heat across tube walls to water and steam in a secondary system and then is returned to the core. The generated steam is then used to drive a turbine to produce electricity. The general arrangement of a HTGR, core, PCRV steam generators and helium circulators is shown in Figure 4.

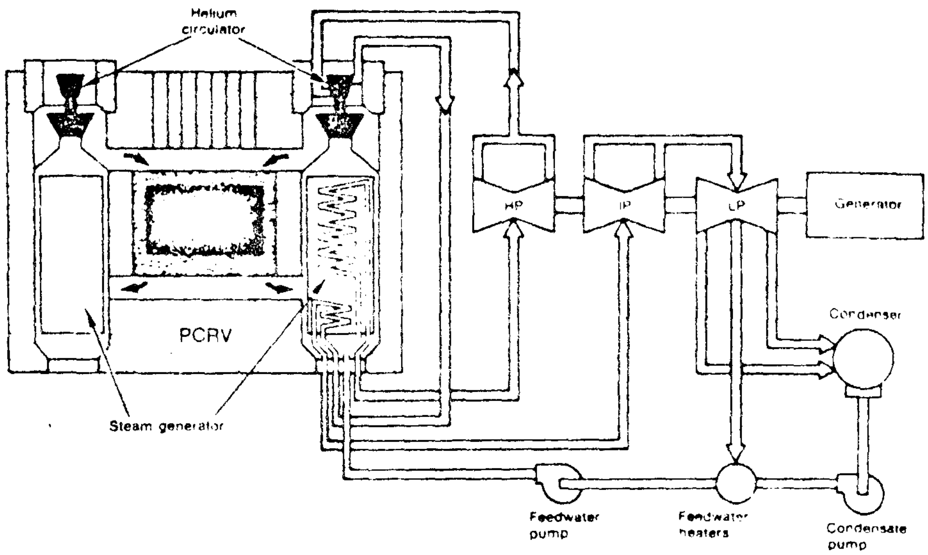


Figure 3 Schematic Flow Diagram (of major components and systems of 1,160 Mw HTGR)

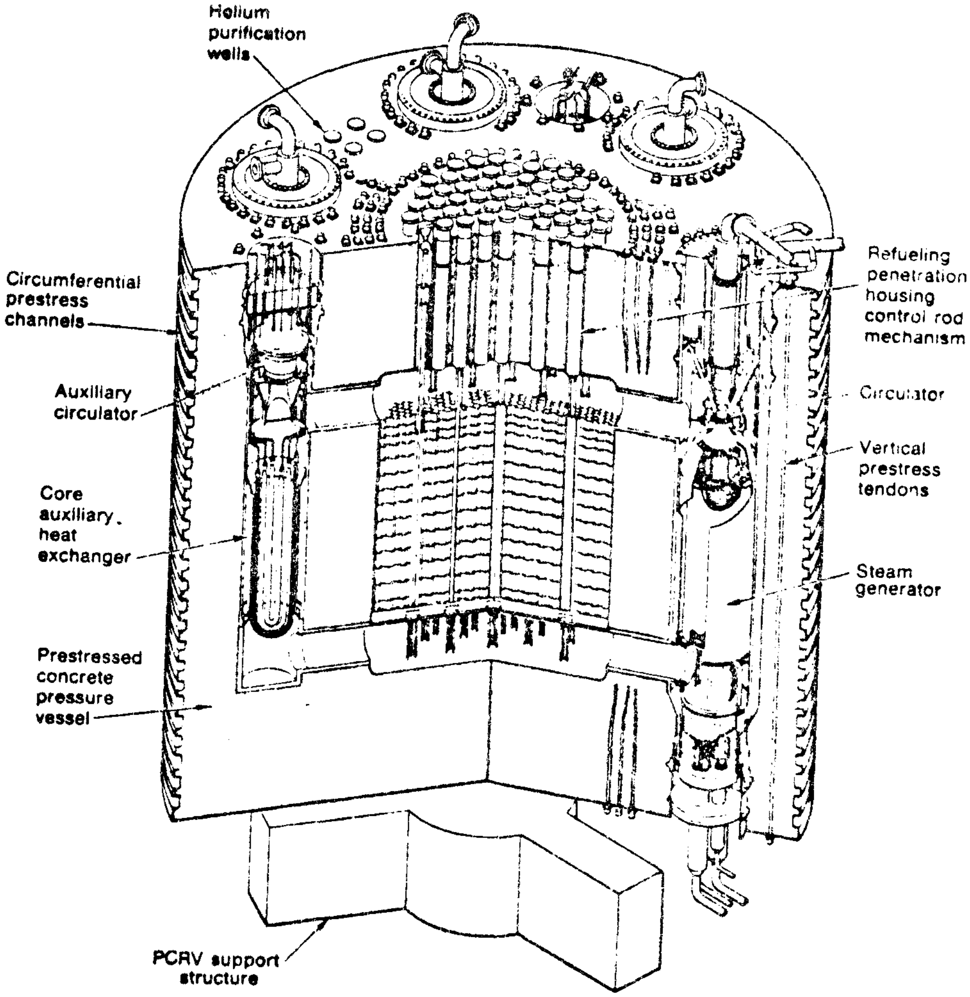


Figure 4 General Arrangement
(of HTGR core, PCRV, steam generators, and helium circulators)

Cooling Water Systems for HTGR's and LWR's: Economic cost comparisons for the nine viable circulating water cooling systems for application to LWR's versus nine similar circulating water cooling systems for application to HTGR's are shown below. Case 'A' pertains to LWR's and 'B' to HTGR's.

Case No.	Type Reactor	Type of Cooling System	Circulating Water System Capital Cost $1,000	Circulating Water System Unit Energy Cost Mills/Net KWhs
ECO 1A	LWR	Once thru to ocean	28,938	0.463
ECO 1B	HTGR	"	20,351	0.357
ECO 3A	LWR	Natural Draft(Cooling Tower-Salt Water)	41,284	0.664
ECO 3B	HTGR	"	27,270	0.484
MWR 1A	LWR	Once thru to river	28,010	0.451
MWR 1B	HTGR	"	18,694	0.327
MWR 2A	LWR	Mech. Draft Cooling Towers	25,786	0.416
MWR 2B	HTGR	"	19,965	0.354
PNW 2A	LWR	"	30,129	0.484
PNW 2B	HTGR	"	23,017	0.407
PNW 6A	LWR	Dry Cooling Towers	97,673	1.609
PNW 6B	HTGR	"	72,855	1.318
SER 3A	LWR	Natural Draft Cooling Tower	30,896	0.499
SER 3B	HTGR	"	24,279	0.432
SER 4A	LWR	Cooling Pond	24,733	0.395
SER 4B	HTGR	"	18,353	0.323
SER 5A	LWR	Powered Spray Modules	27,117	0.439
SER 5B	HTGR	"	19,990	0.356

The different cases were:

ECO Case: East Cost Ocean site

MWR Case: Midwestern River site

PNW Case: Pacific Northwest site

SER Case: Southeastern River site

The LWR was assumed to be a 4000 MWt nominal base load PWR. The turbine is an 1800 rpm tandem-compound six flow unit with a guaranteed rating of 1316 MWe, a maximum calculated capability of 105% core power of 1367 MWe and a net plant heat rate of 10,290 Btu/KWhr at Max capability.

The HTGR was assumed to be a 3000 MWt reference plant design. The turbine is a 3600 rpm tandem compound six flow unit with a guaranteed rating of 1229 MWe and a net plant heat rate of 8867 Btu/KWhr at maximum capability.

The evaluated unit energy cost in the above tabulation is based upon a plant capacity factor of 0.8. Annual costs of circulating water cooling systems are comprised only of fixed charges on capital investment which as little as one year ago was at an annual rate of 15%. It is interesting to note that today this rate has escalated to 22% due to the increasingly higher cost of capital. Capital costs reflect the installed cost of the circulating water cooling system.

From the above tabulation it is apparent that the HTGR plants result in lower capital investment and unit energy cost for comparative cooling systems as compared to the LWR plants.

Availability of HTGR: General Atomic has indicated that the production capacity to build HTGR's is limited, and further they do not have plans to appreciably increase their production capacity in the near future. In view of this fact, even though HTGR's may represent a desirable alternative, the productive capacity will probably not be available to supply HTGR's for all nuclear reactor applications. It seems likely; however, that if demand for gas cooled reactors increases that other reactor manufacturers may enter the gas cooled reactor market.

The HTGR Gas-Turbine Power Plant: The nuclear gas-turbine has been under investigation at General Atomic since the early 1960's. The current program on the HTGR-GT has been under way since 1970. Various United States utility companies and the U.S. AEC have supported this program. The program objective is to put a commercial plant in operation by the mid-1980's.

Based on several facts this system should be on line by the mid-1980's. For instance the General Atomic HTGR is already developed and has been commercially accepted for modern steam turbine plant use. The major technology required to design and develop the helium gas turbine, heat exchangers, and other components required for the HTGR-gas turbine power plant is already available. Thus, the objective of this design as a power source having a reduced impact on cooling water resources by the mid-1980's is attainable.

The question of why the extensive development of gas turbines should be undertaken when steam turbines are already well developed has several answers. The principal potential advantages seen for a direct cycle nuclear power plant are:

1. More efficient use of the high temperature capability of the reactor without the temperature degradation that necessarily occurs in the steam generator of an indirect cycle plant.
2. Simplification through a reduction in the number of systems and components.
3. A more compact power conversion system due to the high density working fluid achievable in the closed cycle gas-turbine.
4. Economical adaptability to dry cooling.

The efficiency of HTGR-GT is expected to be about 36.8% which is equal to the efficiency of an HTGR-steam turbine plant with dry cooling. But compared with the HTGR steam plant, the HTGR-GT design offers greater siting flexibility and fewer environmental effects from heat rejection, because it does not depend on water for cooling. The HTGR-GT plant can directly discharge waste heat to the atmosphere rather than to oceans, lakes and rivers.

Another advantage is the high potential for further imporvement in efficiency and capacity. The current design is conservatively based on a helium outlet temperature of 1500°F. It appears feasible to raise this temperature to 1700°F in the near future. This would result in an increase of up to 12% in cycle efficiency and an increase of about 28% in power output per unit of helium flow.

Where cooling water is available, the reject heat can be used in a secondary power cycle to achieve an overall efficiency of approximately 50%. Also the reject heat is at high enough temperature to be useful in a large number of industrial and commercial operations including desalination and refrigeration.

HTGR-Gas Turbine-Costs: Total plant costs based in part on cost estimates from turbomachinery manufacturers and an architectural engineering firm, have been estimated. For 1100 MWe plant comparisons, these estimates indicate that the generation cost for a dry cooled HTGR gas turbine plant are:

1. Nearly identical to that of a wet cooled HTGR steam turbine plant.
2. 12% less than that for a dry cooled HTGR steam turbine plant.
3. Substantially less than LWR plants either with dry or wet cooling.
4. Size of HTGR-GT is less than that of a steam plant (See Figure 5)

Operation of a HTGR-GT Power Plant: The system will use direct cycle gas turbines powered by hot helium from a HTGR to drive electric generators.

A schematic flow diagram of the HTGR-GT is shown in Figure 6. The primary fluid helium is heated in the reactor core to 1500°F. It then drives the turbine, and in so doing is expanded. The helium temperature is then 999°F. The turbine drives the compressor and the electric generator, and the helium flows from the turbine through a recuperator (where the temperature is reduced to 426°F) and a water-cooled precooler (where the helium is chilled to 79°F) and into the compressor, where compression raises the temperature to 335°F. The pass through the recuperator high pressure side increases the helium temperature to about 915°F before it re-enteres the reactor core to complete the cycle. The heat picked up by the water in the precooler is discharged into the atmosphere at the dry cooling tower, and the cooled water recirculates through the precooler.

Conclusions: The HTGR-GT offers considerable simplification as compared with the steam turbine and provides a means of continuing power generation while minimizing the environmental and water resources impact. It is suitable for dry air cooled central station generation of electric power and thus does not consume any fresh water for cooling. It can help solve the national need for additional, acceptable power plant sites because these power plants can be located in remote areas such as dry canyons or waste lands. The sites do not have to be adjacent to a large supply of water around which population tends to concentrate. This flexibility in siting is particularly important for the state of Texas due to the critical supply of water for cooling purposes.

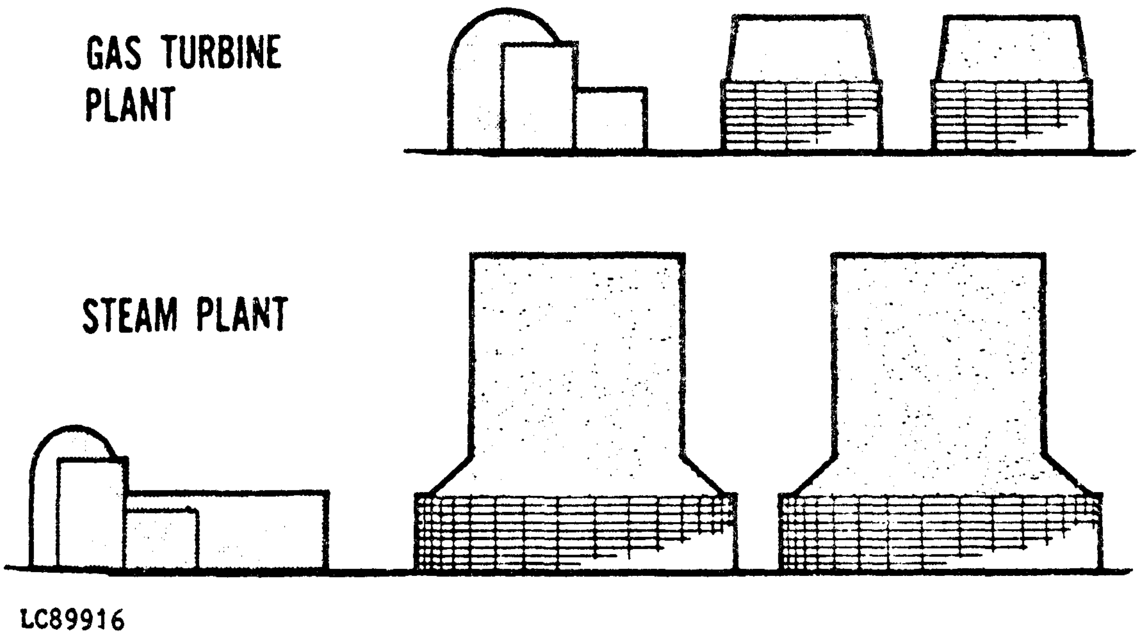


Figure 5 Gas-Turbine Plant Size Versus Steam-Plant Size

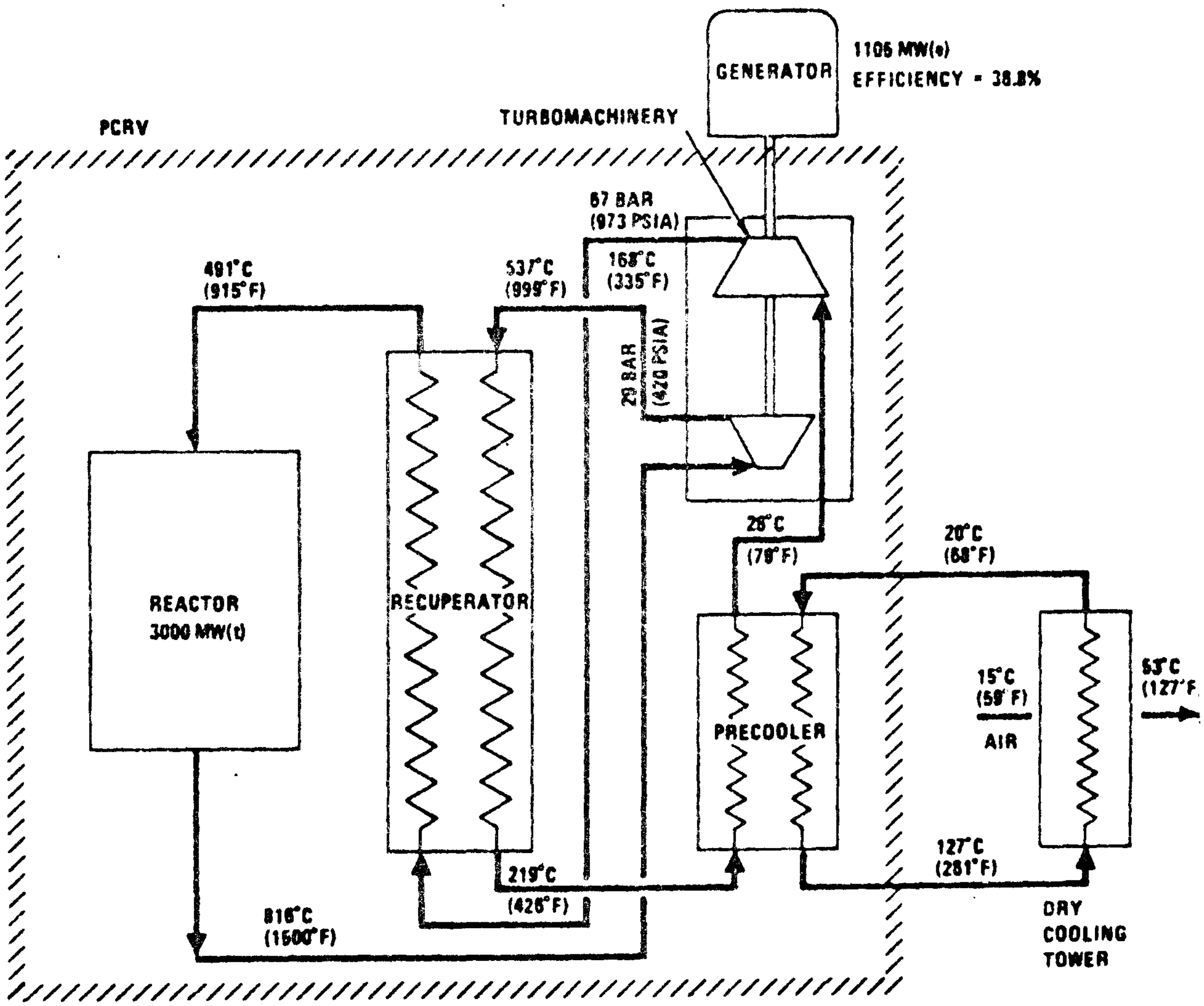


Figure 6 Design Cycle for HTGR Gas-Turbine Power Plant With Dry Cooling

c. Breeder Reactors

Why Fast Breeder Reactors: As it occurs naturally in the earth uranium consists of 0.7% U-235 which is fissionable and is used as the fuel in the present day light water reactors (i.e., PWR and BWR) and HTGR's. The remaining 99.3% of the uranium is the isotope U-238 which is not fissionable. However, the U-238 when placed in the fast breeder reactor captures neutrons and is converted into plutonium which is fissionable.

Figure 7 shows the basic operation of a breeder reactor. The breeder is fueled initially with about 10 to 15% plutonium and the remaining 85% U-238. During breeder operation the initial plutonium fissions and is converted to energy and fission products. Each fission releases two or three neutrons. The U-238 captures some of these neutrons and is converted into new plutonium. As is indicated in Figure 7, the breeder operates so efficiently that the U-238 is converted into new plutonium at rate faster than the original plutonium is used up. Thus at the end of the cycle there is more plutonium in the reactor than there was in the beginning. Hence, the name is breeder.

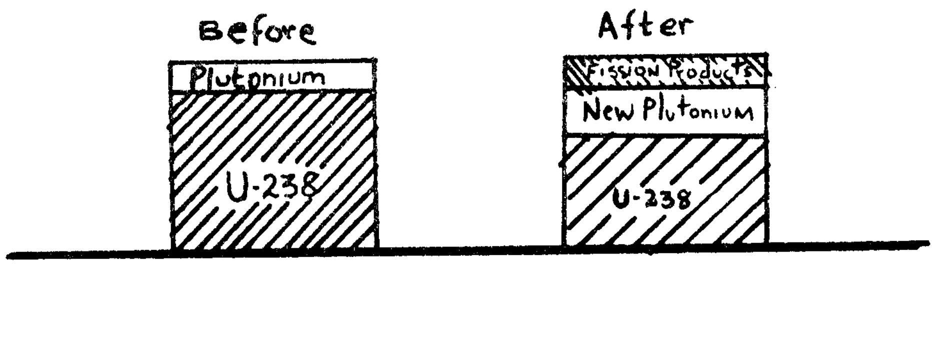


Figure 7 Basic Breeder Operation

In essence, therefore the breeder is able to expand the amount of useful uranium reserves by using the U-238 that is not usable in thermal reactors.

There is enough U-238 stored at Oak Ridge in the tailings from diffusion plants such that if every new electrical power plant built form now until the year 2010 were a breeder reactor, no additional mining would be required. If 2 million tons of uranium were used for water reactors, there would be enough U-238 in the tailings from the separation plants to fuel breeder reactors for the next few centuries without additional mining. Thus a breeder conserves and extends fuel resources, thereby providing the potential for a source of low cost energy for many years, other incentives are reduced ecological effects.

The different fast breeder reactors that have been evaluated in our study are the liquid metal fast breeder reactors (LMFBR), the gas cooled fast breeder reactor (GCFR), and the molten salt breeder reactor (MSBR).

<u>Liquid Metal Fast Breeder Reactor (LMFBR)</u>: The status of the LMFBR technology is indicated by the fact that a large scale (350 MWe) demonstration plant is now being designed for construction at a site near Clinch River, Oak Ridge, Tennessee. Projected cost for this demonstration plant is $1.74 billion and utility companies have pledged their approximate share of $250 million for the project.

Russia has commissioned the world's largest LMFBR BN-350 and has started construction of a 500 MWe BN-600. Fourteen LMFBR's are in design, construction or early start up world wide today in the U.S.A., the U.K., France, Germany, Italy, Japan and Russia.

The largest item in the AEC R & D budget is for the development of the LMFBR. The program is a highly diverse one including basic materials and reactor physics studies, engineering design, component development and testing and analysis.

