

rate of the gasifier since the excess steam must flow through the descending bed of coal being dried, pyrolyzed, and gasified. In addition, the steam reduces the efficiency of the gasifier, increases the need for heat recovery from the product gases, and increases the amount of wastewater which must be treated.

The descending bed gasifier can be designed to permit melting of the ash to slag, thereby permitting significant reduction of steam additions and increases in the processing rate. The overall result for operating in the slagging mode is a 30 to 40% reduction in investment costs for coal gasifiers and associated equipment compared to the dry Lurgi. This saving is limited to the gasifier steam and oxygen plants, gas cleanup and wastewater facilities, and not to the entire plant. The "Slagging Lurgi" has been tested in a 6-foot diameter⁽⁵⁶⁾ gasifier in the British Gas Council facilities at Westfield, Scotland.

The proposed demonstration plant by Conoco in Noble County, Ohio, for the production of SNG would be a Slagging Lurgi.

6.4.2 Fluidized Bed Gasifiers

Commercial low-pressure gasification of coal in fluidized beds has been accomplished for many years in the Winkler gasifier, but fluidized bed gasification of coal at elevated pressures is still in the pilot plant stage. Fluidized beds utilize gas movement upward through small coal and ash particles to stir and mix the particles with respect to each other without the need for the mechanical grates and stirring devices required in descending bed gasifiers.

Two major difficulties with fluidized bed gasification of coal are the tendency of caking coals to agglomerate and the need to have relatively carbon-free ash so that significant amounts of energy in the discarded ash will not be wasted. Both problems can be handled at present and additional R&D is underway to reduce costs.

The U-gas process, developed by IGT and the basis for design of a Memphis, Tennessee demonstration facility, is a major activity in

the development of single fluidized beds for elevated pressure operation. IGT has tested a 3-foot diameter unit at about 60 psi and has proposed 13-foot diameter beds operating at 100 psi for the demonstration plant. This project would produce 175 million CFD of 300 Btu gas for use by industries near Memphis, Tennessee. The City of Memphis, IGT, Foster-Wheeler, and Delta Refining Company are participants in the project.

The Westinghouse gasifier system — a fluidized bed, pressurized, ash agglomerating unit — has been operated using only one bed although it was originally designed for two, one for gasification and one for pyrolysis. Ash agglomerating gasifiers have also been tested by Battelle and Union Carbide.

Descending bed gasifiers possess the advantage of countercurrent movement of coal and gas to maximize production of methane and other hydrocarbons and to recover a portion of the heat from the gasification zone inside the gasifier. These advantages of countercurrent flow can be partially gained by using a series of fluidized beds or an entrained gasifier whose product gases enter a coal pyrolysis unit. Units of this type include the Westinghouse and Union Carbide gasifiers mentioned in the previous paragraph, plus Bi-gas, Combustion Engineering, Foster-Wheeler, CO₂ Acceptor, Hygas, Synthane and others.

6.4.3 Entrained Flow Gasifiers

Entrained flow gasifiers are the least complex means of gasifying coal. They can be thought of as a special burner in which pulverized coal, steam, and oxygen are reacted. The maximum temperature present in the flame is high, 1500°C, or higher and the reactions are very rapid.

To achieve efficient operation of the entrained flow gasifier it is desirable to recover energy from the high-temperature gas products at as high a temperature level as practicable. This usually means high pressure steam for generation of electrical power. For this reason, the equivalent of a large boiler is usually attached to the entrained

flow gasifier.

Caking coals can be readily used in the entrained flow gasifier since the pyrolysis and gasification reactions take place very quickly in the flame beyond the burner. Carbon utilization efficiency is high for entrained gasifiers, but frequently oxygen consumption is higher than for other gasifiers. Entrained flow gasifiers minimize problems with tars and phenols in subsequent processing equipment.

Two major, single stage, pressurized, entrained flow gasifiers are involved in large-scale development. The Texaco medium-Btu gasifier technology is based on their experience with gasification of petroleum residues at elevated pressures. Petroleum residues can be pumped at moderate temperatures for convenient feeding to the gasifier and contain only small amounts of ash. Coal can be fed to entrained gasifiers as a water slurry in a similar manner. This results in decreased gasifier efficiency since the water must be evaporated. Furthermore, problems with high pressure slurry pump maintenance are introduced. A 15 ton per day unit in California has been used extensively in these tests. A 150 ton per day unit began operation in West Germany in 1978. A 200 ton per day Texaco gasifier has been retrofitted onto a 225 ton per day TVA ammonia plant previously fed by natural gas. Operations began the last quarter of 1980.