The LMFBR uses sodium as the coolant, there are two sodium coolant loops, the primary loop transfers heat from the reactor core to a non-radioactive secondary coolant system which is used for generation of superheated steam to drive the direct expansion turbine-generator. A schematic flow diagram is shown in Figure 8.

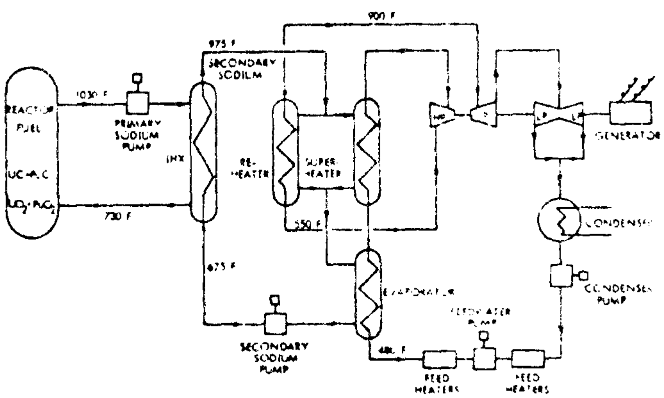


Figure 8 A Typical LMFBR Schematic

Advantages of LMFBR:

1. Relatively mature technology
2. High breeding ratio
3. Excellent heat transfer properties of sodium
4. Its low pressure
5. Assurance that convective sodium cooling will remove fission decay heat under all accident conditions.

Disadvantages: They center on the coolant sodium, i.e.,

1. Its chemical reactivity with air and water
2. Its accumulation of intense radioactivity in the reactor, placing extreme requirements on the leak tightness and integrity of the primary cooling system
3. Its opacity requiring refueling and maintenance to be performed blind
4. Changes in its density causes changes in nuclear reactivity, which may cause control problems in large reactors.

In order for the LMFBR to become a viable source of electric energy, it must demonstrate the capability for safe reliable and economical operation and be acceptable environmentally.

Plant Safety: All nuclear plants are built with safety as the primary design concern. Quality assurance requirements and design standards are unmatched by any other industry. Any radioactive release from an incident must penetrate at least three separate barriers before reaching the external environment; this has a very low probability of occurence. Normal radioactive releases are almost immeasurably low at the plant boundary. A more effective job needs to be done on improving public understanding of the high level of safety designed into nuclear plants, the insignificant level of radioactive emissions and the low risk associated with the handling and storage of radioactive materials and wastes.

Economic Considerations: The factors which determine the economics of any electric generating plant are fuel cycle costs, capital costs, and operating and maintenance costs.

Fuel Cycle Costs: The attractive economic feature of the LMFBR is the low fuel cycle cost. The factors which determine the fuel cycle cost and corresponding estimated values are shown in Table IV.

TABLE IV

	Mills/kwh
Ore	0.0025
Fabrication	0.5
Reprocessing and Recovery	0.2
Plutonium inventory	0.4
Plutonium credit	-0.3
Fuel Cost	0.8*

*Estimated early LMFBR Fuel Cycle Cost (1972$)

In Table IV the uranium ore cost is a small and relatively insensitive part of the total fuel cycle cost. This insensitivity to ore cost does not hold true for LWR's for which the ore cost is approximately 50% of the fuel cycle cost. The fuel cycle cost for the LMFBR is approximately one-half the estimated value for the LWR. This difference in fuel cycle costs allows a significant differential in capital costs - for equal net energy costs. The higher allowable capital costs for the LMFBR (versus LWR) are shown in Figure 9 in $/kwe as a function of year of startup. Also shown are values in current

$ and constant 1972$ for two periods (10 and 30 years) for levelizing the costs.

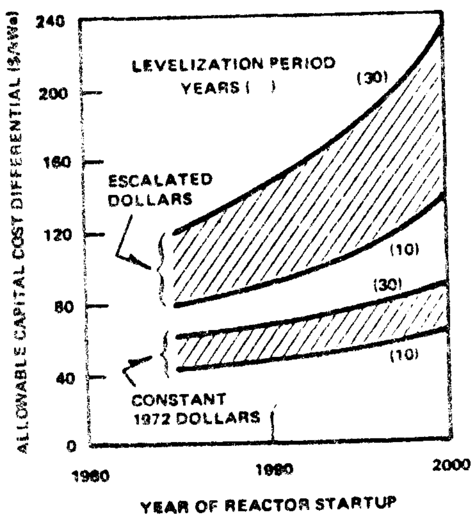


Figure 9 Allowable LMFBR-LWR Capital Cost Differentials

Capital Costs: The capital costs of a coal fired plant are approximately 20% less than the capital costs of a light water reactor plant and the light water reactor plant is approximately 20% less in capital costs than a breeder reactor. The additional capital costs of the water reactor and breeder must be more than offset by lower fuel costs in order to compete with fossil fired plants. Table V shows the fuel cycle cost comparison of a fossil fired plant, a LWR and breeder.

TABLE V

Coal Fired Plant mills/kwh in 1973 dollars [21]

Mining & Transportation	3.2
Sulphur Stack Gas Removal	1.4
Land Reclamation Costs	?
Total	4.6 mills/kwh + ?
LWR	
Mining	0.8
Manufacturing	0.3
Transportation & Processing	0.9
Plutonium Sale	-0.2
Total	1.8 mi-ls/kwh
Breeder	
Mining	negligible
Manufacturing	0.3
Transportation & Processing	0.7
Plutonium Sale	-0.2
Total	0.8 mills/kwh

This substantial fuel cost savings can be realized by using breeder reactor power. To understand what these various costs mean, if all the costs for the different projected power sources were added up to the end of the century and compared with each other, the breeder reactor would be cheaper than the best alternative by from 35 to 45 billion dollars. The country would thus realize a savings in capital cost of from 35 to 45 billion by introducing the breeder reactor into its power network.

With the increasing cost of capital and the difficulties associated with obtaining it this may be a most significant feature.

An illustration of the effects on cost of improved technology and multiple plant sales in a series of steps leading from a demonstration plant technology to a competitive commercial plant is presented in Table VI.

TABLE VI

Cost Effects of Various Levels of LMFBR Design* Reported in [18]

Technology	(1040 MWe Plant)		[Costs in 1972$]
Plant-Related	Plant Cost		Energy Cost
Level of Technology	($\$10^6$)	($/kwe)	(Mills/kwh)
Demonstration Plant Technology (1st of a kind)	889	885	20.5
Target Plant Technology (1st of a kind)	775	745	17.6
Commercial Plant Technology (1st of a kind)	592	569	13.5
Commercial Plant Technology (4th of a kind)	349	335	8.46

Operating and Maintenance Costs: Estimates by General Electric project these costs as being about 0.35 mills/kwh.

Cooling water requirements for the LMFBR's will be less than for LWR's because of higher thermal efficiency approximately 40-42%.

Environmental Effects: Environmental comparisons of one energy source with another should relate to the relative impact of each source on the environment and on individuals in society. Essentially all power plants that are put in operation cause disturbance to the earth form mines required to get the fuel; disturbance to the atmosphere from released pollutants of one form or another; and thermal disturbances to rivers, lakes, oceans, or the atmosphere.

Table VII shows these effects for a 1000 MWe coal fired plant, a LWR, and a breeder reactor power plant. Table VIII compares the annual fuel cycle logistics for a LMFBR, LWR, HTGR, and coal power plant. Table IX shows the fuel consumption (U_3O_8) of a LMFBR, LWR and HTGR.

TABLE VII

Environmental Effects for Different Types of 1000 MWe Power Plants [21]

(Capacity Factor for all Plants 0-8)

	Coal-Fired Plant	Water Reactor	Breeder Reactor
Coal			
Mass, tons/year.	3,000,000	--	--
Volume, cubic feet/year.	120,000,000	--	--
Uranium Ore			
Mass, tons/year as 0.21%.	--	52,000	∿400
Volume, cubic feet/year	--	1,390,000	∿11,000
Gaseous and Liquid Wastes			
CO_2, 10^6 ft^3/day.	53,200	0	0
SO_2, 10^6 ft^3/day.	325	0	0
NO_x, 10^6 ft^3/day.	305	0	0
Particulates, tons/day.	0.4	0	0
Radioactive gases, mrem/year. . . .	Minor Amounts	<5	<5
Solid Wastes			
Collected ash, ft^3/year	7,350,000	0	0
Radioactive wastes, ft^3/year. . . .	0	∿15,000	∿15,000
Thermal Wastes, Thermal Megawatts			
To cooling water.	1,170	1,970	1,170
To atmosphere	400	15	15
Total Thermal Wastes	1,570	1,985	1,185

TABLE VIII

Annual Fuel Cycle Logistics

Fuel Cycle	LMFBR	LWR		HTGR	Coal
Uranium:		Open Cycle	Recycle		
Fuel tons	1.4	200	160	105	-
Ore tons	700	100,000	80,000	52,500	-
Transportation Loads	27	3,800	3,100	2,000	-
Coal:					
Fuel tons	-	73,000	58,000	54,000	2,000,000
Ore tons	-	91,000	73,000	67,000	2,500,000
Transportation Loads	-	910	730	67	25,000

Annual Coal Consumption to operate diffusion plants to supply LWR's & BWR's

TABLE IX

Fuel (U_3O_8) Consumption

	N%	Annual Tons	Lifetime Tons (30 years)
LMFBR	42	1.4	41
LWR-Open Cycle	33	200	5,900
LWR-Recycle	33	160	4,700
HTGR	40	105	31,600

<u>Gas Cooled Fast Breeder Reactor (GCFR)</u>: GCFR research programs were started in 1962 by Gulf General Atomic (now known as General Atomic GA). Since that time studies have included preliminary designs of a reactor experiment, a 300 MWe demonstration plant and a 1000 MWe commercial power plant.

The GCFR concept being developed takes maximum advantage of the helium coolant technology and components developed for the High Temperature Gas Cooled Reactor and of the fuel and physics developmental work being carried out both in the United States and in Europe for the Liquid Metal Fast Breader Reactor. Thus the cost of GCFR development should be considerably less than that usually associated with new reactor concepts. The GCFR provides a second fast breeder reactor approach which results in the additional benefits that accrue from competition between concepts.

In 1968, utility participation was greatly increased with the organization of the GCFR utility program by a number of utility companies and General Atomic. Currently this program is supported by 56 of the United States and 4 European electric utilities, 55 rural electric cooperatives and General Atomic Company.

A summary of GCFR support program is shown in Table X.

TABLE X

Summary of GCFR Support Program

Initiated Participants: 1962-1974	56 Investor owned utilities 2 Public owned utilities 55 Rural electric co-ops 4 European Utilities General Atomic
Dollars Spent	$12 million through FY 1974

U. S. AEC Initiated:

1963	ORNL ANL GA
Dollars spent	$9 million through FY 1974

$ Spent and/or committed to GCFR program by U.S. AEC

(X10^6$)	FY 1968-1972	FY 1973	FY 1974	FY 1975	FY 1976	FY 1977	FY 1978	FY 1979
	1	2	2	7	23	29	33	38

GCFR Demonstration Plant Milestones

Nuclear Steam Supply Design	1970
Preliminary Safety Information Document	1971
Development Program Plan	1972
Balance of Plant Design	1973

GCFR Demonstration Plant Program Costs

(Based on July 1973$ - Millions)

Developmental Program Cost	83
Plant Capital Cost	294
Core Loadings (2 Cores)	54
Post Construction Test Program	10
Total	441

Note: Escalation, interest during construction and owners cost not included.

Cost Comparisons for 330 MWe Fort St. Vrain HTGR and GCFR Demonstration

Plant	FSV (actual)	GCFR (estimated)
Main Circulator	5.3	14.5
Steam Generator	3.5	1.4
PCRV & Internals	4.6	9.5
Control Rod Drives	0.9	2.2
Fuel Handling	1.4	1.2
Other	7.4	8.1
	23.1	36.9

Cost Comparisons in Mills/kwh of LWR's as reported in [78]

GCFR, HTGR & LMFBR (1973$)

	LWR	GCFR	HTGR	LMFBR
Capital Cost	10.0	10.5	10.0	12.5
Operating Cost	1.0	1.0	1.0	1.0
Fuel Cycle	2	0.7	1.8	0.7

The figures above are just shown as a means of comparing various reactor types. In order to find actual costs the current escalation and interest rates have to be taken into account.

Southwestern Public Service Company has recently announced plans to build a 300 to 350 MWe GCFR demonstration plant in their service area in northwest Texas. This plant will be jointly sponsored by Southwest Public Service Co., Atomic Energy Commission, and General Atomics. It is estimated that the construction, development, and testing phase will take approximately 10 years.

Advantages of GCFR:

1. Low capital cost because of design flexibility resulting from single phase coolant and no intermediate loop.
2. Low fuel cycle costs, due to high breeding ratios and low doubling time.
3. Low operation and maintenance cost, since helium is used as the coolant. Helium is a chemically inert, non radioactive transparent coolant thereby permitting direct access to secondary containment.

4. Minimum relation between helium density changes and reactivity.
5. Growth potential due to benefits from carbide fuel and potential for direct gas turbine cycle.

Disadvantages: Heliums poor heat transfer characteristic and low heat capacity require the reactor to be operated at pressures close to 100 atmospheres leaving the fuel liable to overheating, melting and release of fission products in case of rapid loss of coolant pressure.

Operation of GCFR: The flow diagram of the GCFR demonstration plant is shown in Figure 10. The nuclear steam supply system comprises the reactor and three main cooling loops, only one of which is shown in the diagram. Each loop contains a helium circulator, a steam generator and resuperheater. The steam generator produces high pressure (2,900 psi) superheated steam (875°F) that is partially expanded in the turbine that drives the helium circulator. The steam is then reheated to 920°F and sent to the main turbine at 1225 psia. The turbine part of the plant is essentially identical to a conventional fossil fired plant. Figure 11 shows a cutaway view of GCFR NSSS.

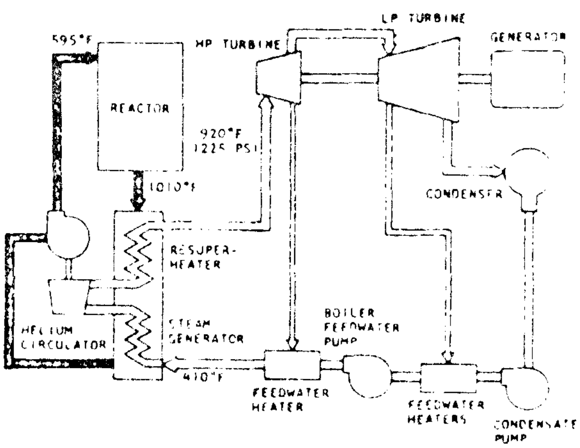


Figure 10 Flow Diagram of 300-MW(e) GCFR Plant

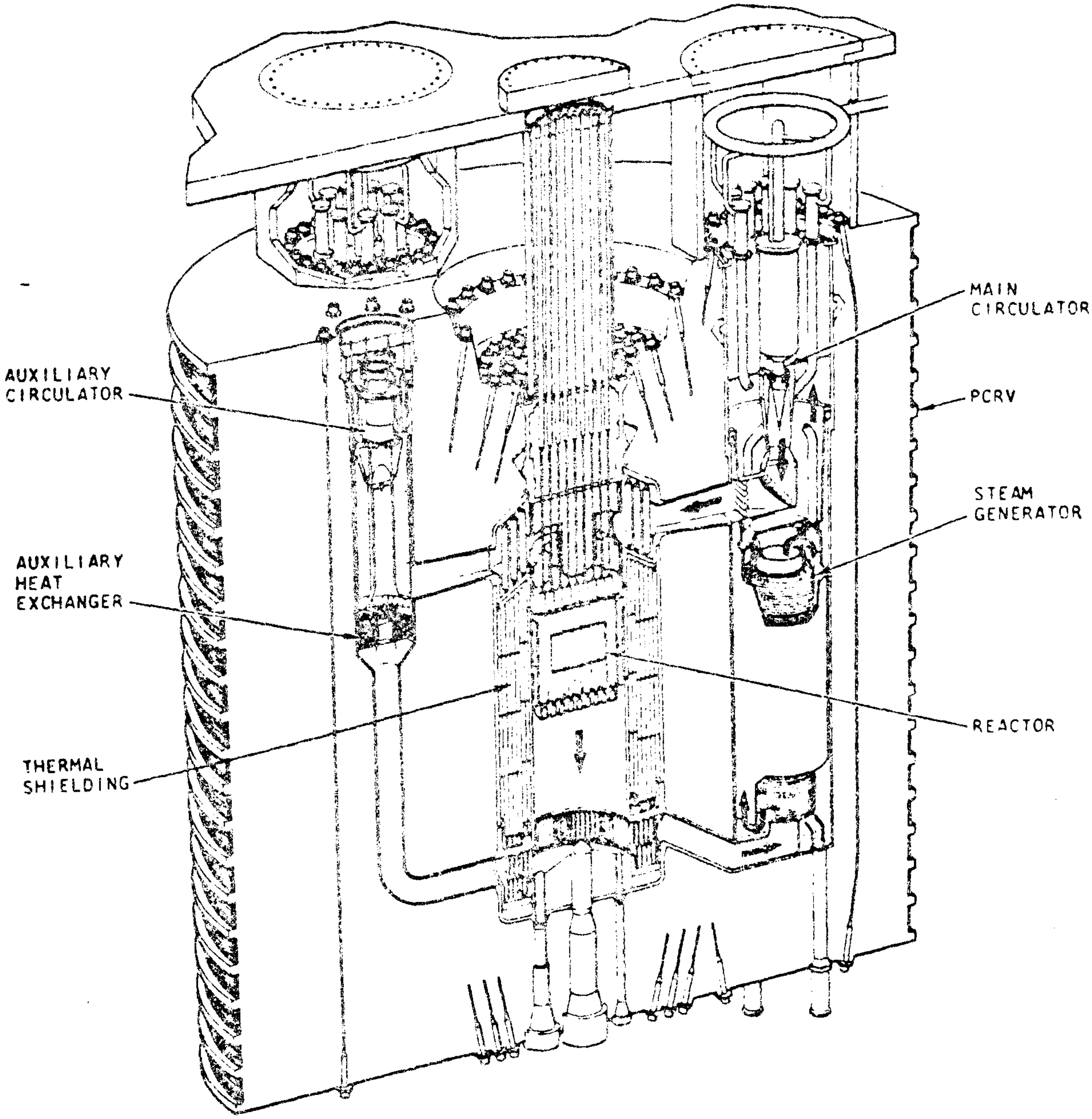


Figure 11 Principal components of the GCFR Nuclear Steam Supply System Within the PCRV

d. Offshore Nuclear Power Plants

An offshore nuclear power plant is a nuclear power plant of standardized design, constructed on a floating platform in a shipyard like manufacturing facility. The completed plant is towed to a site several miles from shore, and permanently moored in a protective breakwater. An under water cable transmits the electric power from the plant to a distribution station on shore for coastal load centers.

Offshore nuclear plants have been developed for the following reasons:

1. Siting at sea provides many additional sites closer to coastal load centers, insulation from seismic shock, an abundance of cooling water, and minimized impact upon the environment.
2. Standardized design and assembly line manufacture will result in simplified licensing procedures, shorter construction time, better quality assurance, and reduced overall cost.

The offshore power plant is a joint Westinghouse-Tenneco project. Both plant and supporting platform will utilize existing proven technology. The plant will have a 1150 MWe net output and will utilize a pressurized water reactor (PWR) nuclear steam supply system.

Applications of Offshore Nuclear Plants: Coastal cities within a 200 mile strip along the Atlantic, Gulf and Pacific coasts represent about 42% of the total U.S. demand for electric energy.

Offshore nuclear plants need only about 70 acres of unused ocean floor, compared to 300 acres or more for a land based plant. There are thousands of suitable sites for floating nuclear plants along the 5,700 mile coastline of the U.S. and these sites will be about 3 miles offshore and thus nearer to coastal load centers than is now possible. For land based generation plants suitable sites are becoming more scarce, more expensive and more distant from load centers.

To date four 1150 MWe offshore nuclear plants have been ordered, by Public Service Electric and Gas Company of New Jersey. They anticipate locating these plants at a site approximately 11 miles NE of Atlantic City, three miles offshore from the Atlantic Ocean coast of New Jersey.

2. Future Nuclear Developments

a. Fusion

Neither the fossil fuels nor the Light water reactors are long-term solutions to the energy requirements of either the United States or the world. Commercialization of the breeder reactor would provide a partial solution but it has certain liabilities i.e., the requirement to transport and process plutonium, the necessity to dispose of high-level radio-active waste, the higher possibilities of escape of radio-active gases to the atmosphere when compared with fusion systems and continuing problem of high levels of heat rejection to the surroundings. The answer to these problems is nuclear fusion if economical processes can be made to work.

Fusion plants will make no use of the world's oxygen or hydrocarbon resources, nor will there be release of noxious combustion products. There will be no runaway accidents, for there is no critical mass required for fusion. The principal reaction products are relatively high energy neutrons, nonradioactive helium and hydrogen nuclei. The element tritium is a problem, but unlike plutonium, tritium is one of the least toxic of radio-active isotopes. Estimates are that tritium will not be a difficult problem to contain and control. The fuel for fusion reactors is deuterium which is easily separated from seawater and thus is in abundant supply and holds the promise of an inexhaustable energy source.

For these reasons research on fusion energy has been going on for a number of years. The research is directed towards finding the means to establish and maintain a low density plasma (10^{14} particles/cc) at a very high temperature ($>10^{8}$c) for a long enough time (on the order 1 sec) to enable a fusion reaction to take place, and to produce energy in excess of that used to attain the temperature and to maintain the confinement of the plasma. To date, both the plasma temperature and the confinement times have been attained but not at the same time nor in the same device.

Currently research on controlled fusion is carried out at several AEC supported laboratories, universities and industrial concerns. Table XI shows some of these R & D efforts.

TABLE XI

Tokamak Systems	
1. Alcator	MIT
2. Tokamak ST	Princeton Plaza Physics Lab
3. Adiabatic Torordial Compressor	"
4. Floating Multipole I	"
5. ORMAK	Oak Ridge National Laboratory
6. Texas Turbulent Tokamak	University of Texas
7. Doublet II	General Atomic
Theta Pinch Systems	
1. Stage Theta Pinch	Los Alamos Scientific Lab.
2. Implosion Heating	"
3. Scyllac IV	"
4. Scyllac Sector	"
Magnetic Mirror Systems	
1. Baseball I	Lawrence Radiation Laboratory
2. Baseball II	"
3. 2 X II	"

There are several varieties of plasma confinement systems but only two kinds, open and closed systems. The closed systems are characterized by the toroids, like the "stellarators" and "Tokamak" systems as shown in Figure 12. The open systems shown in Figure 13 and Figure 14 are characterized by the "theta pinch" and "magnetic mirror" schemes.

Another basic area of fusion research is the laser program. Here, a very short pulse of intense light from a laser is used to heat up the surface of a deuterium-tritium fuel pellet. The surface evaporates very quickly producing an acceleration of the surface material which implodes the pellet to a very high density. The pellet temperature rises as a result of compression and energy from the laser and micro-explosions occur. Energy is trapped in liquid lithium which is also used to capture neutrons and produce tritium.

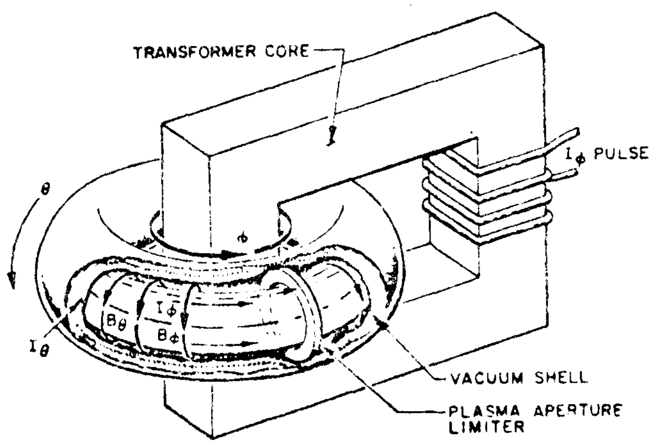


Figure 12 The Tokamak Plasma Confinement Scheme

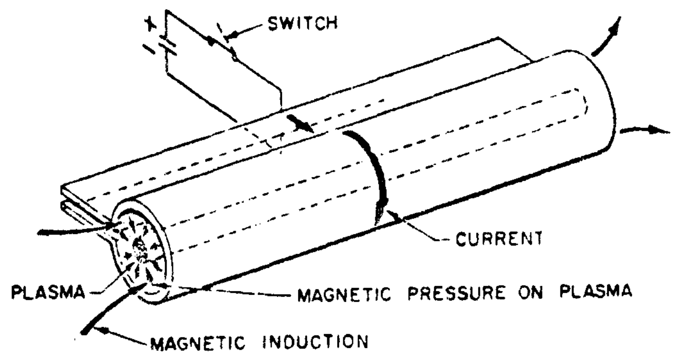


Figure 13 Pulsed Plasma Heating and Confinement Scheme

(so called Θ-pinch)

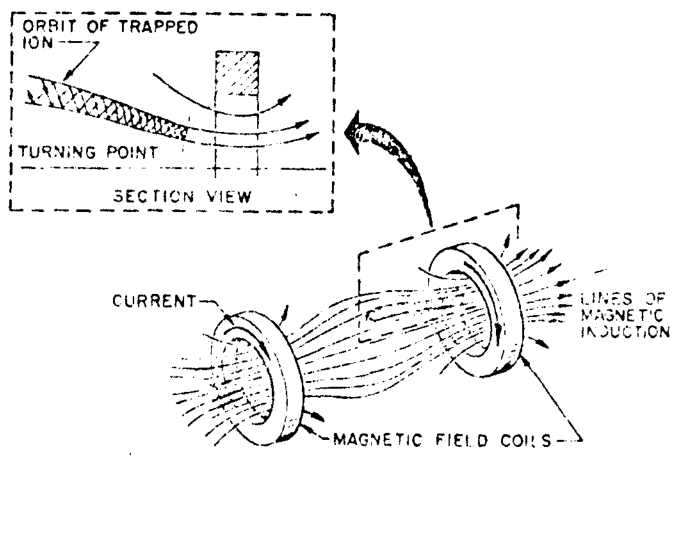


Figure 14 Magnetic Mirror Particle (and Plasma)

Confinement Configuration

Problems with Fusion Development and Future Outlook: Many fusion researchers are of the opinion that there are no theoretical constraints to achieving a fusion reaction. The several difficult problems relating to the instability of the magnetically confined plasma have been solved, and progress has been made in vacuum technology, in cryogenic super conducting magnets, and in materials. Many researchers are of the opinion that controlled reaction would be demonstrated within the next five to ten years, but that there will be no commercial development within the 20th century.

There are significant engineering problems that have to be solved before the advent of a commercial power plant. Most of these problems are not yet clearly perceived and have not received serious and detailed consideration. There are problems with the behavior of structural materials, that become irradiated by the high energy neutrons, problems in the development of lithium blankets for breeding tritium, problems in the development of large superconducting magnets, problems of large high vacuum systems, problems in fueling techniques and problems in heat transfer. These problems need definition and solution before a commercial system can be rationally considered.

In summary, fusion power is in an early stage of research with a great deal of technological development being required before usable electric energy can be produced. This is not likely to occur on an economical basis until after the year 2000.

b. Molten Salt Breeder Reactor (MSBR)

The principal financial support of MSBR development has been provided by the USAEC. A total of $150 million has already been expended with a present annual budget of $5 million. The principal developer of the MSBR technology has been Oak Ridge National Laboratories, which has been conducting work on this concept since the late 1940's. In addition two industrial groups have engaged in limited technology assessment and conceptual design studies of a MSBR.

The major molten salt reactor facility operated thus far is the 75 MWt. MSRE conducted at Oak Ridge National Labs between 1965 to 1969. The MSRE (molten salt reactor experiment) demonstrated some critical features of an MSBR. These include stability of fused fluorides, the simplicity of reactor control and feasibility of operating with highly radioactive circulating fuel.

Major problem areas demonstrated by the MSRE:

1. Cracks in material used to contain fuel salt.
2. Tritium formed from lithium in the reactor fuel was found to diffuse thru the MSRE reactor vessel and heat exchanger.
3. Fuel reprocessing.

The MSBR has lower breeding ratios than competing breeders, so that fuel must be processed continuously at the power plant thus requiring molten salt power generators to meet very stringent siting specifications for fuel reprocessing plant.

The molten salt concept has some notable advantages compared with other reactor types:

1. It promises to make more effective use of thorium than any other reactor concept.
2. Control is simple and reliable because of the large, prompt, negative reactivity temperature coefficient of the fuel.

3. Emergency core cooling can be provided easily and reliably by draining the fuel into a vessel cooled by natural convection.
4. The molten salt fuel requires no fabrication and has been shown not to be subject to radiation damage.

Because of these advantages of the MSBR, it is believed that solutions can be found for the major problem areas. This would require many development projects to be undertaken and completed. This would take many years and hundreds of millions of dollars to bring the MSBR to commercial status. It is not anticipated that this will be achieved until after the year 2000.

3. Technology Assessment of Coal for Electrical Generation

Several factors including the rapidly increasing price of crude oil and worsening shortages of natural gas make coal one of the most likely energy sources for electrical generation between now and the year 2000. The United States has huge reserves of coal with Texas share of these being mainly in the form of lignites. The current and predicted future energy situation in the world indicates that the United States will be forced to make substantial use of these reserves.

There are three broad classifications of means of releasing energy stored in coal. These are (1) direct combustion; (2) coal gasification, (3) coal liquifaction. Each of these classifications may be further divided by several different processes available or under investigation. A technology assessment of these three methods of coal energy production will be presented under three headings: (1) currently available commercial processes; (2) processes with an advanced state of technological development; (3) processes in a research and development phase not expected to be available on a commercial basis in the immediate future (within 20 years).

a. Direct Combustion

Coal has been used in boilers for production of steam in commercial processes for several decades. The largest challenge to using coal in this manner currently is to control emissions to an environmentally acceptable level. These levels are set by the Federal Environmental Protection Agency and concern acceptable concentrations of sulfur dioxide, nitrogen oxides, and particulate matter principally. It is very doubtful that any American coals can be utilized in direct combustion and meet the EPA standards without some form of emissions control. Due to this factor, the emphasis here will be placed upon processes for controlling emissions during direct combustion of coal rather than the technology for combustion itself.

The two areas of greatest concern in emission control are sulfur dioxide and nitrogen oxides. NO_x levels can be reduced to federal levels with currently available boiler design and coal-firing techniques. This is not the case for SO_2 and systems are necessary for removing this pollutant from stack gases after combustion.

Processes which have been investigated for this removal from stack gases may be divided by two broad classifications. The first of these classifications is "throwaway" as opposed to "recovery" processes. The throwaway systems produce an end product waste with no potential value for which disposal must be provided. A recovery process has an end product for which there is a marketable use, with or without treatment.

The second general classification is "wet" and "dry" systems referring to the stack through which final discharge of flue gas is made. A wet stack is chemically resistant and absorbs some of the objectionable pollutants as stack gases leave through the stack. This is performed after the gases have been quenched and scrubbed with a suitable liquid and demisted. Condensation occurs within the stack and a steam plume emerges. The gas leaving the scrubber is reheated in a dry stack system. This raises the gas above its dew point to prevent condensation in the stack since it is not chemically resistant.

Currently Available Commercial Processes: The first commercial process tested on large scale units was limestone injection into the boiler followed by wet scrubbing in the stack. After pilot plant work at Wisconsin Power and Light in 1964 and Detroit Edison in 1966, attempts were made at five installations to use this process:

1. Union Electric Maramec No. 2, 140 MW, 1968
2. Kansas Power and Light Lawrence Station Unit 4, 125 MW, 1968
3. Kansas Power and Light Lawrence Station Unit 5, 430 MW, 1971
4. Kansas City Power and Light Hawthorne Station, Units 3 and 4, 130 MW, 140 MW, 1972.

The injection of limestone into the boiler caused several problems including plugging and scaling in the boiler and mist eliminator plugging. The Meramac Installation has been dismantled due to the plugging that resulted. After extensive modifications, the other units are operating but experiencing problems. It is doubtful that any further installations using this process will be attempted.

To avoid problems inherent in boiler injection, limestone scrubbing has been employed. In this system limestone in the scrubber is relied upon for SO_2 removal. Two Babcock and Wilcox modules were backfitted on Commonwealth Edison's 163 MW Will County Unit No. 1. Plugging of the mist eliminator was the biggest problem with the first module operated. Modifications were made during installation of the second module and the first module was eventually scrapped for use in repairs of the second. Availability of both modules working together, which is necessary for proper operation, was only about 10%.

A similar installation composed of seven modules began operation in 1973 at Kansas City Power and Light's 820 MW La Cygne Station. Again, the mist eliminator has been the main source of problems. Scaling on the scrubber walls and resultant plugging of the perforated plates by this scale has also caused problems.

Arizona Public Service Company started up a limestone wet scrubber at its 115 MW Cholla Station. This unit operated successfully for 21 days before a scheduled shutdown. Due to the experience gained during a successful 500 hour pilot palnt operation, Detroit Edison is also installing a limestone scrubber at its 360 MW St. Clair Unit No. 3.

Another wet scrubbing system makes use of a hydrated lime slurry rather than limestone. Its higher reactivity with SO_2 makes it a more attractive absorbent but this also results in more plugging and scaling. A sludge stabilization system can be installed which may enable the sludge to be used as land fill. Duquesne Light Company and Ohio Edison both have installed this type of system (180 MW and two 825 MW units respectively) shceduled for start up in late 1974. A skid-mounted horizontal scrubber using lime to handle part of the stack gas at Southern California Edison's Mohave Station is reported to be operating well since December 1973.

The only system currently available producing a recoverable product is scrubbing with magnesium oxide followed by production of sulfuric acid. The stack gas, after scrubbing with a slurry of magnesium oxide to form magnesium sulfate, is dried and calcined to drive off the SO_2. This regenerates the M_gO while the SO_2 is used to make weak sulfuric acid. Boston Edison has a 150 MW unit whose major problems have been with caking in the centrifuge and control problems with the dryer. Processing of the magnesium sulfate is subcontracted. Insufficient data is available on how many cycles the M_gO can withstand. Potomac Electric and Power (190 MW) and Philadelphia Electric (120 MW) have installations due to start operations this year with modifications aimed at avoiding Boston Edison's problems.

Processes with Advanced Technology: Wet scrubbers using lime or limestone depend on a slurry of insoluble reactants producing insoluble products which causes the major plugging and scaling problems. One system under investigation is to scrub with a clear liquid which produces soluble products. This requires a step to convert the products to insoluble solids by neutralization with lime for disposal while regenerating the absorbent liquid. This is done by "double alkalai" systems making use of a solution of alkalis such as sodium hydroxide, sodium carbonate, and sodium bicarbonate. This process has been tested at several General Motors power stations and a test unit is being installed by Gulf Power Company. Nevada Power has three 125 MW units using this system under construction.

A similar method uses a weak solution of sulfuric acid as an absorbent since SO_2 is highly soluble in this forming sulfurous acid. This is oxidized by air to sulfuric acid which, while too weak to be useful, can be reacted with pulverized limestone to form gypsum crystals for wallboard production. Several small Japanese plants use this system and a 350 MW oil fired boiler installation is under construction. Gulf Power plans to start up a test unit in the fall of 1974.

A process producing saleable high strength sulfuric acid is catalytic oxidation followed by adsorption in sulfuric acid. The SO_2 is oxidized to sulfur trioxide and then the stack gas is scrubbed with sulfuric acid. The biggest drawback to this system is that high efficiency particulate removal must precede scrubbing. Particulate matter can poison the catalyst or dirty the acid lowering its economic value. Illinois Power Company built a 100 MW demonstration plant partially funded by EPA which is scheduled to begin operation in 1974.

There are several recovery systems being developed which produce elemental sulfur as an end product. A common problem is the requirement for a hydrogen source which must be supplied by a hydrocarbon or steam-coal reaction. One of the most advanced of these systems scrubs with a solution of sodium sulfite and sodium bisulfite. A bleed stream is reheated, releasing the SO_2 and regenerating the liquid. Part of the SO_2 is reduced with hydrogen to form H_2S. This in return reacts with the remaining SO_2 to form sulfur and water. This system has recently been employed on two Japanese oil fired boilers. Northern Indiana Public Service is installing a system partially funded by the EPA on a 100 MW unit scheduled to start up in late 1974.

Another sulfur producing process uses adsorption of SO_2 on CuO forming copper sulfate. This is treated with hydrogen to release the SO_2 and regenerate the copper oxide. Sulfur is formed as in the system just discussed. Demonstration units are in operation in Japan and Tampa Electric Company is building a test unit.

All the discussion of stack gas clean up methods is not meant to imply that this is the only direction that solutions are being sought for using coal in combusion processes. Changes in boiler designs are being made to accomodate clean up systems and to lessen their necessity. The most promising systems in development make use of fluidized coal beds in the boiler. Fluidized beds are made of inert granular particles stocked with a small inventory of coal. Hot gases rising rapidly from below the bed keep the inert particles very hot and agitated, forcing it to behave like a boiling fluid which burns the coal rapidly. Heat absorbing surfaces are located in the bed for high heat transfer rates. Due to this, boiler size and operating temperature can be reduced limiting NO_x emissions. If operating temperature is correctly controlled, SO_2 can be largely removed by reaction with dolomite or limestone which is fed with the coal. This can significantly reduce the reliance upon stack gas cleaning methods with the possibility that stack gas scrubbing may eventually not be required. An experimental boiler using this design has been successfully tested.

Processes in Research and Development Phase: Due to EPA pressure for rapid development of a workable scrubbing system, one of the previously mentioned systems will probably become commercially reliable before any advanced scrubber systems under less intensive research reach testing stages. Therefore no concentrated presentation of systems in an R and D stage will be made here. One process worth mentioning here is ammonia scrubbing followed by reduction to sulfur. Scrubbing with ammonia liquid is very effective for removing SO_2 but has always been associated with a blue plume discharge. A process has been developed to eliminate this blue discharge, so ammonia scrubbing combined with a reduction step to form sulfur is promising.

Fluidized bed combustion continues to show advantages over older boiler designs. A recent improvement is the development of a cell concept for dividing a common furnace bed into separate sections. These divisions allow special purpose burning cells, independent shut-down capability, and rapid start up. Another innovation is supercharged fluid bed combustion. This boiler design would operate at a sufficient pressure rating to enable use of a gas turbine in combined cycle operation.

Another research effort is directed at using coal fired magneto-hydrodynamics. This will provide greatly improved process efficiencies and emissions control. It does not appear, however, that this development will reach a commercial stage within the frame of the study (i.e., prior to the year 2000).

b. Gasification of Coal

An indirect means of using coal for combustion is through gasification to produce synthetic natural gas containing methane. Methane is more suitable for combustion from several environmental viewpoints. There is no particulate matter produced and temperatures are more easily controlled to reduce NO_x levels. In particular, sulfur is present as hydrogen sulfide during gasification and is removed before combustion eliminating SO_2 problems in stack gas. Since many utilities have existing boiler facilities using methane in natural gas for combustion, a process producing a reliable source of methane is attractive.

Gasification involves the combination of coal and water at elevated temperatures to produce carbon monoxide, hydrogen, and methane (CH_4).

The principal reactions involved are:

$$C + H_2O + Heat = CO + H_2$$

$$CO + H_2O = CO_2 + H_2 + Heat$$

$$C + CO_2 + Heat = 2CO$$

$$C + 2H_2 = CH_4 + Heat$$

The initial reaction of coal with water requires heat. Possible sources of this heat are direct combustion, chemical, electrical, and nuclear. Another point about gasification is by-products produced including phenols, naptha, coal tars, light oils and sulfur.

Three possible end products are possible from gasification processes classified according to the BTU content of the synthetic natural gas (SNG) produced. These are (1) low BTU, 100-200 BTU/scf; (2) mid BTU, 300-350 BTU/scf; (3) high BTU, 900-950 BTU/scf. The principal difference between low and mid BTU processes is the use of air rather than pure oxygen during production of heat for the gasification step. Using oxygen results in a lower nitrogen content which increases the BTU rating. High BTU SNG is considered interchangeable with natural gas and is suitable for pipelining. Due to compression costs and the low heating value of low and mid BTU SNG, it is not considered economical to pipeline either of these for any appreciable distances.

All processes under development share a series of basic steps:

1. Receiving and storage of coal;
2. Sizing and processing into a form, such as oil or water slurry, necessary for introduction into the gasification reactor;
3. Gasification at high temperature and pressure forming methane,

carbon monoxide, and hydrogen;

4. Gas scrubbing and cooling;
5. Acid-gas removal and purification to remove carbon dioxide and hydrogen sulfide.

In addition, high BTU processes have a step between 4 and 5 for shift conversion of carbon monoxide to carbon dioxide and generation of more hydrogen. The above process is then followed by two additional steps:

6. Methanation of hydrogen with carbon monoxide to produce additional methane;
7. Compressing and drying to pipeline quality specifications.

High BTU SNG production would seem to be a natural answer to utilities facing fuel scarcity problems, especially those with existing natural gas boiler facilities. Unfortunately, natural gas demand has already far exceeded production and the only prediction for the future is a worsening of this situation. It is generally agreed that by the time SNG becomes available for pipelining, all natural gas will be allocated by federal regulations for residential rather than commercial use. For this reason, more emphasis will be placed on low and mid BTU SNG production in this presentation.

<u>Processes Currently Commercially Available</u>: The most reliable commercial process available today is based upon the Lurgi Pressure Gasification Process developed by Lurgi of Germany. After sizing and processing, the coal is fed through a lock hopper system in the top of the water-jacketed gasifier. A rotating distributor in the top of the vessel evenly distributes the coal feed into the reaction area where it is

dried, devolatized, and gasified. Air or oxygen, and steam enter from the bottom. Part of the coal is burned to provide the necessary heat and the steam provides the water needed for reaction. Coal ash remaining is removed through a rotating grate at the bottom of the vessel. Gasification is carried out at 300-400 psig and 1000-1600°F. The raw gas exits at the top for scrubbing, cooling, and purification.

The Lurgi process when not in conjunction with the methanation step is proved reliable and is in use for SNG production from coal and liquid fuels at several European installations. A gasification plant under construction by El Paso Natural Gas Co. is based on this process. The gasifiers are manufactured in Germany and are limited to 12 feet in diameter for shipping. A plant would require several gasifiers in parallel for large scale production. The fixed bed reactor is suitable only for non-agglomerating coal sized between 1/8 and 2 inches.

The other commercial process is the Koppers-Totzek process of Heinrich Koppers GmbH of Germany. Raw coal is processed in a pulverizer dryer unit to reduce moisture content to 2-10% and to grind to 200 mesh screen size. The pulverized coal is fed through a screw conveyor with a mixing head which mixes oxygen with the coal in correct proportion. Low pressure steam is added to this mixture before introduction to the gasifier. Heat is provided by coal-oxygen burners and gasification takes place at about 3000°F and 1 atmosphere pressure. About half of the ash produced exits as slag through the bottom of the gasifier. The raw gas flows out the top to a waste heat boiler to generate high pressure steam. The rest of the ash is removed from the cooled gas by direct water scrubbing. Removal of the H_2S yields a low

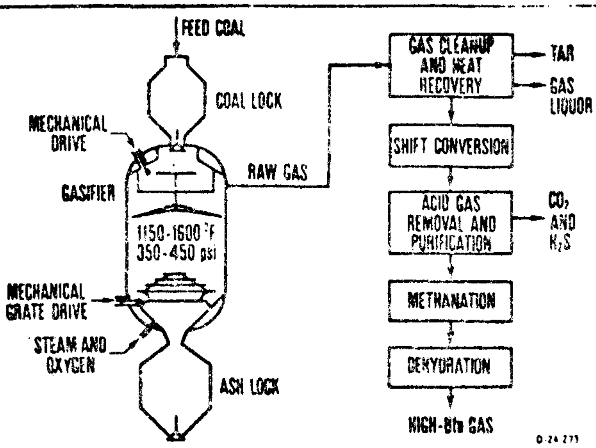
BTU gas for use in electric generating plants.