DOE has concluded that the Texaco Gasifier is "commercially available" technology for use in the SRC-II demonstration plant.⁽⁵³⁾ A Texaco gasifier will also be used in the 100 megawatt combined cycle plant using medium-Btu gas planned for the Cool Water Station of Southern California Edison Company. EPRI and others are also participating in the project.

Another major elevated pressure entrained gasifier technology is the Shell-Koppers. This gasifier is based on the Koppers-Totzek low-pressure gasifier which has been operated commercially for many years. A 150 ton per day Shell Koppers gasifier was started up in November 1978 at Dutch Shell's oil refinery in Harburg, West Germany. A

prototype gasifier to process 1000 tons per day of coal is scheduled for 1985. (54)

6.4.4 Rotary Kiln Gasifiers

Allis Chalmers has investigated applying their rotary kiln technology, used commercially for iron ore pelletizing and direct reduction of iron ore, to the production of low-Btu gas from coal. Advantages for the rotating kiln process are its ability to use caking coals, including fines, and its large turn-down ratio. This research was initiated in 1971, and ground breaking for a 600 ton per day demonstration plant at Wood River, Illinois will occur in October 1980. (57) The project is also supported by several utility companies and the State of Illinois.

6.4.5 Molten Fluid Gasifiers

Coal, steam, and oxygen can be injected into a container of very hot molten fluids to be gasified. Three fluids have been tested: molten iron, sodium carbonate, and molten ash. The molten iron and sodium carbonate also act to retain sulfur so the sulfur does not have to be removed from the product gases. None of the projects are near the demonstration stage in the U.S. and it remains to be seen if they can gain an economic advantage over the gasifier technologies previously discussed.

6.4.6 In Situ Gasification

Successful development of *in situ* gasification technologies would significantly increase the amount of coal recoverable in the U.S. since many coal deposits are not amenable to mining. The concept is very simple: injection of steam and air or oxygen into a coal deposit and igniting it. Implementation of this concept will require extensive field work. Several tests are in progress, but plans for commercialization are not expected until the late 1980's. (58)

6.4.7 Catalytic Gasification

The ultimate in a simple and thermally efficient means of producing methane is to react carbon directly with water as follows:



Negligible heat is required for this reaction. It must take place at elevated temperatures but not at temperatures so high that methane is present only in low concentrations.

In operation, the simple concept of reacting carbon with water to produce methane becomes a rather complex process. A catalyst must be intimately dispersed on the coal to promote the reaction. The catalyst is relatively economical, potassium carbonate, but it still must be recovered by leaching the ash. The methane concentration in the mixture is always rather low, under 25%, so it is necessary to selectively remove the methane by cryogenic distillation and to return the carbon monoxide and hydrogen to the reaction vessel.

Exxon has tested catalytic gasification technology in a 1 ton per day PDU. It is a rather complex process but completely avoids the need for a traditional gasifier and an oxygen plant as employed in most gasification processes. Plans have been announced by Exxon to build a 100 ton/day pilot plant in the Netherlands. (59)

6.4.8 Hydrogen Production Without Gasification

Reforming of gaseous and liquid hydrocarbons has been the most convenient route to hydrogen in the recent past. As discussed above, reforming is the reaction of hydrocarbons with steam to produce hydrogen and carbon monoxide. All domestic ammonia and methanol production is dependent on reforming of natural gas or gasification of heavy oil to produce hydrogen. Some gas companies in the U.S. reformed light petroleum liquids to produce synthesis gas for production of methane in the past.

A portion of the gaseous products from direct coal liquefaction plants can be reformed to produce the needed hydrogen. This approach

was considered by Exxon in their Donor Solvent Process. In this instance, it is an economic decision whether it is better to gasify coal or liquefaction residues for hydrogen or to reform a portion of the products from the synfuel plant.

Hydrogen can also be produced directly from water instead of reacting the water with coal as in the gasification reaction. Direct production of hydrogen from water requires a tremendous energy input since the reaction is "unburning" of hydrogen; that is, all of the energy released by burning hydrogen to produce water must be returned when hydrogen is recovered from water.

Several research projects are devising techniques to accomplish this reaction by means of heat or direct solar radiation, but presently the only practical method is electrolysis of water. Generation of electricity from thermal sources is only 30% to 35% efficient, and the production of hydrogen by electrolysis requires about three times more energy than production of hydrogen by gasification of carbon. For this reason, large-scale electrolysis of water primarily for hydrogen would not be considered if coal is being burned in the same electric utility grid for the generation of electricity.