Since the coal is pulverized and gasified in suspension, the Koppers-Totzek process can make use of any coal. Due to the high temperature in the gasifier, the raw gas is free of condensable hydrocarbon pollutants such as tars, ammonia, and phenols. This high temperature also necessitates a pure oxygen source precluding substitution of air even for low BTU gas production.

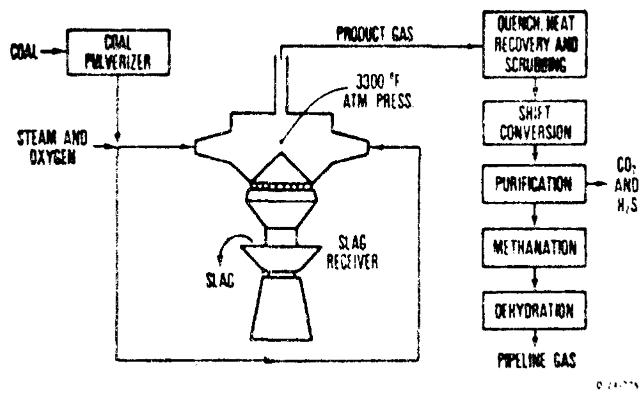
Figure 15 is a schematic flow diagram of all of the coal gasification processes discussed in this report.

Processes with Advanced Technology: In 1971, the American Gas Association and the Office of Coal Research entered into agreement on a $120 million coal gasification project to be funded one-third by AGA. This project is directed toward developing processes for production of pipeline quality SNG to ease the natural gas shortage. All processes will be applicable for low and mid BTU production with less development than that required for production of high BTU gas. This is because the methanation step necessary to upgrade the raw gas to pipeline quality is the least developed and most expensive step in the process. Although there is nothing to prevent utilities from using high BTU processes for production of fuel, economics and development time make low BTU systems much more attractive.

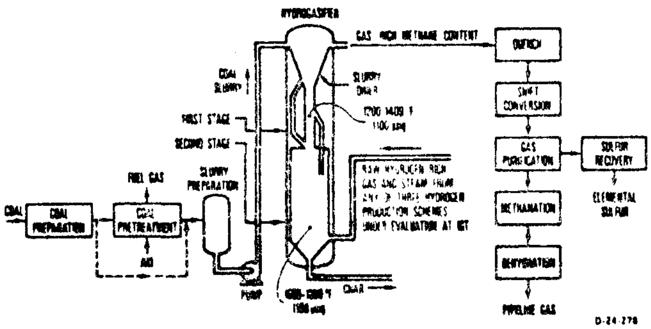
This program has produced development work on three processes. These are (1) BIGAS under Bituminous Coal Research, Inc.; (2) HYGAS by Institute of Gas Technology; and (3) Consolidated Coal Co.'s CO_2 Acceptor Process. The major differences between these processes are gasifier



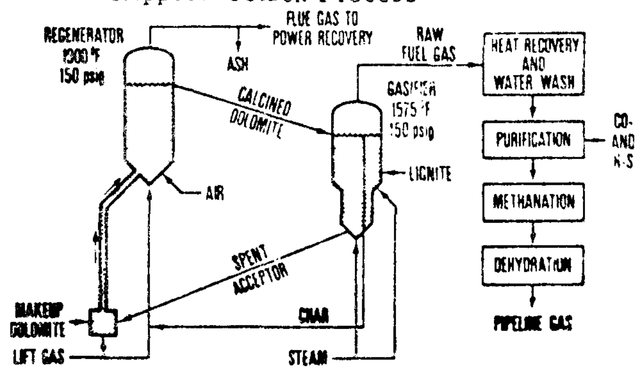
6A. Lurgi Process



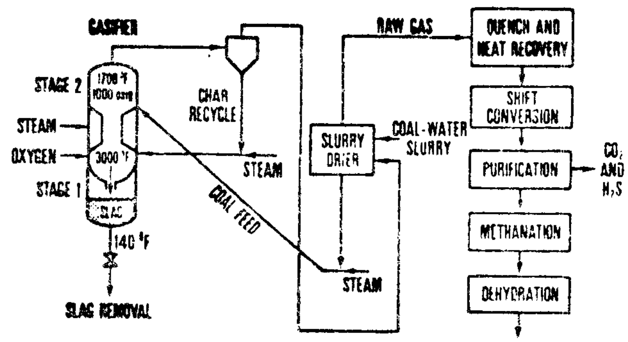
6B. Koppers-Totzek Process



HYGAS Process



CO_2 Acceptor Process



BI-GAS Process Source Ref.[44]

Figure 15

design and heat source for gasification. Although there are several other processes under investigation, only these three will be discussed since their stage of development and level of support make them most likely to reach a commercial stage first.

The BIGAS process makes use of a two stage entrained gasifier. Pulverized coal is introduced into the upper stage where about a third of it is gasified by the synthesis gas rising from the first stage at about 1700°F and 1000 psig. The remaining char is swept into the lower stage where some is burned to produce process heat and the rest is gasified at 3000°F and 1000 psig for entry into the upper stage. Slag is removed through the bottom of the lower stage. The raw gas is then desulfurized by removal of H_2S and cleaned for use in combustion.

The use of entrainment for gasification makes the use of any coal possible. When air is used for combustion, a synthesis gas with a heating value of 175 BTU/scf is produced which is higher than yields from other developing systems. This may enable the BIGAS process to demonstrate most economical operation. A pilot plant is under construction in Homer City, Pennsylvania.

In the HYGAS process, the coal is crushed and sized to -8 mesh size and dried. Agglomerating coals like Eastern bituminous are fed into a pretreater to undergo mild surface oxidation to prevent agglomeration in the gasifier. Nonagglomerating coals such as lignite are sent directly to be slurried with a byproduct aromatic oil and pumped to a pressure of 1100 psig. The slurry is fed to the upper stage of the hydrogasifier where the oil is driven off in a dryer and recovered. The coal is rapidly heated by gases rising from the lower, second stage at 1200-1400°F and 1100 psig. Methane is produced from the volatile matter and rises up through the top of the vessel. Hot char is channeled downward to the fluidized bed in the lower stage. Here it is hydrogasified at 1700-1800°F and 1100 psig through contact with steam and hydrogen. Remaining slag is removed at the bottom and the synthesis gas exits through the top into the upper stage.

Process heat and hydrogen can be provided by three different means. About half of the coal feed is gasified in the hydrogasifier; the remaining char is removed to a steam-oxygen gasifier. Here the char is reacted with steam to produce hydrogen and more synthesis gas which is fed into the bottom stage of the hydrogasifier. The heat for this reaction can be generated by passing direct current between electrodes in the fluidized bed. Remaining char from this gasifier can be removed and burned completely to generate the electricity. Alternatively, a steam-iron reactor can receive the char from the hydrogasifier. Iron is continuously circulated between a fluid bed which reduces iron oxide to iron with a reducing gas and a fluid bed in which iron is oxidized with steam releasing heat and hydrogen. A third means is to feed the char into a reactor for combustion with steam and pure oxygen generating heat and hydrogen.

The HYGAS scheme is further developed than any other in the Office of Coal Research program. Although the steam-iron method for heat generation appears most efficient and economical, the other methods provide the HYGAS system with flexibility. The necessity for a generation of pure hydrogen naturally leads to extra technological problems. The use of several coal beds in the different reactors also leads to control problems. A pilot plant is in operation near Chicago.

The CO_2 Acceptor process makes use of heat from a chemical reaction to produce mid BTU gas without pure oxygen or hydrogen. The ground and dried coal is preheated and fed into a devolatilizer to remove volatile components. It is then fed into the gasifier where it is heated with steam to 1500°F and 150-300 psig. Dolomite at 1900°F from the regenerator is fed into the top of the gasifier. Particles of the dolomite filter down through the gasifier heating the coal. At the same time, a chemical reaction in which the dolomite absorbs CO_2 releasing heat takes place. The used dolomite and char residue are circulated back to the regenerator where the dolomite is regenerated by combustion of the char. The synthesis gas exits through the top into the devolitatilizer for use in devolatilizing incoming coal. The gas then exits the top of this vessel with a heating value of about 350 BTU/scf.

A pilot plant is in operation in Rapid City, South Dakota. Only lignite and subbituminous coal are suitable for use in the CO_2 Acceptor process but this eliminates the need for pretreatment to prevent agglomeration. A mid BTU synthesis gas is produced free of nitrogen and carbon dioxide without the use of hydrogen or oxygen. Large amounts of dolomite are necessary. Good operation depends on careful control of the flows of char and dolomite, and the fluidizing gases between the several vessels under balanced pressure conditions.

Processes in a Research and Development Stage: There are several other processes being developed for gasification that will benefit from advances made in the projects just discussed. Since the basic technology will not differ much, they will not be presented. One gasification system with significantly different technology is to use a nuclear heat source for process heat and steam.

The proposed process would be very similar to the HYGAS process. The biggest difference is that heat for steam production and hydrogen manufacture and process heat for hydrogasification would be provided by a nuclear reactor. This will offer several advantages. Rather than using part of the coal for combustion for process heat, all of it will be reserved for gasification. It would also remove the need for environmental safeguards for coal combustion. Since nuclear fuel would be used as the heat source, the sensitivity of the entire gasification process to coal prices will be reduced. Of course any system of this kind depends on advances made in other gasification designs and nuclear reactor technology.

Investigation is under way on systems to perform the coal-steam and methanation reactions in a single-stage reactor. Catalysts can be employed to promote the reactions. An alkalai is used for the coal-steam reaction catalyst. For the methanation reaction, iron catalysts produce gaseous and liquid hydrocarbons and nickel catalysts produce methane. The significance of this process is that the heat required for the coal-steam reaction would be largely produced by the methanation reaction. This would reduce plant cost significantly since much less fuel will be required. Test units are being studied to determine if a pilot plant is warranted.

An associated process would be involved in underground gasification systems. A coal seam would be prepared for gasification by mechanical or other methods to provide "linking" between coal deposits. A gaseous mixture of nitrogen, oxygen, steam, and carbon dioxide would then be injected into the seam. Combustion and/or chemical reactions then liberates the coal products which are recovered from the seam. This method would have great advantages over gasification plants concerning costs, transportation, and safety. This process is still in experimental stages and is not expected to be commercially viable before 2000.

c. Liquefaction

The Office of Coal Research has also been involved in a number of projects studying processes for the conversion of coal to clean synthetic liquids. Initial studies have indicated that liquefaction may be more economical than gasification. Liquefaction is not a new concept but new interest has been shown in it due to rapidly increasing costs of fuel oil. Several liquefaction projects have as their goal the complete conversion of coal to several useful end products similar to the refining of oil. Rather than an extensive presentation, a review of projects aimed at converting coal to clean synthetic fuel oil will be covered.

Consolidation Coal Co. operated a liquefaction pilot plant at Cresap, West Virginia between 1967 and 1970. A coal extract was produced with a natural solvent with hydrogen donor capacity obtained from hydrogenation of the extract. After being used in the extraction process, the solvent was converted into synthetic crude. The extract was converted to synthetic crude by Hydrogen-Oil hydrocracking at Hydrocarbon Research, Inc. laboratories.

By adjusting operating conditions, this process can be used to maximize production of clean, low-sulfur fuel oil. The plant was only operated using Pittsburgh seam coal so no data on lignite use was collected. A modification of the plant process will be necessary to produce its own hydrogen supply from coal since the original plant depended on natural gas as a source of hydrogen.

The COED project under FMC Corporation at Princeton, New Jersey has studied the use of Colorado and Wyoming coal at its pilot plant. The major fraction of volatile matter of coal is evolved by heating to successively higher temperatures in multistage fluidized beds. Heat for this pyrolysis is obtained by combustion of a part of the remaining char with oxygen in the last stage. The hot gases produced flow countercurrently up through the beds of the other stages to act as the heat supply and fluidizing gas.

The volatiles and vapors produced are collected and condensed. They are converted to synthetic crude in a fixed bed hydrotreater. Hydrogen for this step can be produced from part of the crude or from some of the remaining char. Residual char can be used for power generation or gasified. The plant is being used for continued evaluation of different coals for the process. Indications are that this process would be most valuable in combination with multipurpose gasification and direct energy plants.

A pilot plant to be built at Fort Lewis, Washington, will make use of the Solvent Refined Coal process. Coal is dissolved under hydrogen pressure in a heavy aromatic solvent. Along with small quantities of hydrocarbon gases and light liquids, a heavy organic material called solvent refined coal is produced. It contains a heating value of about 16000 BTU's per pound with .1% ash and less than 1% sulfur. Melting point is about 350°F. The heat content is achieved regardless of the type of coal used.

4. Other Energy Conversion Systems

a. Gas Turbines and Combined Cycles

The basic gas turbine cycle consists of an air compressor, a combustion system, and a turbine. The air is drawn into the compressor and compressed to about 10 atmospheres with its temperature raised to around 600°F. The compressed air then flows into the combustion system where fuel is injected and fired. The resulting hot gases enter the turbine at about 1950°F and develop the power needed to drive the compressor and the generation load. The exhaust gases are then discharged to the atmosphere at about 1,000°F.

The thermal efficiency of the simple-cycle gas turbine has improved substantially. Modern units have efficiencies of about 30% which corresponds to a heat rate of 11,500 BTU per KWh.

In 1964, gas turbine installations on the United States utility system totaled only about 700,000 KW or about 0.3 percent of the total installed capacity in the country. More than 1,300 of these units are now installed on United States utility system, and they have accumulated in excess of 8,000,000 hours of operation. These 33,500 MW of gas turbines represent almost 8 percent of the total Unites States generating capacity. The present use of gas turbines for stationary power plants is confined largely to simple cycle and peaking power application. The excellent reliability record of gas turbines in United States utility applications is also well documented in the EEI Statistical Report.

The simple-cycle gas turbine has inherent characteristics that minimize several environmental problems. First, it uses no cooling water. This makes the gas turbine acceptable for installations at sites close to population and load centers. The fuel requirement is natural gas or liquid hydrocarbon fuels. One good aspect of burning liquid fuels is that they are clean by comparison with most coals and therefore ash and particulate emissions are minimized. The emissions from the gas turbine consists of SO_x, NO_x, ash and particulates. Modern gas turbine combustion systems are virtually smokeless. The gas turbine can meet the most stringent regulation regarding NO_x emissions. Gas turbines are normally provided with inlet and exhaust silencing to minimize external noise.

Regenerative-cycle unit build on the basic simple-cycle unit by placing an air-to-air heat exchanger (regenerator) in the exhaust stack to extract heat from the exhaust gases and "recycle" it in the generating unit. The compressor discharge air is fed through this regenerator prior to combustion, raising the combustor inlet temperature and hence reducing fuel requirements. Overall cycle efficiencies are improved by about 5%, giving typical heat rates of 9,700 BTU per KW.

The installed plant costs of gas turbines are minimized because of the packaged nature of the gas turbine units. The man hours associated with installing gas turbines are minimal. Since construction labor cost is expensive and will continue to rise, gas turbines have an advantage for this cost element. The elapsed time required for installation is short which minimizes interest during construction. Because of their compact nature, gas turbines can be located close to the load, thereby reducing the cost of transmission. The 1980 maintenance costs of a gas turbine in typical utility service might well be between 0.5 and 1.5 mills per KWh, with an average of about 1 mill per KWh.

Advanced developments in gas turbine technology have focussed on increasing turbine inlet temperatures, either by cooling of turbine blades or by developing new materials with improved high temperature properties. Higher turbine temperatures will result in improved cycle efficiency; heat rates of 8500 BTU/kw-hr may be reasonably expected for advanced regenerative turbine units within the next decade.

The single factor presently holding up expanded use of gas turbines for utilities is uncertainty in the availability of gas and oil. Since these devices are suitable for the use of low BTU gas, the development of economical coal gasification will most certainly have a significant impact on gas turbine usage, particularly for peaking. While experimental direct coal-fired units have been built, this process is still far from commercial realization.

<u>Combined Cycles</u>: The combined cycle plant consists of a gas turbine unit whose exhaust gases are fed into a boiler which feeds a steam turbine. The proportions of gas and steam turbine capacity can vary.

There are basically three types of combined cycle systems. They all employ gas turbines and condensing steam turbine generators.

1. The unfired combined cycle is the simplest of all the combined cycle systems. Improvement in efficiency is accomplished by using a waste heat boiler to take advantage of the exhaust high temperature gas discharged from the gas turbine.
2. Supplementary fired heat recovery combined cycle. Thermal efficiency is increased by supplying supplementary firing of the boiler.

3. The boiler in the exhaust fired combined cycle system is pressurized. The operation of the boiler at compressor outlet pressure improves heat transfer conditions resulting in increased cycle efficiency.

Repower: Since combined cycles consist of two related independent power generation systems, repower can be applied. Repower means addition of a gas turbine to an existing steam plant or addition of a steam plant to an existing gas turbine plant to increase capacity and thermal efficiency.

Most commonly employed is the combination of gas turbine and heat recovery boilers with an existing reheat steam system with the heat recovery boiler replacing the existing fired boiler. This arrangement improves the heat rate of the combined system to the range of modern conventional steam plants. Installation cost is minimized.

The factory pre-packaged steam system is designed to extend the useful life of the old plant and increase capacity and thermal efficiency.

Combined cycles have the potential of increaseing thermal efficiency from approximately 40% for conventional plants to around 45%.

There are 24 combined cycle plants now being installed or on order having a total capacity of over 8,300 MW.

1. Environmental Impacts:

   Water Usage - Low heat rejection to the condenser. The cooling water used is about 60% of that required by a conventional plant. The cost of cooling towers will be lower than for comparable conventional units.

Stack Emissions - The combined cycle requires a high quality fuel. Stack emissions meet the environmental demand for SO_2 and NO_x limit.

Particles - Low carboneous material is present in the exhaust gas.

Noise - It can be reduced to desired sound levels with established abatement techniques.

2. Land Use: A plant of around 300 MW may require less than 1000,000 square feet for the plant itself. This is substantially less than the land requirement for an equivalent coal burning unit.
3. Fuel Usage: Requires high quality fuel oil or natural gas.
4. Economic Consideration: The gas turbine can be installed first when it is commercially available. A matching steam turbine could be installed later. Load growth would be met by an additional matching gas turbine. An overall reduction in investment is thereby achieved for a given load growth.

In 1980, the installed cost for the combined cycle is estimated to be $200 per KW. The estimate for 1980 operation and maintenance cost is 0.7 mill per KWh plus $1 per KW-YR.

The capital cost of a combined cycle can be broken down as follows:

Site work and construction	12%
Equipment	62%
Pipe, Insulation, Heating and Ventilation	6%
Electricity	10%
Interest during construction	8%
Engineering	2%
	100%

The features of combined cycles which favor conversion of existing steam plants to combined cycle units are:

1. Economical use of gas or light distillate oil for reduction of air pollution
2. Low Heat rate
3. Economical Utilization of Emergency Power Generation Equipment
4. Fast starting peaking capacity
5. Minimum operating labor requirement
6. Increased capacity without increased thermal pollution
7. Low installed cost and short time span between decision to build and commercial operation
8. Saving in fixed charges by phased installation of the two cycles
9. Minimal cooling requirements
10. Flexibility of operation

Future Prospects: The combined cycle would play a relatively important position in power generation to the year 2000 if coal could be used as a fuel. This cycle will be particularly significant for peaking and intermediate power generation. The combined cycle requires clean fuel such as oil or natural gas. The coal gasification process can convert coal that is considered to be dirty fuel.

Westinghouse sees coal gasification as the ultimate answer to providing fuel for the gas turbine combined cycle. In 1972, Westinghouse proposed a combined cycle plant coupled with an on-site fluidized bed coal gasifier.

Gilbert Associates proposed that eight months of modest development would lead to a design of 150 MW commercial coal-gas power combined cycle plant.

General Electric has under development a plant using Lurgi gasifiers that should be commercially avialable before 1977.

The Office of Coal Research is aiming at a low BTU gasification program which includes a combined cycle development program as part of its overall objective.

A commercial plant based on the Lurgi process and equipment to manufacture 250 x 10^6 cu. ft./day of low BTU gas has been proposed by the El Paso Natural Gas Company.

In the process of low-BTU gasification, NO_x emissions are significantly reduced. Sulfur and ash are also removed from the coal in the process of coal gasification. The emission of sulfur dioxide is greatly reduced.

Coal gasification is going to be built with the combined cycle as one unit in a combined cycle system in which all the gas produced by the gasifier is burned in the gas turbine. The steam generated by a heat recovery boiler is used as a gasification agent. This system is expected to require the minimum modification of current gas turbines for adapting the gasifier to burn the low BTU fuel.

Improvement of Gas Turbine Combined Cycles: The efficiency of combined cycles will definitely increase, if the size and design of available gas turbines is improved.

Present gas turbine capacities range from 20 to 75 MW. Active design work has been done in improving the size of the gas turbine to boost output from 80 to 100 MW. When these units are commercially available and combined with available steam turbines they will yield capacities of combined cycle systems in the 150-500 MW range, which is a more desirable size range.

If the inlet temperature of gas turbine could be raised, its thermal efficiency would be directly increased. The Advanced Research Projects Agency of DOD is supporting research on improved materials to raise the inlet temperature of gas turbines to 3000°F.

To increase the size of the units and the turbine inlet temperature, further research and development is required on materials, heat transfer, fluid mechanics, and combustion processes.

Summary: Combined cycles, with all their advantages and available technology seem to be a highly probably means for generating electricity especially for peaking and intermediate loads to the year 2000.

The commercial unavailability of coal gasification still causes some uncertainties about fuel supplies. However, the outlook for coal gasification is optimistic. The efficiencies attained with combined cycles are the best of any commercial power generating source. Economically, they are attractive. The impact of combined cycle plants on the environment is acceptable especially in the area of cooling water usage.

Comparison:

	Fossil Steam	Combined Cycle	Simple-Cycle gas turbine
1980 plant cost ($/KW)	400	200	120
1980 fuel cost ($/MBTU)	0.60	1.20	1.20
Efficiency	40%	40-45%	30%
Forced outage rate (%)	5	4	5

Characteristics of Simple-Cycle Gas Turbines

1980 plant cost	$120/KW
1980 fuel cost	$1.20/mBTU
Heat rate (HHV)	11,500 BTU/KWh
Availability	93%
Forced outage rate	5%
Scheduled outage time	2%
1980 operational and maintenance cost	1 mill/KWh
Environmental aspects	SO_x, NO_x, Particulates, Sound

Characteristics of the Regenerative-Cycle Gas Turbine

1980 plant cost	$155/KW
1980 fuel cost	$1.20/mBTU
Heat rate (HHV)	9,700 BTU/KWh
Availability	93%
Forced outage rate	5%
Scheduled outage time	2%
1980 operational and maintenance cost	1 mill/KWh
Environmental aspects	SO_x, NO_x, Particulates, Sound

Characteristics of Combined-Cycle Plants

1980 plant cost	$200/KW
1980 fuel cost	$1.20/mBTU
Heat rate (HHV)	8,050 BTU/KWh
Availability	93%
Forced outage rate	4%
Scheduled outage rate	3%
1980 operational and maintenance cost	$1.25/KW-yr plus 0.7 mills/KWh
Environmental aspects	Cooling water, SO_x, NO_x, Particulates, Sound

b. Fuel Cells

Principle of Operation: A fuel cell is a device in which two chemical constituents, a fuel and an oxidizer, are combined electrochemically to produce electricity directly. A chemical reaction between any two substances involves an exchange of electrons between atoms. In a conventional combustion power plant, the fuel and oxidizer are mixed and the electron exchange occurs directly in the process of combustion, releasing heat which can then be used in a thermal cycle to produce electricity. In a fuel cell, the fuel and oxidizer are not mixed, but are kept separated through a set of electrodes and an electrolyte, as shown in Figure 16.

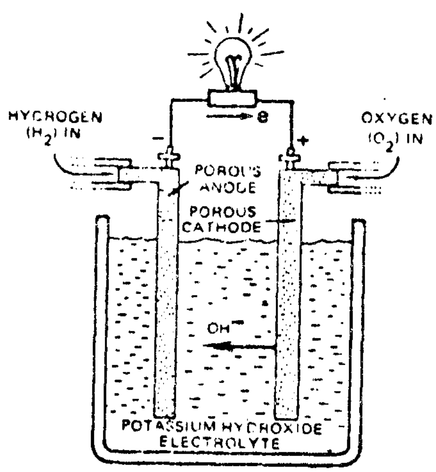


Figure 16

Representation of a Simple Fuel Cell

Electron transfer takes place through the intermediary action of the electrolyte, which serves as a carrier of charges, and electrons are returned through an external load, indicated schematically by the light bulb. Ideally, the electrodes and electrolyte do not themselves undergo any consumptive chemical reactions (as opposed to, say, a common flashlight battery), but rather serve simply as "agents" to assist in the reaction of the fuel and oxidizer; in principle, so long as fuel and oxidizer are continuously supplied, the fuel cell will continue to drive an electrical current through the load. Because of their close family relationship to the common electrical cell and the storage battery, both of which are also simple electrochemical reactors, fuel cell assemblies are often called "fuel batteries".

In practice, fuel cell electrodes take the form of thin, porous, electrically conducting plates which have been coated with a catalyst, usually platinum or nickel, and arranged in a sandwich with electrolyte in the interelectrode spaces. (Figure 17)

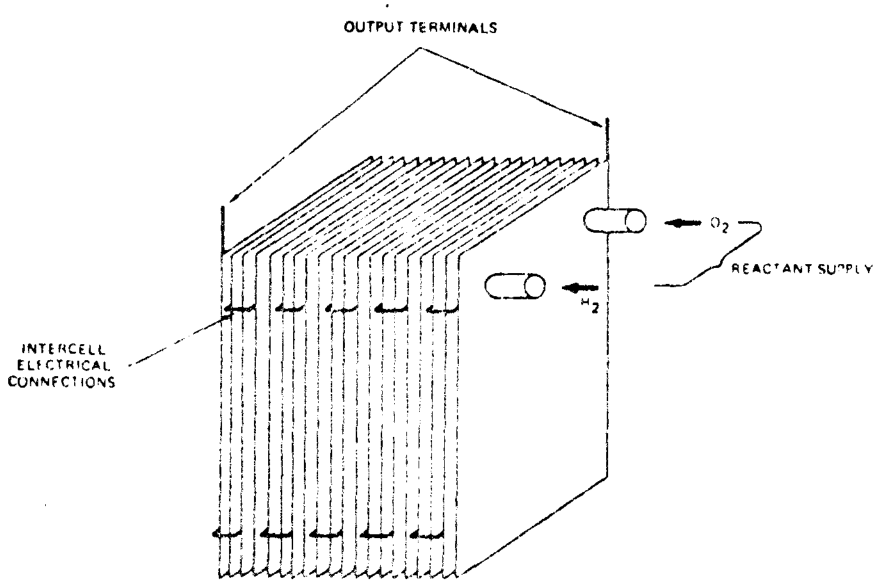


Figure 17 Individual Fuel Cells Assembled into a Compact Stack or Fuel Battery

The electrolyte may be a strong acid or basic aqueous solution, a molten salt, or a solid. Several pairs of electrodes are generally connected in series to give a desired output voltage, and whole "stacks" may be connected in series or parallel to meet the particular requirements of the given load. Means must be provided for removing the product of the fuel-oxidizer reaction (e.g. water in the case of a hydrogen-oxygen cell) and for maintaining the proper flow rates, pressures, and temperatures in the various parts of the cell.

Fuel Cell Systems: For commercial application as an electric power source, two subsystems are required in addition to the fuel cell stacks themselves (Figure 18).

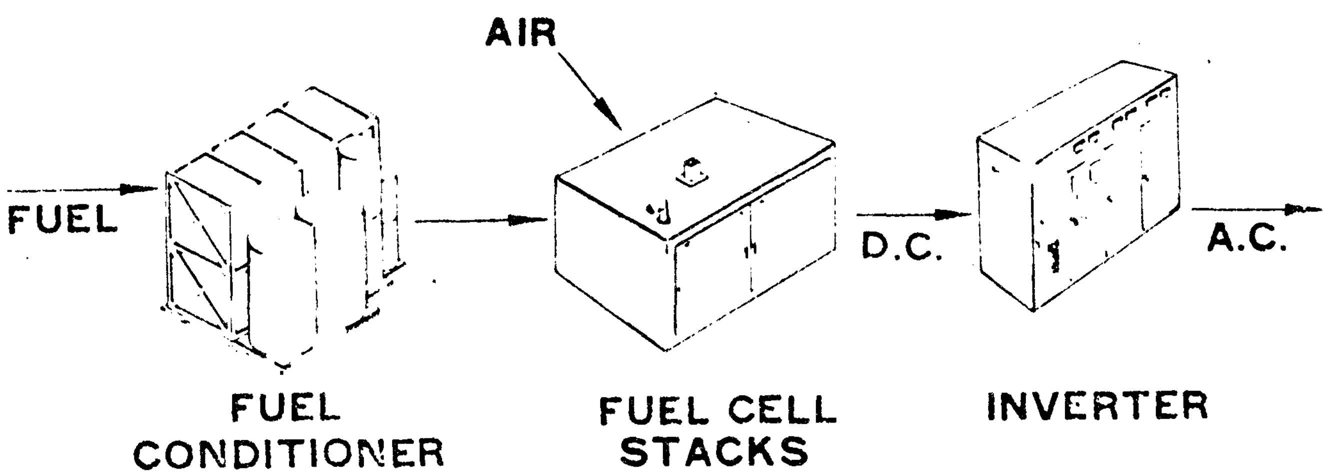


Figure 18

Fuel Cell Powerplant Subsystems

A fuel conditioner unit takes a common commercially avialable fuel, such as natural gas, removes constituents such as sulphur and elemental carbon which might damage the electrodes, and chemically converts the fuel to a hydrogen-rich gas stream suitable for use in the cell. While experimental cells have been developed which directly utilize gaseous or liquid hydrocarbons (methane or methanol in particular), all units presently under development for commercial application are basically hydrogen-oxygen cells preceded by a fuel conditioner.

Since the fuel cell stack produces direct-current, the cell output must be processed by an inverter to convert to A.C. compatible with standard electrical equipment.

Technical Advantages and Disadvantages of Fuel Cells: Fuel cells are an attractive source of electric power from several standpoints. First is the inherent efficiency advantage of a direct convertor over a conventional thermal energy convertor (Figure 19).

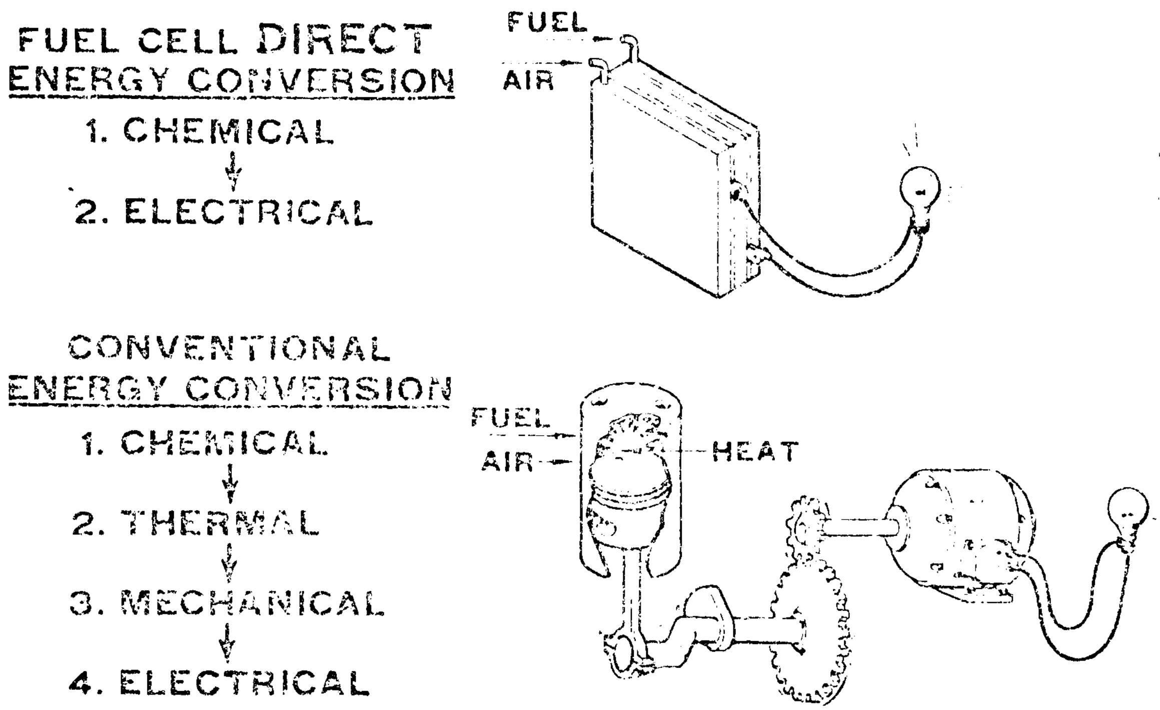


Figure 19 Energy Conversion

In a conventional system, chemical energy is first transformed into thermal energy by chemical combustion. This thermal energy must be converted into the mechanical energy of a rotating shaft, which is then converted to electrical energy in a generator. Each of these intermediate steps, and particularly the thermal-to-mechanical step, reduces the overall efficiency of the process. In the fuel cell, chemical energy is transformed directly into electrical energy, and most importantly, the low efficiency thermal-to-mechanical process is eliminated. Hence theoretical efficiencies approaching 100% are possible in fuel cells, whereas conventional systems are limited by the laws of thermodynamics to theoretical efficiencies of about 60%. In practice, modern conventional convertors can attain about 40 to 45% efficiency, while practical efficiencies in excess of 50% have already been attained with hydrogen fuel cell systems.[11] With hydrocarbon fuels, overall efficiencies of present first-generation fuel cell systems are comparable to conventional convertors. Equally important is the fact that fuel cells maintain this high level of efficiency over a broad range of operating conditions. For example, a typical fuel cell powerplant will maintain nearly constant efficiency from about 25% to 125% of the nominal plant output rating, while gas turbines drop to about half their full power efficiency at only 80% of rated output. [39] Fuel cell systems may be brought on-line within seconds and can respond essentially instantaneously to load changes. These factors make the fuel cell look particularly attractive for "load following", i.e. for providing peaking capability.

Environmentally, fuel cells represent one of the "cleanest" of all power sources. Table XII shows emissions from an experimental 10 KWe fuel cell unit compared with emissions for the same electric energy production in modern conventional central station plants. [34] The fuel cell is clearly superior. Heat from the fuel cell unit is dispersed directly to the atmosphere, and since the only moving parts are small fans and pumps, noise leves are very low.

A principal disadvantage of fuel cells from the technical standpoint is their sensitivity to fuel composition. Sulphur and elemental carbon in the fuel stream can quickly poison the catalyst and block the electrode pores. Direct use of coal without conversion to liquid or gaseous form is presently infeasible.

TABEL XII

MINIMUM POLLUTION CONTRIBUTION

POUNDS OF POLLUTANTS PER THOUSAND KW-HR

	FEDERAL STANDARDS*			
	GAS-FIRED UTILITY CENTRAL STATION	OIL-FIRED UTILITY CENTRAL STATION	COAL-FIRED UTILITY CENTRAL STATION	EXPERIMENTAL FUEL CELLS
SO_2	NO REQUIREMENT	7.36	10.90	0-0.00026
NO_x	1.96	2.76	6.36	0.139-0.236
HYDROCARBONS	NO REQUIREMENT	NO REQUIREMENT	NO REQUIREMENT	0.225-0.031
PARTICULATES	0.98	0.92	0.91	0.00003-0

*FEDERAL STANDARD (EFFECTIVE 8-17-71) VALUES CONVERTED TO LB/1000 KW-HR

As current density in the cell increases, losses also increase, a factor tending to limit the compactness of fuel cell units. Precious metal catalysts presently in use are extremely expensive and their supply might be a serious obstacle to large scale production. As mentioned earlier while conventional systems produce A.C. directly, fuel cells are basically D.C. devices, and invertors are required to produce the desired output.

All of these obstacles can be overcome from a strictly technical standpoint. The crucial question is whether fuel cells can compete economically with conventional systems. This subject is addressed in the following section.

Economics of Fuel Cells: Unlike conventional combustion or nuclear systems, fuel cells do not exhibit significant economy of scale. Because fuel cell systems are inherently modularized, both capital and operating costs on a per kilowatt basis are essentially constant for plant sizes from 1 to 1000 megawatts [27]. Because small plants can be built as economically as large ones, considerable attention has been given to the potential for decentralized fuel cell generation, i.e. the placement of relatively small plants at substations with the attendant saving in transmission costs.

TABLE XIII

1980 GENERATION COSTS: NUCLEAR VS. FUEL CELL Source Ref. 5

	Nuclear Power Plant		Fuel Cell-Mine Mouth				Fuel Cell-Dispersed	
	Public	Investor	Public		Ivestor		Public	Investor
			500 Miles	1000 Miles	500 Miles	1000 Miles		
1. Annual Cost of Capital	6.5 mills	9.0 mills	3.9 mills	3.9 mills	5.4 mills	5.4 mills	3.2 mills	4.3 mills
2. Fuel Cost	2.3	2.3	1.8	1.8	1.8	1.8	3.3	3.3
3. M&O and Insurance	.6	.6	1.5	1.5	1.5	1.5	1.5	1.5
4. Transmission Cost	.6	1.0	1.0	2.0	1.3	2.6	---	---
Delivery Cost	10.0	12.9	8.2	9.2	10.0	11.3	8.0	9.1
Breakeven Fuel Costs at 60% Efficiency	---	---	61¢/10^6	46¢/10^6	83¢/10^6	60¢/10^6	93¢/10^6	125¢/10^6
Breakeven Fuel Costs at 50% Efficiency	---	---	51¢/10^6	38¢/10^6	69¢/10^6	50¢/10^6	78¢/10^6	102¢/10^6

ASSUMPTIONS

Nuclear Power Plant: 1000 MW; $450/KW including cooling towers; $40/KW for transmission.

Fuel Cell Power Plant: 1000 MW, mine mouth at $250/KW and 100 MW dispersed units gas-fired at $200/KW. HV transmission at $200,000/mile. Coal cost: 30¢/10^6 BTU; gas cost, 60¢/10^6BTU.

Financing: Public Power, 10% nuclear, 11% fuel cell; Investor Owned, 14% nuclear, 15% fuel cell.

Table XIII shows a comparison of estimated 1980 generation costs for base load generation with nuclear, fuel cells at the mine-mouth, and fuel cells dispersed at points of distribution, as projected by Pratt and Whitney. These figures are based on an installed cost of \$200-250/KW for the fuel cell; the estimated cost of such a plant based on present-day technology is estimated to be about \$350/KW. It will be noted that for fuel cells at the mine mouth to compete, fuel costs in the range of roughly 40 to 70¢/MBTU would be necessary. If dispersed generation is used, the reduced transmission cost permits breakeven fuel costs on the order of 80¢ to \$1.20/MBTU. With current trands in fuel prices, one may conclude that, even based on these optomistic figures, fuel cells will only be competitive for base load generation if dispersed generation is implemented and if installed costs can be reduced by about 35%.

Northeast Utilities has carried out an unpublished proprietary study of dispersed peaking generation comparing fuel cells with centrally located gas turbines. The study showed that dispersed fuel cells gave slightly lower production costs than gas turbines, the difference being attributable to reduced transmission losses. Assuming 1980 gas turbine installed costs to be about \$120/KW, fuel cells would have to be available at 150 to \$180/KW installed to be competitive if fuel costs range from 80¢ to \$1.20/MBTU.

<u>Fuel Cell Development Programs</u>: Fuel cells were first conceived for domestic electric power in the 1890's and this application provided the principal motivation for their development up to about 1950. In 1932, Francis T. Bacon of Cambridge University began a development program

which was to form the foundation for the explosive growth of fuel cell technology in the 1960's. By 1950, Bacon had demonstrated a 5 KW hydrogen-oxygen fuel cell system using nickel catalyst on porous electrodes. Between 1959 and 1963, Allis-Chalmers had built several demonstration models of the so-called "Bacon cell" for domestic applications.

The space program of the '60's provided the major impetus to practical application of fuel cells. Two significantly different types of H_2-O_2 systems were developed for the Gemini and Apollo programs, respectively.

The Gemini fuel cell, developed by General Electric Company, utilized a solid electrolyte known as an ion exchange membrane. The cell produced an average of 620 watts and flew successfully on seven manned missions for a total of 840 operating hours.

The Apollo fuel cell, developed by Pratt and Whitney Aircraft, used a highly concentrated potassium hydroxide electrolyte which was liquid at operating temperature. Each cell produced up to 1420 watts, and three were used in parallel on each Apollo spacecraft, with no malfunctions occuring throughout the program.

A number of other small scale fuel cell development programs have also been in operation for several years, with applications primarily aimed at military, vehicular, and biomedical applications.

The major thrust of activity for domestic power has been at the Pratt and Whitney Division of United Aircraft Corporation. In 1967, Pratt and Whitney was selected by a consortium of gas utility companies as the prime contractor for a project called TARGET (Team to Advance

Research for Gas Energy Transformation). For this program, sixty 12.5 Kw natural gas-fueled fuel cells (designated PC-11) each about the size of a household furnace, were built and tested in the field for several years. The PC-11 program has successfully demonstrated the reliability and environmental and social acceptability of on-site fuel cell power. Phase III, now in progress, will attempt to assess the commercial viability of second generation systems of the same size.

In the fall of 1973, Pratt and Whitney announced the initiation of a $42 million program to develop a 26 Mw fuel cell for utility applications. $28 million is being put up by a consortium of nine electric utility companies, with the remaining $14 million being provided by Pratt and Whitney. First delivery is scheduled for 1978, and cost of the first demonstration unit is estimated at $270/Kw. This unit is of a size which should be attractive for dispersed generation and for replacement of gas turbines, if costs can be reduced to make them economically competitive.

Federal funding of $80 million for fuel cell development has been proposed for the period 1975-1980 [41]. These funds will contribute substantially to advanced technology and demonstration plant development, though the program is small in comparison with other federal programs for advanced technology (e.g. $315 million for high temperature gas turbines, $200 million for solar, and $2844 million for breeders.)

<u>Advanced Fuel Cell Concepts</u>: Hydrogen is truly the ideal fuel for use in fuel cells, and in fact, most systems which use hydrocarbons simply "fracture" out the hydrogen and then use it in the cell. Hydrogen is clean and abundant. Its high energy content per unit mass makes it particularly attractive from the standpoint of transportation.

A great deal of attention has been payed in recent years to the concept of mass-producing hydrogen and oxygen by the decomposition of water at some central location and transporting the hydrogen in pipelines to dispersed sites [25]. This may be a particularly effective way to utilize nuclear power, since the nuclear unit could be very large (and hence economical) and could run at a steady power level at all times. If the hydrogen economy becomes a reality, clearly the concept of dispersed power generation with fuel cells will be an economically attractive one.

Regenerative fuel cells: Regenerative fuel cells utilize fuels whose reaction product can by "recycled" back into fuel and oxidizer for reuse in the cell. For example, water can be "thermally split" into hydrogen and oxygen at elevated temperature and pressure. A nuclear reactor might be utilized as a heat source for thermal production of hydrogen, which could then be converted to electricity in a fuel cell. The water produced in the cell would be sent back to the reactor, forming a closed-loop system.