If electricity were available economically in an isolated location without connections to an electric utility grid and without a source of carbon, then the preceding objection to hydrogen by electrolysis might not apply. This location might be a grazing ocean thermal electrical generating facility. The electrolysis of brine at sea would yield caustic and chlorine as well as hydrogen. The products of a grazing ocean thermal synfuel facility, producing either synfuels or chemicals, would have to compete with these same materials produced domestically from fossil fuels or biomass.

6.5 DIRECT LIQUEFACTION

Direct liquefaction processes for the manufacture of synfuels from coal depolymerize the coal molecules and increase their hydrogen content by reaction with hydrogen. The hydrogen required for

direct liquefaction of coal is produced from coal or process by-products. For this reason, gasification technologies are also required for direct liquefaction of coal.

The final upgrading into finished gasoline and other user products utilizes technology similar to that already used to refine crude oil. These processes will not be stressed here. Emphasis will be placed on the initial reaction of hydrogen with coal and a second treatment with hydrogen when needed to produce a coal liquid amenable to nearly conventional petroleum processing.

Common terminology limits direct coal liquefaction technologies to processes which start by mixing finely crushed coal with a recycled oil and hydrogen. Liquid products may also be obtained directly from coal by pyrolysis, (Section 6.3).

The initial reaction is between the recycled oil and coal in which hydrogen is donated by the recycled oil to the coal. To the extent that reaction conditions are favorable, hydrogen then reacts with the oil to replace the hydrogen donated to the coal. The liquefied coal may react with additional hydrogen to decrease its molecular weight and remove sulfur and nitrogen molecules. There are several variants of this process.

Catalysts are necessary to increase reaction rates and to increase the yields of the desired liquid products in direct coal liquefaction processes. The manner in which the catalysts are utilized in the process provides a convenient means of distinguishing among direct coal liquefaction technologies.

The natural catalytic activity of coal ash will permit partial liquefaction without added catalysts. This is the basis of the original Solvent Refined Coal (SRC) process, now called SRC-I. By the action of hydrogen at a pressure of 120 atm and temperatures of about 450°C, coal is converted into liquid and a portion of the sulfur is removed. The unreacted coal and ash can be removed from the liquefied coal by

filtration, or solvent deashing techniques. The SRC product is then cooled into a solid product for combustion in utility boilers. Since SRC-I refined coal has a low-ash content and a substantially reduced sulfur content, it can often be utilized in boilers without provision for scrubbing flue gas and handling large quantities of ash.

Filtration of the solids from the SRC coal has proven to be a difficult mechanical problem. Two alternative solids separation techniques, Kerr McGee Critical Solvent Deashing and Lummus Anti-solvent Deashing, have been tested. Both these techniques involve adding a solvent to the mixture of coal liquids and ash produced by the SRC reaction. The solvent action promotes solids settling from the mixture. Mixing the solvent, settling the solids, and then recovering the solvent for reuse adds to the complexity of the process, but it circumvents the filtration step which has proven difficult to accomplish. The two processes differ in both the technique and in the different technologies used.

SRC-I has been tested in a 6-ton per day pilot plant in Wilsonville, Alabama, and a 50-ton per day pilot plant at Ft. Lewis, Washington. A 6,000 ton per day demonstration plant is being designed for construction in Kentucky beginning in 1981. Recent developments of the SRC-I process have been accomplished by Air Products Company, Wheelabrator-Frye, and Southern Company Services. It has been supported by EPRI and DOE.

The SRC-I product can be processed into a synthetic crude oil by an additional treatment with hydrogen, this time in the presence of a catalyst. The HRI Division of Dynallectron is installing an H-Oil hydrotreater for this purpose at the Wilsonville SRC-I PDU. The H-Oil process uses an ebullating bed of catalyst pellets. These techniques have received only limited tests, but since they rely heavily on existing petroleum refining technology, mechanical implementation is not regarded as difficult.

Initial development of the SRC process was begun in 1962 by Spencer Chemical Company, now owned by Gulf Oil Corporation. Gulf has

continued with the development of SRC-II. SRC-II produces a synthetic crude in one reaction step. The crude is sufficiently volatile so that it can be vacuum distilled away from the ash and unreacted coal, thus circumventing the difficult solids separation step. The SRC-II process recycles the product from the reactor, after hydrogen and easily volatile liquids have been separated from it, to the feed preparation stage where it is mixed with raw ground coal. This recycle stream increases the amount of coal ash in the reactor to act as a hydrogenation catalyst, and the recycled liquids are hydrocracked with additional hydrogen to become a syncrude. The SRC-II process has been tested at the same 50-ton per day Ft. Lewis, Washington pilot plant used for the SRC-I process. A 6000 ton per day demonstration plant is being designed for construction in West Virginia.