Alternatively, the fuel cell might be used in reverse during off-peak periods to electrolyze water, permitting a nuclear plant to operate at steady load. In this case, the fuel cell is an energy storage device for peaking at high load times.

While bench-scale regenerative cells have been built and tested for aerospace applications, no large scale units are under development.

<u>Outlook for Commercial Utilization</u>: As pointed out in the section on Fuel Cell Development Programs, commercial demonstration of a fuel cell in utility service is expected before 1980. Clearly, the level of commitment of the utilities and manufacturer involved in this project indicates their optimism for the future of fuel cells. With the cost of this first generation system estimated at $270/Kw, it is entirely plausible that large scale production could bring the cost down to the $150-$180/Kw needed to make fuel cells economically competitive for peaking service by 1985.

For base load generation, the picture is somewhat less attractive, particularly in view of present trends in fuel cost and availability. In the long term, hydrogen generated by large central nuclear plants and delivered by pipeline to fuel cells on-site or dispersed in substations may prove feasible. To the year 2000, it is probable that nuclear and coal-fired generation will have an economic edge over fuel cells for base loading.

Any projection of the outlook for fuel cells must be predicated on assumed fuel costs, and the present uncertainty as to the price of petroleum and natural gas makes such projections hazardous at best. The development of coal gasification, however, appears to be following a timetable comparable to that of fuel cells, and the price range of 80¢ to $1.20/MBTU on which most fuel cell projections are based is consistent with anticipated prices for coal gas.

c. Magnetohydrodynamics

Principle of Operation: Magnetohydrodynamic (MHD) generators, while usually considered to be direct energy conversion devices, are, in principle, closely related to conventional electric generators (Figure 20).

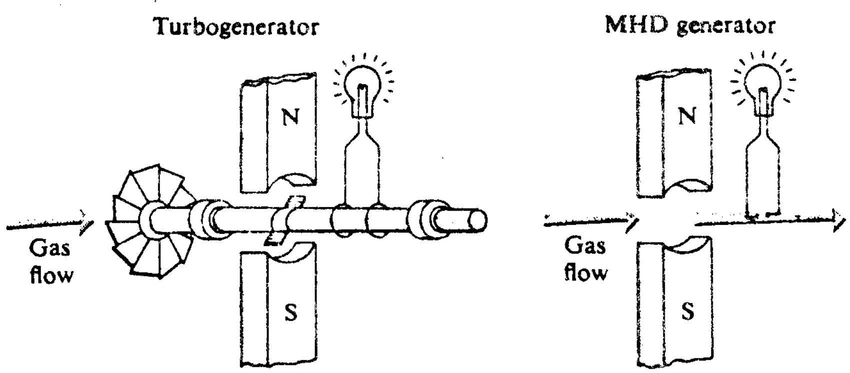


Figure 20

Principle of MHD Generator

In a conventional generator, an electrical conductor (usually a copper wire) is moved in a magnetic field such that the conducting element cuts across magnetic lines of force, thereby generating in the wire an electric current which is carried out to the load. The motion of the copper coil is typically produced by attaching it to a rotating turbine, which is spun by a high velocity jet of steam or hot combustion gas. In an MHD generator the object is also to move a conductor across a magnetic field, but in this case the mechanical turbine and generator are eliminated and the hot gas itself is the electrical conductor. The generator channel has electrodes attached to the side walls, and the current generated by the flowing gas passes through these electrodes to the load. Thus an MHD generator contains no mechanical moving parts.

In a combustion-fired MHD generator, typical gas temperatures in the channel may exceed 2500°K; in order to achieve a sufficiently high electrical conductivity of the working gas, a small amount of alkali metal "seed" (usually cesium, potassium, or rubidium) is added. Alkali metals are easily ionized, and electrons donated by the seed material form the primary carriers of the electrical current. In nuclear powered systems, lower gas temperatures (below about 1100°K) are necessary because of limitations on the reactor core. In order to achieve satisfactory conductivities, the phenomenon of nonequilibrium ionization must be used. In this concept, the generator is operated in such a way that the free electrons are energized to a much high average energy than the bulk of the gas. The "electron temperature" may be four to five times the gas temperature (which is the temperature felt by the generator walls), producing electrical conductivities comparable to those in combustion systems [67].

MHD generators can only operate if the gas temperature is high enough to give significant ionization, and thus the gas leaving the generator channel still has considerable usable energy. For this reason, MHD is considered primarily as a topping cycle to be used in conjunction with conventional lower temperature steam systems. This configuration will be discussed further in the following section.

MHD Power Systems: The MHD channel itself represents only one component of the complete power generating system. In considering the overall picture, it is necessary to distinguish between open cycle and closed cycle systems.

Open cycle systems use air as the primary working gas and are the type considered for combustion of fossil fuels. Figure 21 shows a schematic diagram of such a system.

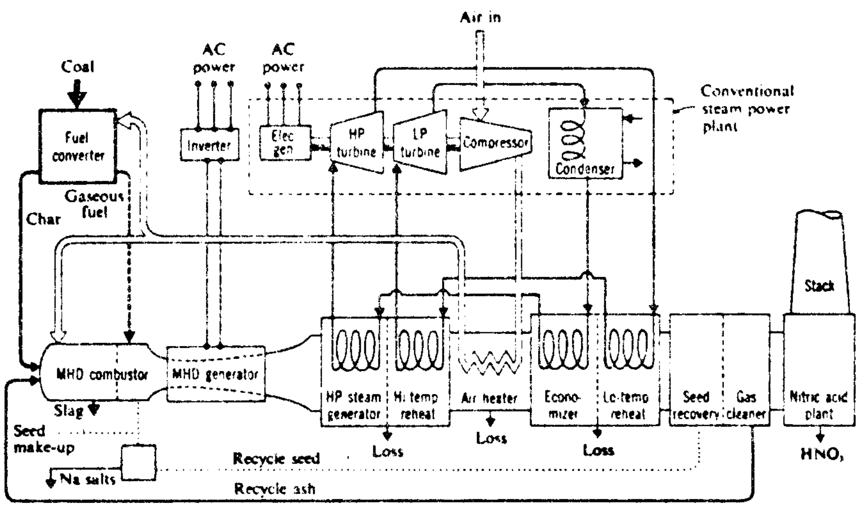


Figure 21

Open Cycle MHD - Steam Combined System

The MHD section includes a fuel convertor to prepare the fuel for proper combustion, the generator channel, an invertor for conversion of the D.C. output of the generator to A.C., a seed recovery system, and an air preheater. In the duct downstream of the MHD section is a steam generating system which feeds a conventional steam turbine-generator, and the stack gas clean-up device. The system is characterized as open-cycle because air is taken in and rejected back to the atmosphere, rather than being continuously recirculated internally.

Closed cycle systems use a gas such as helium or argon which is continuously recirculated in the system, as shown in Figure 22.

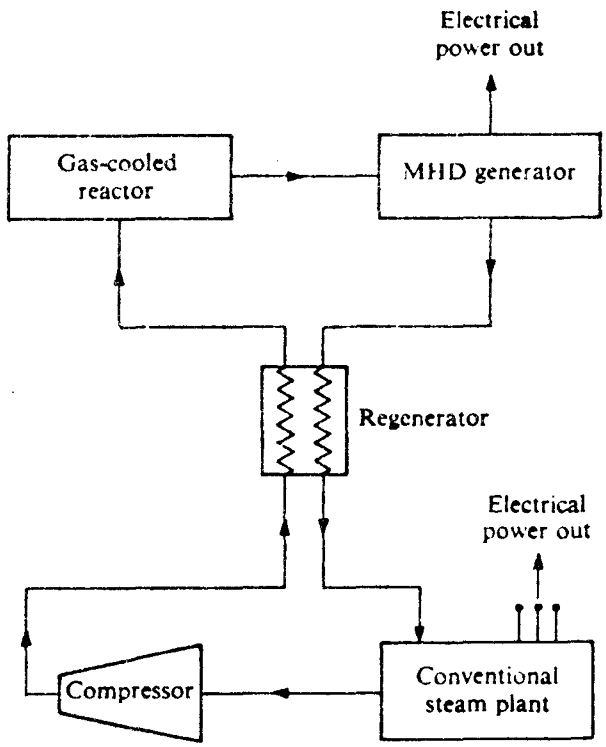


Figure 22

Closed-Cycle MHD

Nuclear powered MHD plants must, by necessity, be closed cycle. First, high temperature gas-cooled reactors, which are generally considered to be the most suitable type for MHD conversion, use helium as the coolant, which for economic reasons must be recycled. Second, non-equilibrium ionization, as described in Section (Technical Advantages and Disadvantages of MHD), must be used at the temperatures of typical reactor operation, and this phenomenon occurs only in monatomic gases such as helium, argon, or xenon. The basic components of the closed cycle system are similar to the open cycle. Both require seed recovery and steam generation units. The differences are in the substitution of a nuclear heat source for the combustor, and a regenerator in place of the air preheater.

A third type of MHD generator uses a liquid metal as the working fluid. While this fluid has relatively high electrical conductivity, the fluid velocities attainable in a practical device are low. Nonetheless, high power density generators are conceptually feasible and some tests have been run on small liquid metal generators, primarily with space applications in mind. For large-scale power generation, gaseous MHD plants have received primary emphasis.

Technical Advantages and Disadvantages of MHD: The major advantage of MHD systems lies in the high temperature at which the energy conversion process takes place. Thermodynamically, high temperature leads to high efficiency, and overall cycle efficiencies of 60-65% may be practically realizable with MHD generators. This would be advantageous from the standpoint of both fuel savings and reduced thermal pollution.

Simplicity of construction and the absence of moving parts are advantageous from the standpoint of reliability and maintainability. MHD systems may be started and put on line in minutes, making them potentially attractive for peaking. Because the power produced is proportional to the volume of the channel, units up to 1000 MWe (MHD power only) are considered feasible; this factor is of importance when considering nuclear heating, since reactor economics improves with size. MHD channels also exhibit an "efficiency of scale", i.e. larger units tend to be more efficient, again suggesting improved performance for large base-load plants.

MHD plants may have some advantages environmentally; it has been shown that SO_2 and oxides of nitrogen may be effectively removed in conjunction with seed removal, eliminating the need for additional scrubbing equipment [68].

While high temperature is the principal motivation for MHD, it also produces the most difficult problems. Development of suitable high temperature electrode and insulating materials currently represents one of the most challenging obstacles to successful MHD power generation. Not only are these materials subject to high temperature, but they must operate reliably in contact with extremely corrosive seed material.

The seed presents materials problems in the components for steam generation, air preheating, and regeneration as well. In addition, the seed recovery unit must be highly efficient; alkali metals are expensive and could be hazardous if allowed to enter stack gas scrubbers or if emitted from the stack.

Another problem with combustion-fired MHD generators is the sensitivity of the generating efficiency to the combustion conditions. A conventional generator is relatively insensitive to the specific composition of the fuel and the flame temperature. In an MHD generator, however, the electrical conductivity is closely related to these parameters, and hence they have a comparitively large influence on overall performance.

<u>Economics of MHD Power Generation</u>: As pointed out above, the principal advantage of MHD generation is the high efficiency possible in an MHD-steam combined cycle. The economics of such systems will thus be closely tied to fuel prices. Table XIV shows the results of a 1962 study by Lindley [69] which compared combustion and nuclear heated MHD topping plants with advanced conventional combined cycle plants. While the values of the capital and fuel costs are somewhat out-of-date, these figures are still useful for comparitive purposes. For both the fossil-fueled and nuclear plants, power costs for the MHD system are higher than the conventional system in spite of higher efficiency, due to the high capital cost of the magnet, inverter, and other auxiliaries required for MHD. This analysis did not include pollution abatement equipment such as stack gas scrubbers and cooling towers. A 1973 study [70] which included these components indicates that capital and generating costs for a 1000 MWe coal-fired MHD plant could be comparable to those of a conventional steam system. The latter study places specific plant costs at about $200 to $220/KW installed for both systems; with fuel estimated at 30¢/MBTU, generating cost ranged from 5.5 to 7.5 mills/KW-hr for MHD, compared with about 7.7 for conventional plants.

The major difference between the two studies is in the added cost of cooling towers. An increase of 15% in overall efficiency means a reduction of about 30% in heat rejection requirements, representing a significant reduction in capital investment.

Rosner and Dzung [71] made studies similar to those of Reference [69] and concluded that, at fuel costs of 30¢/MBTU, MHD generation is competitive with conventional light water reactors; at 20¢/MBTU, MHD is cheaper, with power costs estimated at 4 to 5 mills/Kwhr. Cooling

TABLE XIV

Comparison of MHD and Fossil Fuel Power Plant Costs
Source: Ref. 69

	Fossil fuel, open cycle steam	MHD-Steam
Thermal Efficiency (percent)	45	55
Capital Cost(dollars/KW installed)	97	140
Fuel Cost (cents/thermal KWh)	0.18	0.18
Cost of Power Delivered* (cents/KWh)	0.50	0.57

	Nuclear fuel, closed cycle steam	MHD-Steam
Thermal Efficiency (percent)	45	60
Capital Cost (dollars/KW installed)	182	224
Fuel Cost (cents/thermal KWh)	0.058	0.058
Cost of Power Delivered*(cents/KWh)	0.43	0.50

* Seventy-five percent load factor; capital and amortization charges, 12 percent.

tower costs were not included in this study, and the addition of cooling towers should again work in favor of MHD.

Research and Development Programs in MHD Generation: By far the most vigorous program of MHD research and development is that of the Soviet Union. The U.S.S.R. has vast reserves of natural gas, and MHD is viewed as a high-potential technology for efficient utilization of these reserves. In March of 1971 the High Temperature Institute in Moscow announced that an MHD plant, designated the U-25, was in operation on the Moscow power grid. This plant was designed to produce up to 25 MWe MHD power as a topping cycle to a 50 MWe steam plant. Original investment in the plant was about $200 million, and the plant is intended strictly as an experimental facility and not as a commercial demonstrator. Significant advances in air preheater design, MHD channel materials and construction, seed recovery, and boiler design have been made with this pilot plant. In the initial stage of experimentation the MHD channel was run at powers up to 4.5 MWe for continuous periods of about 3 hours. The second stage, which is now in progress, is aimed at 10 MWe operation for periods of up to 100 hours, and the third stage, which is scheduled for 1976, will attempt sustained operation at rated power (25 MWe) [72]. In addition to the U-25 project, several smaller scale experimental generators are in operation for specialized studies such as electrode materials and fluid dynamics. Design of a 1000 MWe demonstration plant is also underway, and construction of such a plant is scheduled to begin before 1980.

Laboratory scale efforts on open-cycle MHD are in progress in West Germany and Japan, with emphasis on basic research in high magnetic field performance and channel and preheater design. The Frascati laboratory in Italy is involved in small-scale research on closed cycle systems, with principal focus on physics of nonequilibrium plasmas. None of these programs envision commercial scale experiments in the near future [73].

Primary efforts on large-scale MHD generators in the United States have been centered at the Avco-Everett Research Laboratory. The laboratory has run a series of experimental generators since 1959. Tests have ranged from the 32 MWe Mark V, which ran at full power for about 1 minute at a time in a number of tests, to small scale generators running at several kilowatts for up to 200 hours. The largest current project is the Mark VI, a 250-300 KW generator designed primarily for aerodynamic and electrode testing. The Mark VI has run at power for over 100 hours in various experiments. A Mark VII generator of comparable size is under construction [74].

Other major efforts in open-cycle MHD are underway at Stanford University and the University of Tennessee, the latter aimed primarily at direct coal combustion and the former at basic generator channel design.

Closed cycle MHD research is being carried on at General Electric Company in Valley Forge, Pennsylvania. To date this work has focussed on characteristics of nonequilibrium plasmas, and has been performed in shock tube tests of very short duration [75].

The outlook for future funding of MHD development in the U.S. is not optomistic. The Electric Research Council has recommended total research expenditures to the year 2000 of $238 million for open-cycle,

$115 million for closed cycle, and $33 million for liquid metal MHD, and has assigned low priority to these projects [76]. The federal government also views MHD as a low priority in overall energy development, with a total of less than $10 million recommended for the 1975-1980 period [41].

Outlook for Commercial Application of MHD: Magnetohydrodynamic generators, while offering the promise of high thermal efficiency, appear to be of questionable economic merit for large scale power generation because of the high capital costs associated with the magnets, preheaters, and seed recovery units required for such systems. With fuel costs highly uncertain, but obviously rising, open-cycle MHD presently faces a questionable future, and progress in closed-cycle systems is still in its infancy.

With these facts in ahnd, and given the dismal outlook for future research funding in the field, MHD must be considered a "back-burner" technology, with commercial systems in the U.S. unlikely in this century.

B. Transmission Technologies

1. High Voltage AC

a. Overhead

Electrical energy consumption is expected to grow at a faster rate than total energy consumption because of an increasing reliance on central power plants as the most readily available and economical devices for the utilization of the nations energy resources, namely coal and nuclear fuels. In the period of study, between the present and the year 2000, it is estimated that it will be necessary to deliver approximately seven times as much energy to load centers as is currently delivered, without proportionately expanding the number of transmission lines on the acreage for rights-of-wary and substation sites.

The greatest factors affecting energy transport system facilities in the future will be those stemming from environmental considerations. Since the major share of land use projected for the energy system is for transmission rights-of-way, this and the visual impact associated with it, will be the primary environmental concern. Current means of solving this problem by placing transmission lines underground, are expensive--in many cases prohibitively so since the cost ratio of underground to overhead bulk power transmission lines ranges from 10:1 to 40:1 for equal capacity. Many factors influence this cost differential, but, since as much as 50 to 60 percent of the underground transmission cost can be attributed to installation labor, the prospect for major reductions in the ratios is not encouraging. It appears that overhead transmission will continue to dominate and underground transmission will only be used where laws and economic factors leave no other choice.

With the huge blocks of power that must be transferred and the distances involved it becomes apparent that the major share of this burden will fall on overhead lines. Since electrical energy can be more efficiently transferred at higher voltages and existing right-of-ways can be more efficiently used the general trend is to increase voltage levels. The predictions for future voltage levels are 1100 KV by 1980, 1300 KV by 1985, and 1500 KV by the year 2000. The most severe limiting factor in the extension of transmission line voltages is the electrostatic field between the conductors and the ground; while it is evident at the 765 KV level, it is a major difficulty above the 1000 KV level. In addition to noticeable discomfort of people and animals, induced currents can reach levels above let-go currents (i.e., the amount of current below which voluntary disconnection is possible) when persons make contact with metal structures or vehicles. Corona, radio and television interference and audible noise are also more of a problem at high voltages.

A study has been done on American Electric Power's 765 KV transmission lines to determine the impact of some of the problem areas. Currently AEP has 1050 circuit miles of transmission through the states of Indiana, Ohio, Pennsylvania, and West Virginia on which the operating voltage is 765 KV. The basic results of this study are that radio and television interference are not a problem during fair weather but during foul weather they are noticeable near the transmission lines. Audible noise at the edge of the ROW is not a problem except during early morning fog when ambient noise is lowest and the fog causes increased audible noise to be generated. Electrostatic induction is not to the level where it would be dangerous; being noticeable beneath the lines, at the threshold of perceptibility at the edge of the ROW but imperciptible 100 feet from the ROW. Similar results have been obtained in test of Hydro Quebec's 735 KV lines of 236 miles in length.

This study of AEP's 765 KV lines provides some data for evaluating the fundamental problems of higher voltages on transmission lines. The electric field problem can be controlled by providing adequate vertical clearance to ground and if necessary by adding electrostatic shielding in critical areas; there is room for more development in this area. The acoustic noise problem is controlled by the electrical gradients around the conductors, consequently it is influenced by conductor size, bundling configuration, phase spacing, height above ground, and possible materials technology. It can be expected that current developments at ultrahigh voltages (voltage exceeding 1000 KV) will be applicable to these EHV transmission problems and that the current concerns over 765 KV transmission lines will be eliminated.

Current research in EHV and UHV transmission is being carried out in the U.S. by Bonneville Power Administration, who has two one-mile test lines of 1100 KV, and Electric Power Research Institute who has a 3-phase 1500 KV test line. The U.S.S.R. has a design for a 1200 KV transmission line for Western Siberia and ENEL, the Italian State Utility, has a test line of 1000 KV. In addition to the study and analysis of overhead electrical power transmission phenomena, developmental work is required for major components such as transformers, circuit breakers, lightning arresters, structures, insulators, conductors and associated hardware. It is generally felt that current research will make 1500 KV transmission lines available by the year 2000.

The major transmission voltage currently used in Texas is 345 KV, with some 500 KV transmission. The next step up the voltage scale for bulk transmission would be to 765 KV which is the current voltage level of AEP in northeast central U.S. The basic reasons for increasing voltage levels are more efficient land utilization and smaller transmission losses. The Bonneville Power Administration is currently studying the feasibility of building a 1100 KV double circuit transmission line stretching 175 miles over the Cascade Mountains. They estimate that this one line could transfer 8000 MWs of energy with a 250 MW smaller loss than the existing trans-Canadian 500 KV lines. This would cut BPA transmission losses by 1/3 and could save an estimated 1.75 million barrels of oil per year. Table XII gives projected EHV transmission line additions for the time period 1972 to 2000. This is in our opinion an (optimistic) estimate presented to the Federal Power Commission by Frank A. Denbrock, Group Vice President of Commonwealth Associates, Inc. [64].

Higher transmission voltages are advantageous from economic and certain environmental standpoints due to better land utilization. To deliver the same amount of energy as a single 765 KV circuit would take 5.5 circuits of 345 KV transmission lines, or equivalently, when the 765 KV line would require 16 acres/mile the 345 KV lines would require 35 acres/mile. Tables XIII through XV give comparisons of different voltage levels, they are from "The Changing Energy Business and Its Effect on Energy Transport Systems." This improved land utilization is offset by the fact that a large tower, 120' by 110' for 765 KV, as opposed to 84' by 60' for 345 KV, is sitting on the land which has a large visual impact. This problem of esthetics may be rather significant especially at even higher voltages where even bigger towers are required; some designs for 1100 KV towers use heights of 150' and at 1500 KV some are

180' tall. A string of these towers across the land would be very noticable even though twenty 345 KV towers would be replaced with a single 1500 KV tower.