To enhance the natural catalytic reactivity of coal ash, supplemental catalysts can be intentionally added to the reaction mixture. The German World War II coal hydrogenation processes frequently added an iron catalyst to the coal. When catalysts are dispersed with the coal, they are generally used only one time because of the expense and effort in recovering them from the ash. No processes of this type are currently planned for demonstration plants, but Dow Chemical has briefly reported PDU data for their process. The unique aspect of their process is adding the catalyst to the coal oil slurry as a water-in-oil emulsion. The catalyst is dissolved in water as salt which decomposes on heating to result in very fine particles of catalyst suspended in the oil slurry. Liquid cyclones are employed to separate a large portion of the ash and unreacted coal from the catalyst so the catalyst can be partially recycled. Molybdenum, at a concentration of 100 ppm of added coal, is an effective catalyst for this purpose. Other aspects of this process resemble the SRC processes. Development of this process was begun relatively recently, 1973, and it is now being evaluated for commercialization potential by Dow. (60)

The H-Coal process is an extension of the commercially proven H-Oil process. A catalyst in the form of pellets is retained in the reactor vessel. To maintain uniform temperature and flow conditions, the

liquid inside the H-Coal reactor is continually recycled upward through the catalyst particles at a sufficient velocity to gently agitate them. This is termed an ebulated bed. The H-Coal process can be operated in a fuel oil mode, which requires a solids separation step as in the SRC-I process, or in a syncrude mode, which separates the ash by distillation as in the SRC-II process.

Operation of a pilot plant for the H-Coal process has begun in Catlettsburg, Kentucky. Ashland Synthetic Fuels and the HRI division of Dynallectron are the major operating participants in this project. Primary funding is from DOE. This plant produces either a synthetic crude oil or a boiler fuel, depending upon the mode of operation. Coal requirements are 200 tons per day in the syncrude mode or 600 tons per day in the boiler fuel mode.

The use of two or three reactors in series, without internal recycle of liquid, provides more flexibility in processing temperatures and a greater driving force to hasten the reaction of hydrogen with coal. These are the tactics used in the Lummus Clean Fuels from Coal, LCFFC, process to reduce the hydrogen consumption and reduce the production of light gases. Lummus has operated a PDU to demonstrate this process supported by DOE. (61)

Greater process flexibility can be attained if the recycle oil used to slurry the coal is catalytically hydrogenated prior to mixing it with the raw coal. The prehydrogenated oil can then donate hydrogen to the coal. In addition, the catalyst only contacts distillate oil and is not exposed to the ash and non-volatile components in the coal. This process is being developed by Exxon as the Exxon Donor Solvent (EDS) process.

In the EDS process, the residual unreacted coal and ash are fed to a fluidized bed coker/gasifier. In this device, the residue is pyrolyzed (coked in petroleum refining terms) to char, volatile liquids, and gases by contact with hot coke particles. This process achieves an additional yield of liquid product. Low Btu fuel gas is produced by

the integrated coke gasifier; hydrogen is produced by reforming light hydrocarbon gases produced in the process.

A 250-ton per day EDS pilot plant is being operated by Exxon at Baytown, Texas. It is primarily supported by Exxon and DOE.

The direct liquefaction processes have many common problems. To maximize the processing rate per dollar invested, it is usually desirable to have a maximum of solids in the slurries which are pumped among the various processing units. The major material flowing in these processes is a slurry of either raw coal, or unreacted coal and ash in oil. In general, the more concentrated these slurries are, the more economical is the process. For this reason, the slurries are very viscous and may even become solid on cooling. They are very erosive to metals, even very hard specialty metals. Heat transfer to the slurries is frequently quite slow due to their viscous nature. The various pilot plants have encountered these problems and made steps toward their solution. It is not obvious how much more effort will be required to develop commercially acceptable equipment for processing these slurries. The current demonstration and pilot plants will serve to accomplish much of this equipment development and demonstration effort.

6.6 INDIRECT LIQUEFACTION

Indirect liquefaction technologies for coal circumvent two major difficulties of direct coal liquefaction technologies; incomplete removal of sulfur from the products and mechanical difficulties in achieving efficient and economical removal of ash from the liquefied coal. These problems are avoided by converting the coal to synthesis gas, a mixture of carbon monoxide and hydrogen, in a gasifier. The synthesis gas can then be purified to the necessary level. The desired liquid fuels are then synthesized from the synthesis gas.

Two indirect liquefaction processes are being considered for near-term application — Fischer-Tropsch synthesis and synthesis of metha-

nol, which can be converted to high octane gasoline by a further catalytic process.

Fischer-Tropsch synthesis begins with gasification of coal and purification of the resulting synthesis gas as discussed in Section 6.4. The synthesis gas is reacted over an iron catalyst at a pressure of about 350 psi and temperature of 330°C. The reaction produces a large amount of heat which must be removed by careful reactor design. The traditional catalyst system inherently produces a wide range of materials ranging from methane to wax, including alcohols. For this reason, considerable subsequent refining of the Fischer-Tropsch products is required. Many specialty by-products result which supply a wide variety of market needs, but are not appropriate for large scale production.

There are opportunities to improve the products from Fischer-Tropsch synthesis by using shape selective catalysts which minimize the production of high molecular weight materials.

Large scale Fischer-Tropsch synthesis has been utilized in South Africa since 1955. Completion of Sasol III will bring the capacity to over 100,000 barrels per day of total products. Thereof, approximately 84,000 barrels per day are transportation fuels; the remainder are chemicals and by-products. The Sasol experience with Fischer-Tropsch synthesis is available in the United States through the Fluor Corporation.

The second indirect liquefaction option is the use of the fully commercial catalytic process to make methanol as the principal product. Methanol can be used as a fuel in numerous stationary and some transportation applications. Smaller size methanol-from-coal plants have been operated in the U.S. prior to the availability of cheap natural gas as a feedstock in the 1950's. Methanol can also be converted to gasoline by the M-Gasoline process, a methanol to gasoline technology developed by Mobil beginning in 1970 using their patented ZSM-5 zeolite catalyst. This catalyst is used in several other commercial

processes. The yield of high octane gasoline is about 85% of the hydrocarbons produced, if light olefins produced by the process are alkylated to produce gasoline. The operating conditions for the methanol to gasoline reactors are not severe, about 350 psi and 370°C.

In November 1979, New Zealand chose the M-Gasoline route to produce 12,500 bbl/day of gasoline from natural gas. Since the methanol to gasoline involves only clean fluids, not solids, it is possible to design the commercial fixed bed reactors based on data from a 4 barrel per day pilot plant.

There are some advantages to using a fluidized bed for the methanol to gasoline reactions since it is an exothermic reaction. A fluidized bed plant using 100 bbl/day of methanol is planned for Wesseling, West Germany, to develop the fluidized bed reactor technology. This project is largely financed by DOE, the German government, and Mobil. Operation is planned for late 1982.

6.7 COAL-OIL MIXTURES

Approximately half of the total U.S. electrical energy generation is supplied by coal, burned either directly on grates or as pulverized coal. Direct burning is the most economical and efficient method of utilizing coal for the generation of electrical energy or for supplying process heating steam. Use of coal in this fashion will certainly expand over the next several years. However, at present approximately 30% of U.S. electrical generation is supplied by oil or gas. Unfortunately, the conversion of gas or oil burning steam generating units to the use of coal is generally costly and frequently impossible. Even for units which were originally coal fired and later converted to gas or oil, a return to coal firing may be uneconomical or impossible. Two problems which frequently arise are the lack of availability, or prohibitive cost of the type of coal for which the unit was originally designed. If a coal of lower heating value, lower grindability, or higher sulphur content must be used, the unit will generally have to be substantially modified or derated

or both. (62)

In the case of units originally designed for oil or gas, the problems of converting to coal are even more severe.

Because of these problems, and in view of the high cost of conversion, a cost which frequently cannot be justified in terms of the remaining useful life of the unit, alternate solutions or partial solutions have been sought. The use of mixtures of coal and oil is one possibility.

Many of the conversion problems mentioned earlier become much simpler or disappear when the coal is mixed with oil. This is particularly true for units which were originally designed for coal. Even if a lower grade coal must be used, the pulverizers, precipitators, and ash handling equipment may be adequate for the smaller volume of coal associated with oil mixtures. In the case of units which lack room for coal storage and handling facilities, the coal-oil mixture (COM) can be prepared off-site and delivered in a fashion similar to heavy oils.

COM combustion is an old concept which has been explored for many years and a substantial background of information is available. DOE has funded research to bring this information up to date.

COM is a slurry containing oil and finely pulverized coal which can be handled and burned in much the same manner as oil. Mixtures up to 45% coal behave as Newtonian fluids and retain reasonable pumping characteristics. Mixtures of 50% COM are highly viscous and present more difficult pumping problems.