Another consideration in going to higher voltages is the amount of power to be transferred. For reliability purposes at least a double circuit transmission line is needed. This means that there must be a need to transfer at least 4000 MW of power before going to 765 KV whereas for 345 KV there is only the need for the transfer of 800 MW of power; however by the year 2000 demand will have increased five to eight times the current level and such a 765 KV or even higher transmission system could be efficiently utilized. This would be especially true if large power plants were built, greater than 4000 MW, which appears feasible.

Major research will continue in the area of AC overhead transmission since this will be the major method for bulk energy transfer. Alternate systems such as DC will be used only for long distances or for difficult control problems and underground will only be used in urban and suburban systems where environmental demands are great enough to override economic considerations.

Microwave and Charged Particle: Both microwave and charged particle transmission involves much speculation. They are intellecutally attractive but basic problems such as output power reconversion require inventive developments of a most fundamental nature. Given time and effort both would be achieved but not, in our estimation, before the year 2000. In addition, the economic attractiveness of this kind of system relative to other transmission alternatives is open to serious question.

Two approaches have been suggested for the transmission of microwave radiation. In the first system the output of the generator is converted to microwave energy, conducted through a transmission line consisting of a closed waveguide, and then reconverted and processed in a form suitable for distribution. In the second system the energy is not carried by a waveguide but is radiated by an antenna, bounced off orbiting reflectors and received by another antenna.

In a charged particle beam system, the generator output is converted to kinetic energy via the acceleration of charged particles. The transmission line is now an evacuated conduit for the beam, and the electrical power is recovered by suitable retardation of the charged particles at the output end. Charged particle transmission has low losses but presently there is no known means for reconverting the kinetic energy of the particle beam into electrical power with anything close to the efficiency required for a practical system.

According to FCST Energy R & D Goals Study, the present status of microwave transmission via closed waveguide is [65]:

(1) At present, adequate engineering knowledge exists only for construction of waveguide power systems at relatively low frequencies.

(2) The low frequency systems possess the advantage of using dominate mode transmission, but the waveguides must have a large cross sectional area to keep losses sufficiently low; such as 116 by 58 feet.

(3) Microwave power transmission in multimode circular waveguides is attractive because of the high power capacity and low loss possible in waveguides of modest size such as 6 to 10 feet in diameter.

(4) More research is needed in techniques for construction of a waveguide, such as laying a 10 foot diameter tube in a straight line with very small tolerances, in microwave generators and couplers, and basic research is needed in reconversion.

There are no estimates of the time required or the expense involved for developing microwave transmission up to a commercial process. Because of the current state of development and the magnitude of the work to be done, it is the opinion of this research group that microwave transmission will not be a viable commercial means of transmitting electric power by the year 2000.

The present state of charged particle technology is:

(1) Present technology provides means to transfer energy to charge particles via linear accelerators.

(2) The transmission of charged particles over long distances can be achieved at low energy loss.

(3) There is no means for reconversion of the beam back to electrical energy efficiently.

(4) The scheme has many attractive properties from a conceptual standpoint, but this concept has received very little attention in terms of research effort and financial support.

In summary, microwave and charged particle transmission can best characterized as being in an early conceptual stage. No basic apparatus has been constructed for transmitting electric energy by these means except on a laboratory scale.

TABLE XV

PROJECTED EHV TRANSMISSION LINE ADDITIONS IN MILES (U.S.A. ONLY)

PERIOD	345 Kv	500 Kv	765 Kv	1100-1300 Kv	1500 Kv
1972	3,341	1,662	130	—	—
1973	2,640	772	134	—	—
1974	2,584	1,516	256	—	—
1975	2,701	623	250	—	—
1976	1,740	599	400	200	—
1977-80	6,000	3,000	1,000	400	—
1980-90	15,000	9,000	8,000	1,000	1,000
1990-2000	18,000	10,000	9,000	2,000	1,500

TABLE XVI

IMPROVED LAND UTILIZATION WITH INCREASING VOLTAGES

Kv	MIN. R.O.W.	ACRES/MILES	SIL Mw	Mw PER ACRE*
345	80	9.7	400	42
500	100	12.1	900	74
765	135	16.4	2200	134
1100	160	19.4	4500	221
1300	180	21.8	6200	284
1500	205	24.9	8000	325

* V-STRING CONFIGURATION

TABLE XVII

EQUIVALENT NUMBER OF 345 Kv CIRCUITS TO DELIVER ENERGY AT DIFFERENT VOLTAGES

Kv	SIL Mw	NO. 345 CIRC.*
500	900	2.25
765	2200	5.5
1100	4500	11.25
1300	6200	15.5
1500	8000	20.0

* V-STRING CONFIGURATION

TABLE XVIII

LAND REQUIREMENTS - ACRES PER MILE

Kv	SIL Mw	ACRES/MILE	345 Kv ACRES/MILE*
500	900	12	24
765	2200	16	35
1100	4500	19	70
1300	6200	22	93
1500	8000	25	116

* V-STRING CONFIGURATION

b. Underground AC Transmission System

Underground systems have played only a limited part in the transmission of electrical energy in the United States. Less than 2000 circuit miles had been installed underground by the end of 1972 compared with almost 167,000 circuit miles of overhead transmission. Two principal reasons are (1) as transmission voltages have risen over the years, the technology for overhead lines has been available while the technology for underground cables of equivalent capability has generally lagged and (b) the cost of underground transmission has been much higher than for equivalent aerial circuits. However, their role has been increasing in importance since underground systems have made possible delivery and distribution of electrical energy into and within densely populated urban areas, where their relatively high cost of land use and right-of-way can be fairly well justified.

In the United States, the cost ratio of underground to overhead bulk power transmission lines can range from 10 : 1 to 40 : 1 for equal capacity. Many factors influence this cost differential. Therefore, it appears that overhead transmission will continue to be dominant, with underground systems being used in those cases where technological and social conditions leave no alternative.

Underground transmission cables are currently commercially available. There are basically two major types of high voltage underground power transmission calbes in use at the present time - the self-contained and the pipe type cables. For the self-contained cable, each phase consists of a conductor formed over a hollow core insulated by oil impregnated paper and protected by a lead or aluminum sheath. To prevent voids from forming the cable insulation is kept under 1 atmospheric pressure at all times. In the case of pipe-type cable, the three phase conductors are retained within a steel pipe and the pressure is applied by filling with oil or gas under a relatively high pressure of 13 to 15 atmospheres. High pressure oil filled (HPOF) pipe type cables are in commercial service at voltages up to 345 KV with a maximum capacity of approximately 450 MW (naturally cooled). Systems up to 500 KV are now being tested. The pipe-type cables are the most common type in use in the United States. The reasons for this are as follows: (1) the steel pipe provides physical protection to the cable and (2) this design provides a means of overcoming the frequent legal limitations on the length of trench that can remain open at any one time in urban areas.

The technological and economic problems associated with the use of HV pipe-type cable may be summarized as insulation and capacity problems. With currently available insulation systems, the dielectric losses increase rapidly with increases in voltage levels. For a 345 KV cable on a typical duty cycle, dielectric loss can run as high as 26 watts per circuit meter. Because the total permissible loss on such a line is about 72 watts per meter, not much room is left (46 w/m) for I^2R losses in the conductor. The result is that the power-transmission capability of the 345 KV system is only 4.2 times that of the 69 KV system.

At 345 KV, the average line cost in 1970 dollars for a 48 KM underground circuit in a suburban area would be around $430,000/Km as against $74,000/Km for an overhead circuit, but the overhead line would have a capability of more than twice that of the underground line (1050 MW vs. 484 MW). In addition to the line cost, the underground circuit would require $3,760,000 for compensation and terminal facilities not needed for overhead, so that the cost per megawatt-kilometer would be $1,050 for underground against $70 for overhead.

A third type of cable, now entering the high voltage field is extruded synthetic insulated cable or solid dielectric cables. Materials such as polyethylene, cross-linked polyethylene, ethylene-propylene rubber are now being used in up to 138 KV systems and are being tried experimentally at 230 KV. So far, solid dielectric cables have received relatively little application in the United States for two reasons.

(1) The emphasis on urban installations, satisfied by pipe type cables has left little demand for directly buried systems and

(2) The reliability record of installed systems has been poor because of unpredictable breakdowns in the dielectric.

Since 1968 fewer than 10 circuit miles of extruded dielectric cables operating at 138 KV and with a capacity of 200 MW have been installed in the United States. All of the installations have suffered dielectric breakdowns.

Research and Development: Six 138 KV cables have been tested at Waltz Mill Pennsylvania. In France a 225 KV (1600 kcmil copper conductor) 350 foot link (300 MW) has been in service for 2 years. From current investigations of the mechanism and causes of insulation breakdown, it is apparent that research both at the basic and the manufacturing level is required. At the same time it is desirable that both the voltage and the capacity ratings should be increased to 345 KV and 500 MW respectively. This should be technologically fully developed by the late 1970's.

Compressed Gas Insulated Cable (CGI): The isolated-phase compressed gas cable is a rigid system in which each single phase conductor consists of a copper or aluminum tube supported by spacers within an outer sheath of extruded aluminum pipe. The space between the conductor and sheath is filled with a pressurized insulating gas such as sulfur-hexafluoride (SF_6).

The first installation of CGI cable was completed in 1970 on the system of Consolidated Edison Company of New York. This system is 600 feet long and will carry up to 3,350 amperes at 345 KV of power capacity up to 2000 MVA. Another isolated phase system 800 feet long at 500 KV is now on order. These trial installations will produce useful data to further the development of this type of cable. The Electric Power Research Institute is sponsoring a research project at MIT to determine the feasibility of using CGI cable at voltage levels in excess of 500 KV. EPRI is also sponsoring the development of installing 3 phases in one pipe in order to produce a more economical design.

Advantages of CGI Cables: For high voltages, high power underground transmission, compressed gas insulated cables have the following principal advantages:

(1) The charging current is greatly reduced because of the unity dielectric constant of the insulating gas SF_6 and the favorable electrode geometry.

(2) Negligible dielectric losses

(3) Good heat transfer characteristic of SF_6

(4) High thermal stability

(5) The lower charging current, low dielectric losses and the high

current carrying capacity, give a considerable increase in the critical length possible for the underground lines.

Research and Development: There are a number of inter-related technical and economic problems that must be evaluated in the design of a CGI cable systems, such as the lighting and switching surge performance of such systems particularly when used in conjunction with overhead systems. However, there are enough attractive features to justify the present trial installations and continuing studies to further develop and optimize such a system. They should be expected to be commercially available within 8 to 10 years.

Cryogenic Systems: Cryogenic systems operate at temperatures much below ambient temperatures in order to take advantage of the fact that the electrical resistance of a metal diminishes as its temperature is lowered. Although the ohmic losses in the conductor are reduced this benefit is partially offset by the refrigeration that is required to remove the heat leaking in from the outside and the residual losses which appear as heat dissipated at the low temperature.

Generally there are two types of cryogenic systems: Resistive Cryogenic Cable (Cryoresistive). In theory, the advantage of cryoresistive cables is the large reduction in the resistance of the conductor and the increase in line rating that is possible while avoiding the high capital cost required for superconductivity. The system operates at about 80°K and is cooled by liquid nitrogen or hydrogen. In one design, the stranded flexible aluminum conductors are insulated with synthetic tapes or paper in a manner similar to a conventional oil-paper cable. The three phases are contained within a cryogenic enclosure through which liquid nitorgen flows as a coolant. This system is proposed for high power operation at approximately 3500 MW. The other cryoresistive system consists of three hollow rigid phase conductors mounted within a single vacuum envelope. The vacuum provides both thermal and electrical insulation between phase conductors and the envelope. The coolant, liquid nitrogen, flows inside the conductors. It is designed for a capacity of 1000 MW at 230 KV. Both types of cryoresistive systems have gone through experimental stages at the Watz Mill test center and are approaching demonstration project status. The project is sponsored by EPRI. These are expected to be technologically available by the early 1980's but will not in our view be economically competitive until a much later date.

Superconducting Cables: The DC resistance of the superconducting material becomes identically zero although certain hysteretic losses remain when the metal is exposed to AC electromagnetic fields. In one design, three coaxial phase systems in which the niobium superconductor is plated upon copper tubes, are arranged in trefoil. The liquid helium acting as coolant and dielectric, flows between each phase conductor and the shield. The whole conductor is contained within the double walled vacuum cryogenic enclosure. The second superconducting system resembles a cryogenic version of the conventional pipe-type cable. These systems can operate at unusually high current densities and consequently have very large power capacity of up to 10,000 MVA at 345 KV. Both systems operate at approximately 5°K. At this temperature, the power requirements and the capital costs of the refrigeration system are very high.

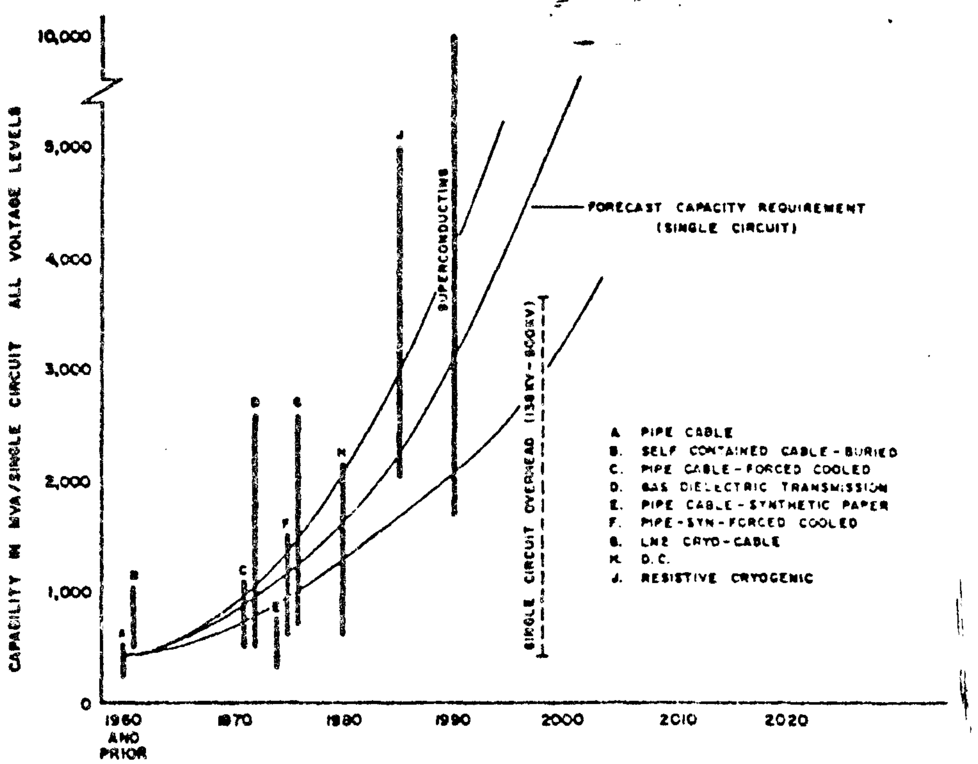
Research and Development: Superconducting cable research to date indicates that a continued research and development program is warranted. Such a program is estimated to cost about $8 million, exclusive of test facilities and would be extended over a period of at least 10 to 15 years. Therefore, it is not expected that the technological developments will be completed before the early 1990's and even then the economic competitiveness of this alternative is far from certain. Research is being carried out under the sponsorship of EPRI.

The capabilities of underground transmission lines must increase in the future to meet the needs of power systems which have been doubling in size every ten years. Graph 1 shows the range of circuit capabilities in MVA for various actual and proposed systems plotted against estimated date of commercial availability. This plot shows that systems now contemplated should meet industry requirements up to the year 2000.

Graph 2 shows the same underground systems with estimated unit costs in dollars per mile per MVA transmitted against date of commercial availability. This shows that costs are expected to come down as new systems become available, and the future underground transmission unit costs may be one half or even one-third of present day values.

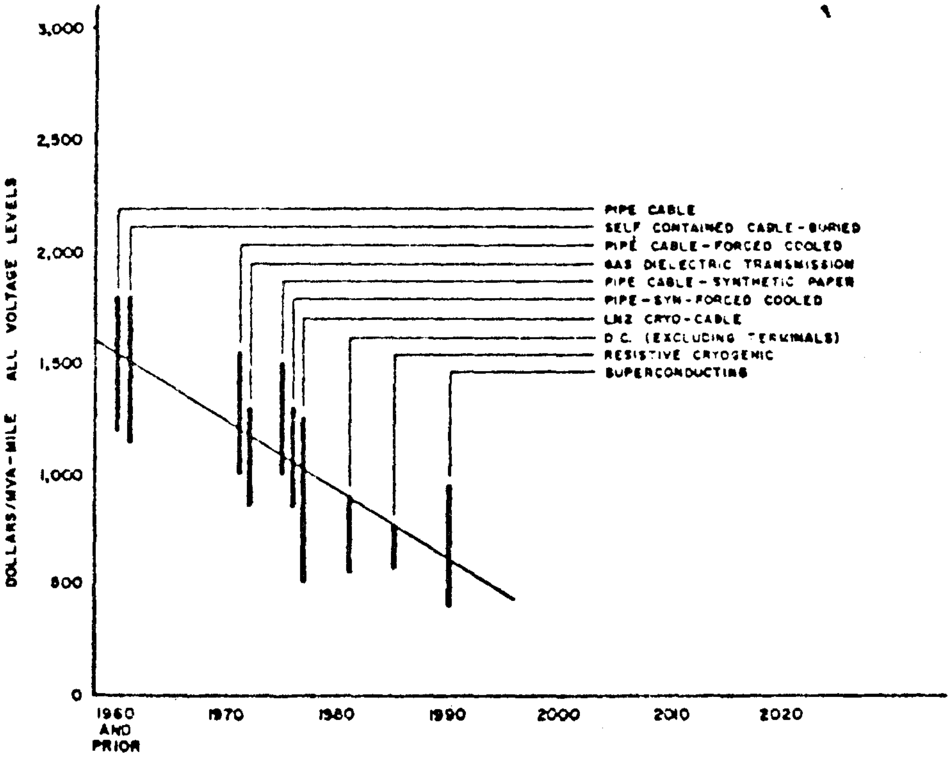
Economic Comparison of Underground Transmission Costs: A fairly detailed underground transmission cost for different cable types at different voltage levels is shown in Table XVI. The estimated costs are given in $/MVA mile. Table XVII gives a general picture of the estimated total capital cost of several selected underground transmission systems. The estimated total capital costs is given in $/mi with corresponding voltage level and power capacity. In our estimation the data presented in Tables XIX and XX is extremely optimistic and should not be depended upon without further investigation.

1146 *Volume 35—Proceedings of the American Power Conference, 1973*



—Existing and proposed cable systems—date of availability versus load capability.

Graph 1



—Existing and proposed cable systems—estimated unit investment costs.

Graph 2

TABLE XIX

Underground Transmission Costs

Type of cable	Voltage KV	Power MVA	Estimated Costs $/MVA mile	Estimated by
Paper-oil pipe type	138	200	2,640	actual
	230	400	1,580	actual
	345	650	1,220	actual
	500	725	1,300	--
Paper-oil pipe type forced cooled*	500	2,200	470	--
	750	2,300	480	--
Extruded type cables	138	300	1,500	actual
	230	500	1,100	--
	345	740	910	--
Synthetic paper pipe type*	500	1,000	1,050	Phelps Dodge
	750	1,500	750	
Synthetic paper forced cooled	500	2,800	410	Phelps Dodge
	750	3,500	344	
	1,000	3,800	304	
SF_6 insulated	345	4,000	500	ITE
	750	10,000	380	
SF_6 insulated	230	600	1,600	H.V. Power Corporation
	345	1,200	1,100	
	500	2,200	700	
	750	4,000	530	
	1,000	7,500	320	
SF_6 insulated forced cooled	345	4,000	350	H.V. Power Corporation
	500	6,000	300	
	750	10,000	230	
	1,000	15,000	200	
Cryogenic	500	3,500	700	General Elec.
Super conducting	69	423	1,720	Union Carbide
	138	1,690	601	
	230	4,710	307	
	345	10,590	201	
Super conducting	230	2,500	520	Brookhaven Nat'l Labs
	345	5,500	300	
DC**	±400	1,120	513	Phelps Dodge
	±600	1,820	392	

*$1,200 to $2,000 per MVA fro transformation on both ends, if necessary
**$50,000 per MVA for rectification on both ends.

TABLE XX

Capital Costs of Selected
Underground Transmission Systems*

Type of Transmission System	Maximum Constant Rated Capacity (MS)	Estimated Total Capital Costs ($/mi)
HPOF (Naturally cooled, 345 KV)	450	747,770
HOPF-PPC (Forced cooled, 500 KV)	1900	1,542,600
Compressed Gas Insulated (Naturally cooled, 500 KV)	2200	2,944,400
Rigid Superconducting (138 KV)	3390	2,190,000
Cryoresistive (Tape insulated, 500 KV)	3500	2,327,000
Superconducting AC Cable (138 KV)	3400	2,190,000

* These estimated capital costs from the basis of the transmission costs in 1971.

2. High-Voltage DC

a. Overhead

The purpose of this section is to evaluate the salient features of high-voltage DC transmission system, reviewing the current stage of development, commercial application and possible future trends in its technology. Brief comment on the research and development, comparison between points of advantages and disadvantages are also included in these studies.