Potential problem areas are: the stability of the mixtures for extended storage; and, possible erosion and wear of pumps, nozzles, etc. Each of these concerns are resolvable with good engineering practice. Depending on the original design and on the coal-oil ratio, some modest derating of the generating plant may be necessary.

6.8 MAGNETOHYDRODYNAMICS

The maximum overall thermal efficiency of present-day conventional electric power plants is approximately 40%. A substantial improvement is not likely to occur because the materials used to fabricate the steam generator and steam turbine cannot tolerate a further increase in the steam temperature. While some gain can be expected with fuels other than coal, there is a considerable penalty in efficiency if the fuel is derived from coal. Consequently, if coal is the fuel source, other high-temperature energy conversion methods and hardware are required to achieve a significant increase in the thermal efficiency of the generating plants. Among the new technologies under consideration, the only one mentioned in the Energy Security Act of 1980 is magnetohydrodynamics (MHD). This technology has the potential capability to produce more electrical energy from the direct burning of coal than any currently available energy conversion system. Coupled to a conventional steam system (the bottoming cycle), a coal-fired MHD system (the topping cycle) promises to improve the overall thermal efficiency to 60%. In addition to enhanced fuel economy, MHD is well suited to high levels of power generation; provides an environmentally acceptable management of chemical and particulate emissions; and, reduces the net amount of thermal discharge to the atmosphere.

Electricity is produced in a conventional turbogenerator by application of the Faraday principle: The movement of a conductor through a magnetic field will induce an electric field in the conductor. By coupling the conductor to an external load, a flow of current is produced, thus supplying electrical energy to the load. In practical terms, the conductor is copper wire and motion is supplied by a steam turbine. In an MHD system, to which the electromagnetic induction principle also applies, the wire is replaced by a conducting (working) fluid and the turbine by a nozzle. The electrical energy is extracted directly from the kinetic and thermal energy of the fluid as it expands in the MHD channel through a transverse magnetic field.

To achieve an appreciable conversion of the thermal to electrical energy, it is necessary to produce a proper combination of electrical conductivity, fluid velocity, magnetic field strength, and a large channel length to pressure ratio. These variables govern the approach to MHD power generation and the basic system design. Currently, the open-cycle plasma concept using linear MHD channels is favored for MHD plants.

The necessary electrical conductivity of the working fluid (plasma) in an open-cycle MHD system is achieved by a high temperature of combustion (3000 K). This temperature can be attained by preheating the air used in combustion. Oxygen-enriched air may be used to lower required oxidizer preheat temperatures. Still higher conductivities may be achieved by seeding the plasma with materials having a low ionization potential, such as potassium salts. Both subsonic and supersonic flows of the plasma can be attained in cooled nozzles that compress the plasma and then expand it as it accelerates in the MHD channel. Diffusers are used for efficient pressure recovery at the exit of the MHD channels. Large-volume cryogenically cooled superconducting magnets are used to provide high magnetic field strengths (6 teslas).

All the basic components of a coal-fired open-cycle MHD flow train — combustor, nozzle, magnet, channel, diffuser — involve special designs that have evolved over the last decade. Other major support systems and subsystems must be incorporated in the overall MHD power plant design. Many of these are also of recent design, and others are typical of present-day steam power plants. An MHD power plant will incorporate the following units:

- coal preparation system for the receiving, pulverizing, grinding, drying, heating, thermal processing and feeding of coal
- oxidizer preparation system
- combustion chamber for burning the coal
- MHD generator, consisting of the superconducting magnet and the channel

- seed system for the preparation, injection, recovery, regeneration and transport of the seeding materials, and slag rejection
- electrical subsystems, including DC to AC converters
- pollutant removal system
- plant control system

With respect to component development, substantial advances have been made in recent years. In the combustion of coal, 20 MWT prototype units with both partial and full slagging capability, have been tested. Encouraging results have been obtained from the preliminary running of the 50 MWT channel under conditions closely simulating those anticipated in commercial plants. Predictions for a 6-tesla superconducting magnet — designed and built in the U.S. and operated in a USSR MHD facility — have been validated. Development is proceeding in the design and testing of inverters which are capable of inverting the full power of an experimental channel for over 12 hours. Progress is also being made in the development of components that make up the balance of the plant. Engineering work has begun for the design of a commercial prototype boiler of about 300-500 MWT capability.

From the technical viewpoint, considerable progress has been made during the last decade in meeting the program objectives to develop the MHD technology required for commercialization. In the U.S., facilities are under construction to validate progress, qualify design, and obtain experience. The development of critical components, along with analytical, engineering, and economic studies, appear to be within the established program cost and time schedules. Although no fundamental technical problems have been identified which would preclude ultimate commercialization of the MHD process, level and continuity of funding and economic justifications for this technology have been erratic. In view of this, and in the presence of competing coal-based technologies that are emerging concurrently, the growth pattern for an MHD-based utility industry is uncertain, although basic component technology, essential to the design of a scaled-up commercial prototype plant, could be available before 1985.

7.0 SYNFUEL COMPARISONS

It is important to compare alternative possible facilities for producing synthetic fuels. But it is equally important to recognize that comparisons of this type are intended to illustrate the wide variety of options that may be used — there is no single "best" technology nor energy resource.

A major consideration for any facility is the cost of the synfuel, especially the costs of the individual products as they enter the market to compete with fuels from existing sources. In addition, it is necessary to consider the slate of products, the status of technical development, and the environmental aspects of the alternative synfuel technologies.

7.1 SYNFUEL PRODUCTS

The U.S. energy market is a complex system of primary energy sources and numerous fuel forms. Further complicating the market is the varying degree of interchangeability of the various fuel forms. Fuel interchangeability is controlled by technical, economic, and regulatory factors and is not always bi-directional, e.g., as every automobile driver knows, the unleaded nozzle fits into a regular tank but a regular nozzle does not fit into an unleaded tank.

Obviously, an anticipated market must be identified for the products of a proposed synfuel plant. Less obvious, but equally important to the fundamental objective of reducing oil imports, it must be shown that, directly or indirectly, those products in the U.S. market will cause displacement of an equivalent amount of foreign oil. Without meeting this test, some synfuels could just displace other domestic energy supplies.

Very generally, shale oil, pyrolysis stripping of coal, direct coal liquefaction, and tar sands produce products that after upgrading resemble crude oil and can be classified as syncrude. Syncrude can be

a feedstock for an existing oil refinery, usually with some refinery modifications, and can be processed further at the syncrude plant with additional new refining equipment. Indirect liquefaction generally produces lighter liquid products that have immediate end uses in the market. Industrial gasification (low and medium-Btu) is usually restricted to industrial use in the vicinity of the synfuel plant whereas SNG (high Btu) can be used throughout the interstate pipeline system.

7.2 TECHNOLOGY COMPARISONS

Synfuel technology is best proven by operations on a commercial scale. Demonstration plants are intended to prepare for commercial operations. A pilot plant is the development step prior to a demonstration plant and a process development unit (PDU) is the step before the pilot plant. A summary of the status for each generic process is shown in Table 7.1

Table 7.1: Technology Status

<u>Process</u>	<u>PDU Successfully Operated (yr)</u>	<u>Maximum Pilot Plant Size Operated</u>	<u>Completion of Successful Pilot Plant Program</u>
Direct Liquefaction	1962	60 Tons/Day	Yes
Indirect Liquefaction	1930	Commercial	Yes
<u>Coal</u>			
Gasification:			
LBG & MBG	1950	Commercial	Yes
SNG	1961	Commercial	Yes
<u>Shale Oil</u>			
Surface Retorting	1975	7,000 B/D	Yes
Modified <u>In Situ</u>	1973	25,000 bbls	No
<u>Tar Sands</u>	before 1950	Commercial	Yes

Table 7.1 represents an over-simplification of a complex situation. The properties of coals vary widely within a given deposit and even

more between deposits in different locations. Key variables include carbon/hydrogen ratio and sulfur and ash contents for the coal. Other properties are also important, including oxygen and water content. A conversion process is designed to handle some variation in content for these and other impurities, but a coal from a completely different source could impose limitations. Another important coal property is the caking tendency characteristics of Illinois and many Eastern coals. Some gasifiers are not able to handle caking coals.

The variations in oil shales and tar sands are often greater than for coals. Synfuels from these sources must depend on site-specific processes and overall plant designs.

7.3 ECONOMIC COMPARISON

Although costs for synfuels are frequently estimated, conclusions about the relative costs of different processes are elusive. There are many reasons for this.

It is time-consuming and expensive to prepare a rigorous cost estimate for a new plant. Many estimates, therefore, are based on short-cut methods which are only approximate. Clearly, comparisons in this case cannot be precise.

A process cost estimate reflects many assumptions about parameters such as site conditions, project scope, feedstock characteristics, by-product values, technological status, inflation rates, and financial parameters. Different assumptions made by different engineering teams mean that the resulting estimates can vary significantly — even for the same process. Misleading conclusions may occur when different estimates are compared without an understanding of the assumptions upon which they are based.