Modern high voltage DC transmission system development is still considered to be in a early stage. As a means for energy transportation, DC transmission has several inherent features which make it particularly adaptable to certain applications. However, it is not a total substitute technology for AC transmission. Instead, DC should be investigated in those special instances where, on both a technical and economic basis, it may properly supplement other forms of energy transportation. Several factors are important for the use of a DC system: (1) to transmit bulk power over a long distance, (2) to transmit power for considerable distances underground, for example, into the center of and within a heavily congested urban area, (3) provide an asynchronous tie between two independent AC systems, example, asynchronous tie between Hydro Quebec in New Brunswick at Eel River, and (4) a DC link inserted into an otherwise all AC network, may provide a means for control of power flow and for damping AC system disturbances.

<u>DC Transmission System</u>: The present status of DC technology restricts its use mainly to point-to-point transmission with very limited feasibility

for providing intermediate tapping. The ability to control magnitude and direction of power flow in two-terminal transmission, and the absence of inductive and capacitive reactance effects are its major advantages. DC lines, excluding the converters do not require reactive power, hence, the line losses associated with reactive power flow are eliminated. The absence of skin effects on the conductors reduces resistance and losses. More important, steady voltage in the cable makes for reduced demand on the dielectric strength of the insulation and eliminates polarization losses and the continuous flow of charging current. Because of the absence of reactive currents and the skin effect losses, the useful DC current can be greater than the AC current for the same total power loss.

DC power transmission may be continued at reduced voltage, if the pole to ground insulation is reduced as when the insulators are heavily contaminated. To minimize the flow of DC current through the earth and possible corrosion problems in undergroung metallic structures such as pipe lines, careful attention must be given to the location and design of the DC ground electrodes and to the design and operation of pipe line protection systems. Because of the problems associated with interference with other systems such as pipe lines, it is not likely that ground return DC system will be used.

<u>High Voltage DC Transmission System in Existence and Planned</u>: In the United States there has been relatively little experience in the construction of overhead DC transmission systems. However, a long overhead DC line (Celilo-Sylmar) for the Pacific Intertie has been constructed in the United States. This line is nominally ± 400 KV and is 846 miles long. It is the longest DC circuit now in existence. Much of the design

criteria and test information was collected at the Bonneville Power Administration dc test center. Table XVIII shows the HVDC power transmission projects in commission and planned all over the world.

Technical Evaluation: Present State and Future Trends of HVDC Technology

Power Reversal

The DC current flow is always in the same direction through both the transmission line and the conversion equipment. Power reversal is accomplished by reversing the polarity of the terminal voltages. In a DC system, power flow is achieved by maintaining a higher voltage at the input rectifier than at the output inverter. Since mercury arc converters and solid thyristers conduct current in one direction only, reversal of the power flow must be accomplished by reversing the voltage polarity at the converter terminals and an adjustment of the voltage difference between them. The procedures may be summarized as follows:

(1) The converter firing times may be adjusted either manually or automatically, which simply reverses the DC polarity of the converters and line conductors. Switching of line or converter terminals is not necessary.

(2) In the multi-terminal case, the power flow is brought to zero by adjustments of converter firing time; the connections between some, but not all, converters and the DC line are then transposed by switching; and the power is resumed. This procedure maintains the original polarity on the line conductors but reverses direction of current flow in certain line sections.

Switching

There is at present no DC circuit breaker available for high voltage operation. However, some study and preliminary development in this area is reported underway. Based upon normal developmental times for equipment, it will require approximately 10 years before a reliable DC breaker can become commercially available. To date, the most promising approach to DC current interruption appears to be the insertion of a high frequency current through the DC breaker contacts at a critically determined time during contact separation so as to create an artifical current zero and permit interruption. However in a point-to-point DC system the valves or thyristers themselves function as circuit breakers. During a fault on the line, the controls automatically adjust to clear the fault and restore service.

Insulation

Overhead line insulation on a DC system is determined basically by the length of the insulator leakage path. A DC line, in contrast to an AC line, operates at a constant voltage, the distribution of voltage stress across an insulator string is determined essentially by its surface resistance. This surface resistance is altered by contamination which in DC systems tends to concentrate the voltage stress across the uncontaminated portion of the insulator string. For this reason fog-type insulator units are recommended for DC use. Switching surges in DC operation are expected to be less than for AC, being on the order of 1.6 to 1.7 times line-to-ground voltage as compared to 2 to 3 times maximum crest line-to-ground voltages for AC. The voltage gradient across the insulation of DC cable is determined by the resistance distribution across the insulation and there is no dielectric heating of insulation in a DC system.

Corona and Radio Interference

Experiments carried out over many years in Sweden, Canada and Russia have proved that DC has considerably more faborable RI and corona-loss characteristics than AC. Tests have shown that there is practically no RI caused by corona on a negative conductor, but that there is RI produced from a positive conductor. Corona is the object of continuing investigation, but additional theoretical and experimental research is required for better technology. According to present knowledge:

(1) RI from DC lines decreases during inclement weather - the opposite of the effect for AC lines

(2) Most of the RI originates at the positive conductor of DC lines

(3) RI appears to be considerably less in calm weather than in high winds. Line configuration appears to affect corona losses on DC lines more than on AC lines

(4) At 500 KV, DC the corona loss in fair weather, from a bipolar dc line is approximately the same as or slightly less than that from a three phase 500 KV AC line.

Reliability

(1) Component Reliability

(i) A single DC line and an AC line are almost equally exposed to man-made accidents and to natural hazards. A two conductor DC line with ground return is substantially equivalent in reliability to a double-circuit (6-conductor) AC line

(ii) Both AC and DC systems must rely on good communications between line terminals

(iii) DC converter stations may have more elaborate control requirements than AC line terminals, due to the auxillary equipment.

(2) Operating Reliability

Operating experience to date has shown that modern converter equipment can be built to give very reliable service.

The electrotechnical director of the Swedish State Power Board has stated that "From the very beginning, the system has proved its applicability for practical service. The link has worked satisfactorily. Operational records verify a high degree of reliability in operation which is comparable to that of an AC transmission system."

Economic Evaluation

The combination of the lower cost transmission line and the relatively high cost of a DC terminal equipment makes DC economically comparable with AC for overhead transmission distances of approximately 400 miles or longer in length and for underground distances of approximately 30 miles or more. Obviously if the systems compared are dissimilar in other important respects, the choice of plan may not be based on break-even considerations alone. A comparison of AC and DC transmission cost and break - even points for different voltage levels is shown in Figures 16, 17 and 18 (FPC, 1964) as of the 1970 FPC report. The break-even distance of AC and DC overhead line facilities in point-to-point applications ranges from 450 to 900 miles. Factors that are likely to affect the economic attractiveness of DC in different situations include the following factors:

Transmission distance

Power Levels - initial and final design levels

The need to serve intermediate loads

The cost of power losses

Uncertainty in DC terminal equipment cost

Reliability considerations

The need for power reversibility capability in the DC converters

The cost of land uses for the terminal equipment use and for the right-of-way (Generally DC ROW requires less land use than AC) of the same power transmission capability

Environmental impacts etc.

The following specific values are considered to be closely representative of those to be expected in practical situations.

DC Overhead Transmission Line Costs:

KV	Structure	#Circuit Bipolar	Capacity MW	Conductors MCM-ACSR	ROW (ft)	Labor & Material Cost $/mi	R/W & Clearing Cost $/mi	Total Cost $/mi
±250	Steel	1	600	1-3000	125	$10,000	$56,000	$66,000
±375	Steel	1	900	1-4000	150	12,000	68,000	80,000
±500	Steel	1	1200	1-4000	175	14,000	78,000	92,000

DC Underground Transmission Line Cost

KV	Type of Construction (bipolar)	Conductor Size (MCM)	Type of Cable	Thermal Capability (MW)	Materials Labor Cost per mile	Fixed Cost of Acessories per Circuit
±250	Single Circuit	1500	copper-pipe type (HPO)	540	$264,000	$ 80,000
±375	Single Circuit	2000	copper-pipe type (HPO)	760	634,000	100,000

Notes: (i) Fixed cost includes two cable terminations per circuit and one pressuring plant with accessories

(ii) MW capability based on 75% daily load factor

DC Converter Stations with Reactive Cost Included:

± 250 KV	1000 amp	500 MW	$31.00/KW
± 375 KV	1330 amp	1000 MW	28.50/KW
± 500 KV	2000 amp	2000 MW	26.00/KW

Notes: The cost may be reduced by $3.00/KW if reactance at sending terminal is not required

Operating and Maintenance Annual Cost Ratio 1/2 percent of Investment

Converter Station Losses 1 percent Converter Station Rating

Figure 23

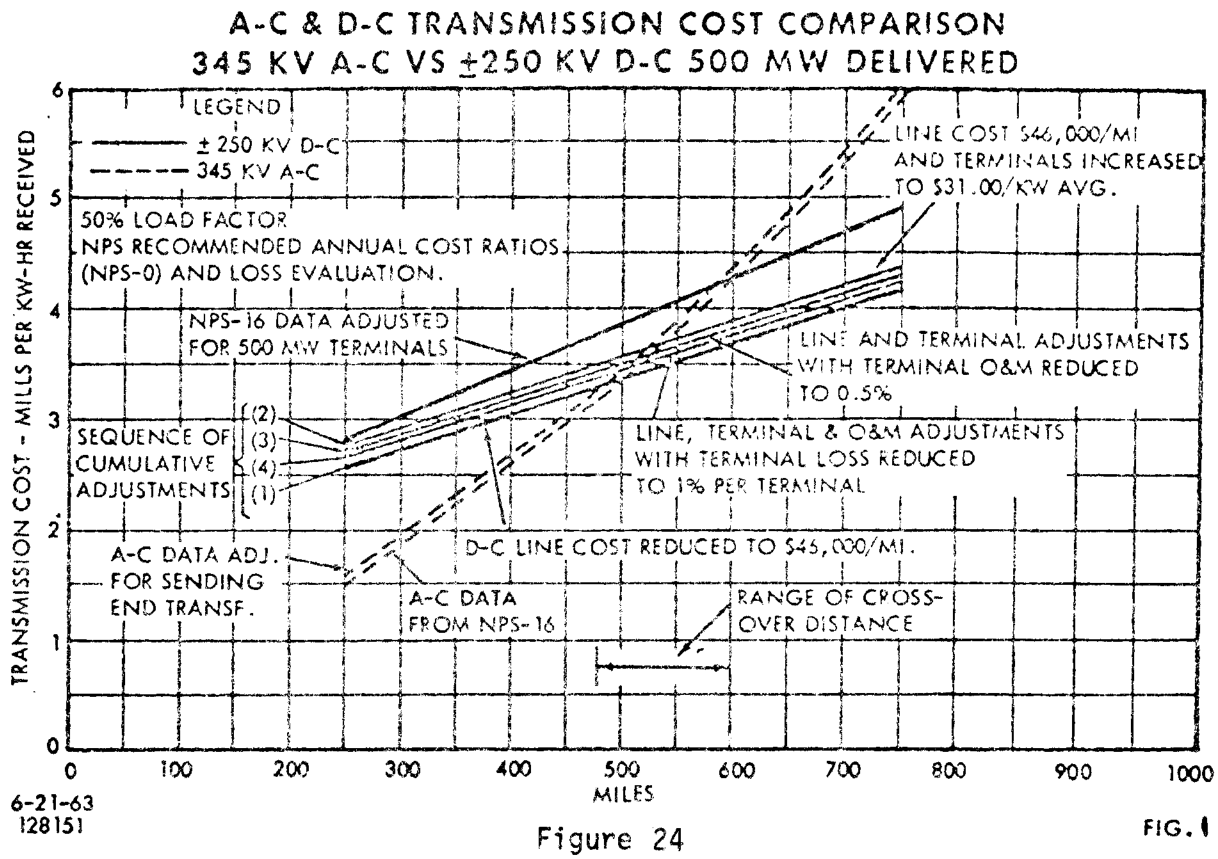


Figure 24

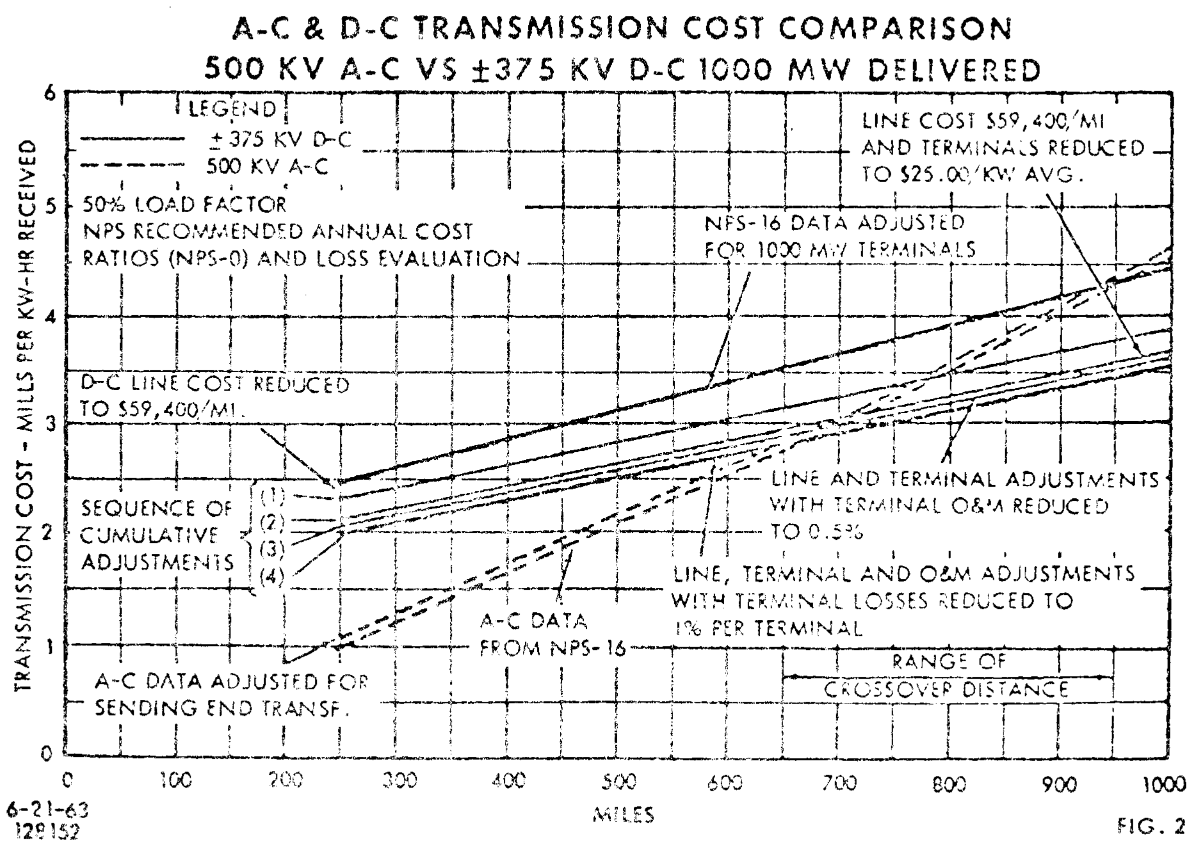
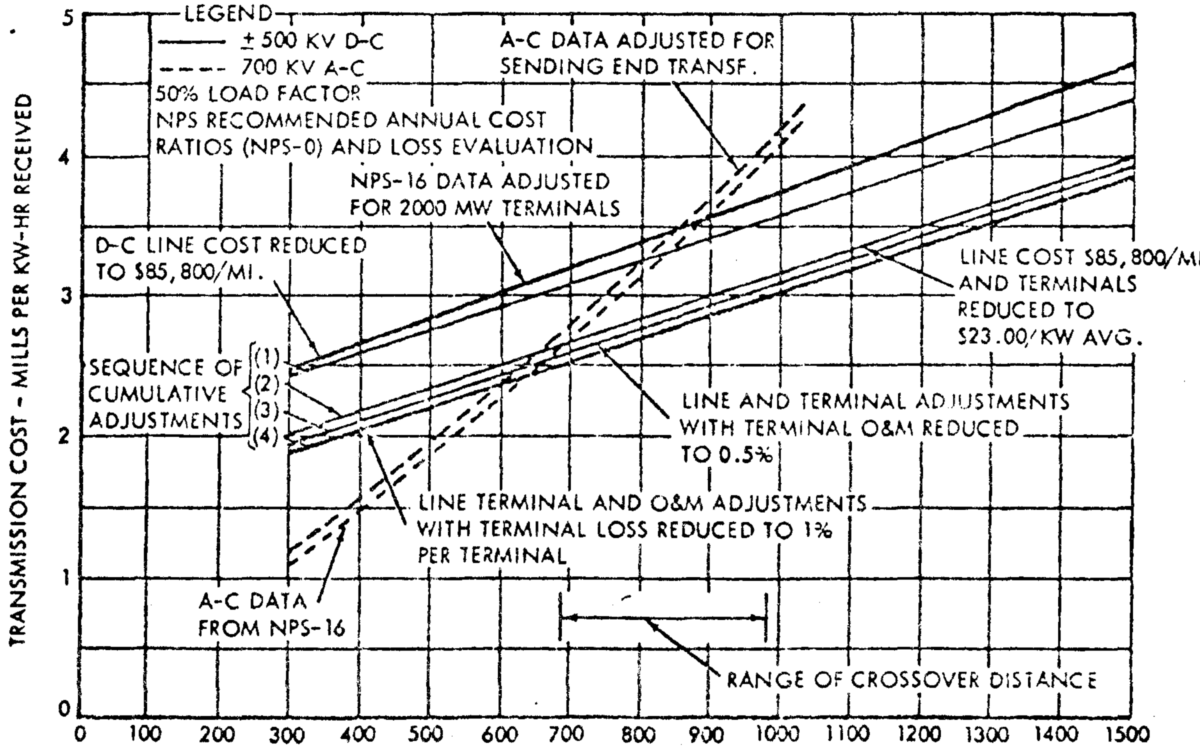


Figure 25

A-C & D-C TRANSMISSION COST COMPARISON
700 KV A-C VS ±500 KV D-C 2000 MW DELIVERED



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Comparisons Between Advantages and Disadvantages of DC Systems

Advantages

Lower power losses for a given line resistance, (DC voltages eliminate the continuous flow of charging current in the cable, thus removing I^2R losses due to these currents).

D-C lines operate without voltage drops due to series inductance and electro-magnetic induction between lines.

No dielectric losses and induced losses in the surrounding structures.

No effects of reactive impedance in the lines.

Total power capacity of DC system is approximately 1.5 to 2 times that of the A-C in the overhead case.

Corona, radio-interference, audio-noise, electrostatic fields have not yet been encountered in 400 KV DC overhead system.

Lower overhead line construction costs.

Disadvantages

No high voltage DC circuit breaker has been developed.

Development of DC systems limited to two terminal system because of the absence of DC circuit breaker.

More land use for terminal equipments siting.

The terminal equipment and the AC/DC conversion equipment is expensive. (Approximately 4 times the cost of equivalent AC terminal equipment).

Areas for Research and Development

If the potential benefits of DC systems as additions to the existing AC network are to be realized, more funding is required and research and development in the following areas deserve support:

Development of smaller, more reliable and economical conversion devices.

Solid state valve technology

Improved terminal station system design

Development of improved ground return and electrode designs

Investigation of clearances, corona effect, losses and environmental impacts of HHV DC overhead lines.

TABLE XXI

High-Voltage Direct-Current Power Transmission Projects
In Commission and Planned

Date of Commission	Line	Voltage to ground (kV)	Total Length of route (Miles)	Power Transmission (MW)
	Projects in Commission			
1954 & 1970	Gotland-Swedish Mainland - Submarine	150	61	30
1961	Cross-Channel - Submarine	±100	40	160
1965	New Zealand - O/H & Submarine	±250	382	600
1965	Japan (Frequency Changer)	2 x 125	0	300
1965	Konti-Skan - O/H & Submarine	250	107	250
1965	U.S.S.R. (Volgograd-Donbass)- O/H	±400	295	750
1967	Sardinia - Italy - O/H & Submarine	200	252	200
1968-1970	Vancouver Island - O/H & Submarine	260	43	312
1970	NW-SW Pacific Intertie - O/H	±400	846	1440
1972	New Brunswick Asynchronous Tie	2 x 80	0	320
1973-1976	Nelson River - Winnipeg - O/H	±450(1976)	600	800-1620
1973	Kingsnorth - London - U/G	±266	51	640
	Other Projects under Construction or in Design			
Const.	Carbora Bassa - O/H	±533	845	1920
Design	Zaire - O/H	±500	1116	1120
"	Skagerak - O/H & Submarine	±250	138	500
"	Hokkaido - O/H & Submarine	±250	236	300
"	Ekibastuz Center - O/H	±750	1500	6000
"	North Dakota - Minneapolis-O/H	±450	402	1000
"	Center - Duluth - O/H	±250	460	500

b. D-C Underground Transmission Cables

Little attention has been devoted to the development of DC transmission cables in the Unites States. No extruded dielectric or gas spacer calbes have been designed or used for DC systems. It has been assumed that a satisfactory AC cable will have a greater transfer capacity if used to transmit DC . In the cryogenic system it is clear that a superconducting DC cable will be superior to a superconducting AC cable since it is the system in DC which is tryly without electrical power loss. It is important that the design of DC cables be investigated and optimized for future development.

Conclusion: There are some reasons for the increasing use of underground systems because of (a) rapid growth of cities and population (b) doubling of power requirements every ten years and (c) environmental and esthetic requirements.

The evaluation of present and future possibilities for improving underground power transmission capabilities and reducing costs can be described as encouraging. The most likely application for future underground systems can be divided into two general categories (a) transmission and high voltage distribution into and within metropolitan areas and (b) as elements in long distance transmission lines in rural areas. The technology is available to uprate new installations of pipe-type cables through forced cooling or natural cooling. Compressed gas-insulated cable technology has come to commercial realization to increase underground power transmission. It is expected that further research and investigation of these methods is required.

Resistive cryogenic cables offer great promise from a theoritical point of view but a major amount of developmental work remains to be done. The economic competitiveness of this system is still uncertain even if it can be developed technologically. Superconducting cables still require extensive research and development with commercial application not likely before the late 1990's.

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