A key item required to determine accurate product costs is the total capital investment involved. A high amount of competent engineering time is required to develop a good base for an accurate capital estimate.

Because of the difficulties in preparing reliable capital estimates, they are most often the weakest link in the cost estimating chain.

Site-specific factors can have an important influence in the required capital investment. Site preparation costs are influenced by variables such as geology, soils, terrain, meteorology, and hydrology. The costs of supplying water and utilities, and of constructing roads, railways, and pipelines can vary greatly from site to site. Other site related variables include the existing air and water quality levels, which affect the costs of environmental controls. Decisions about project scope, such as the choice between purchased electricity vs in-plant generation, are often used on site-specific criteria. Such differences in site conditions can affect greatly the relative costs of different projects.

The designer's choice of coal feedstock has a major influence upon project economics. Coals differ according to rank, i.e. lignite, sub-bituminous, bituminous, or anthracite. Within any specific rank, there are large variations in coal properties. Differences exist in heating value, moisture content, sulfur content, minerals, including trace elements, reactivity, and physical properties such as hardness. These differences affect the plant design, in areas such as pretreatment steps, equipment selection and sizing, thermal efficiency, ash disposal methods, coal storage facilities, environmental controls, and product slate. Design differences in such areas influence both capital investment and operating costs, and introduce substantial uncertainties when comparing process economics.

Assumptions by different plant designers about by-products and their market values are seldom uniform. Cost estimates can be greatly influenced by credits or penalties for by-products such as coal fines, sulfur, ammonia, fuel gas, tars, and oils. Different design concepts do not yield the same by-products, of the same quality, and in the same amount. Errors can result if cost comparisons ignore differences in by-product values.

Even after the capital and operating costs are estimated, there are many important financial input values which must be resolved so that the complete financial treatment can be performed for analysis of the synfuels project. For truly comprehensive analysis, the financial basis must include the following:

1. Debt/equity ratio for the project
2. Money rates for:
 - a. borrowing during construction
 - b. debt
 - c. equity return
3. Tax rates:
 - a. federal
 - b. local
4. Tax credits
5. Depreciation method and rate (project life)
6. Escalation — inflation anticipated
7. Incidental costs related to investment, insurance, overhead
8. Handling of startup and training costs
9. Working capital requirements
10. Construction time expected and expenditure rate

This list is not necessarily complete nor are the items shown in order of importance. Once the capital requirements are established for a project, a complete set of input cost data is required. In addition to the financial information above, the following are required to allow computation of a product cost:

- a) Cost for all feed materials
- b) Labor costs
- c) Utility costs
- d) Maintenance costs
- e) Product productions rate

With the many possibilities for variations in the two information lists shown above, it is easily recognized why synfuel project studies are so often completed on different bases and therefore not suitable for direct comparisons.

The importance of clearly identifying all costs with the appropriate time has become critical in the past decade. Reasonably accurate general indices are available to adjust costs from different time to a common basis. Failing to identify a cost with the applicable year and a guess-error of two years can cause a cost error of over 20%.

In view of the many factors that affect the economics of synfuels, one needs to consider a range of cases. The Department of Energy took this approach in the 1979 National Energy Plan II.⁽⁷⁾ The low end of the range reflected an optimistic interpretation of technical status and the kind of financing terms that would be available with a proven, commercial technology. The high end of the range reflected conservation assumptions appropriate for a less certain, first-of-a-kind plant.

This DOE approach recognized that the different synthetic fuel technologies do not yield products of equivalent market value. Some technologies primarily produce relatively low valued boiler fuels such as residual fuel oil or low-Btu gas; others produce a higher-valued premium fuel, such as gasoline for transportation purposes, or pipeline-quality substitute natural gas. The DOE plan, therefore, did not report fuel costs on a dollars-per-Btu basis because this would mask the differences in product values. Instead, DOE computed the uncontrolled price that crude oil would need to command to make each synthetic fuel technology competitive.

DOE made comparisons of the relative economics of synthetic fuels. Under optimistic assumptions, i.e., the low end of the ranges, liquid fuels from shale oil and methanol and synthetic gases from coal appear strongly competitive at current world oil prices, while coal liquids are less so. The DOE pointed out that liquid fuels from heavy oils and tar sands are even cheaper than any of these sources.

Although heavy oils, tar sands, and shale oils might be more viable commercially than synthetic liquids from coals, there are major geographical and environmental limitations on the former. Thus, NEP II