efficiency is implied. If the feedstock coal has a high price compared to other economic factors, the synfuel plants will be designed to be more efficient than if the coal price were relatively low. By this mechanism, an optimum efficiency is selected to give the least costly synfuel production for the prescribed economic data. Proposed ways to increase the efficiency of a particular process must be cost effective within the same economic constraints. Similarly, other processes which are theoretically more efficient must also be relizable at an acceptable cost.

6.2   PETROLEUM PRODUCTION INCLUDING HEAVY OIL

Within the Energy Security Act, the term "synthetic fuel" is defined to include heavy oil resources which are not economic to produce at present market prices. The term enhanced oil recovery (EOR) refers to any method used to recover more oil from a petroleum reservoir than would be obtained by primary and traditional recovery. Various EOR techniques are used commercially and others are potentially available at higher costs.

After a new oil reservoir has been discovered, detailed plans are made for efficient production of the oil it contains. During primary production of the oil reservoir, the major objective is the effective utilization of energy contained in the reservoir to force oil into wells so it will flow to the surface or can be pumped to the surface.

Energy to displace the oil is most often available from the pressure of a connecting water aquifier, natural gas existing above the oil, and natural gas dissolved in the oil. Two other important sources of energy in some reservoirs are movement of oil due to action of gravity, and compaction of the oil reservoir due to weight of overburden.

In general, slow production rates enable these natural sources of energy to most uniformly displace oil towards the producing wells. Usually, it is undesirable to produce gas or water since their production wastes reservoir energy which could have been employed to displace

oil. However, these objectives must be balanced by the desire of the operator to produce oil rapidly to increase the cash flow rate of the project. The major oil producing states have regulated various aspects of oil production, such as well spacing, producing rates, and gas-oil ratios, both to conserve oil and protect the interests of other leaseholders in the same oil reservoir.

Most oil reservoirs do not have sufficient natural energy to force all available oil to adjacent wells. It is necessary, therefore, to supply additional energy to the reservoir. This is commonly accomplished by injecting either water or gas into the oil reservoir. Historically, this activity was subsequent to primary production and thus is termed secondary recovery. Current reservoir engineering practice is to begin injection of water or gas into the oil reservoir prior to the exhaustion of natural sources of energy in the reservoir, both to increase oil production rates and to increase the quantity of oil ultimately recovered. Since each oil reservoir is different, the choice between gas repressuring, water flood, or a combination of both, must be made individually. The number of injection wells, their location, and rates of injection are the subjects of detailed reservoir engineering analysis. Frequently, simulation of the entire reservoir on a computer is justified to optimize details of producing the oil resevoir.

The procedures for providing additional energy to the reservoir, gas repressuring or water flooding, become ineffective after the easily dispaceable oil has been produced. At this point, new tactics are required to recover additional oil. Historically, these were termed tertiary recovery methods, now called enhanced oil recovery.

Considerable oil usually remains in the reservoir after the traditional procedure for secondary recovery. One estimate is 300 billion barrels, compared to our known producible reserves of 26.5 billion barrels.[35] If even a small percentage of this oil could be produced by new techniques, it would be a major addition to our domestic oil. This objective of producing the oil which we have already found, but cannot produce by cost effective methods, has received the attention of research personnel in all major oil companies for several decades.

In the next decade, two major methods are expected to produce most of the oil recovered by new enhanced oil recovery techniques — steam injection and miscible gas flooding. Steam injection is now producing about 300,000 bbl/day of heavy oil. Other methods of enhanced oil production are being applied including CO_2 flood, *in situ* combustion, polymer flooding and surfactant flooding. Industrial research for improvements in all methods of enhanced oil production is continuing.

An EOR project must adapt itself to the specific oil reservoir to be produced. Some EOR projects will be rather small, producing only a few hundred barrels of oil per day, while major EOR projects can be on the order of 50,000 barrels per day. A typical EOR project has a period of time, ranging from a few months to a year, in which the project is operated, but no additional oil is produced while recovery agents are injected into the reservoir. Production then rises rather rapidly to a peak, then declines. During this period of declining production, the operating costs for the project remain relatively constant. For this reason, the operating cost per barrel of oil produced increases steadily. At some point, an economic limit is reached where production costs exceed the selling price for the oil. This economic limit is applied to individual wells in the project and ultimately to the entire project. The operator can frequently choose whether to produce the entire field rapidly in a few years or to produce at a lower rate for 15 or 20 years.

The existing economic limit for a particular field or for a well in that field can be calculated accurately. This is done every day as operating decisions are made in the field to drill additional wells, to work over wells, or to abandon wells.

6.3   PYROLYSIS

Pyrolysis is the thermal decomposition of organic compounds in the absence of oxygen. Since pyrolysis technologies have developed independently for different raw materials, several synonyms for the word pyrolysis exist. The word *retorting* is normally applied to the

pyrolysis of oil shale. *Pyrolysis* and *carbonization* are common terms for thermal decomposition of coal. *Coking* is a term for thermal de-decomposition of oil and *destructive distillation* is a term for thermal decomposition of wood. Herein, the retorting of oil shale and the pyrolysis of coal are the areas of interest and the common terms used.

6.3.1 Retorting of Oil Shale

Detailed laboratory studies have found that kerogen, the primary organic material in oil shale, decomposes in two steps when heated to above $400^\circ C$ as illustrated below:

$$Kerogen \rightarrow Bitumen + Gas + Carbon$$
$$Bitumen \rightarrow Oil + Gas + Carbon$$
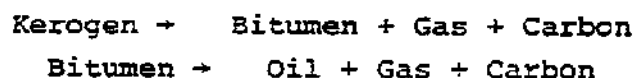
If possible, oil shale should not be heated above $600^\circ C$ during retorting, because limestone and dolomite in the oil shale mineral matter will be decomposed releasing carbon dioxide and consuming energy. Excessive temperatures may also crack the shale oil to less desirable gases. The major differences between shale oil and natural petroleum are the high nitrogen content of shale oil and its semi-solid nature at ambient temperatures, as indicated by the pour point being above $15^\circ C$. Under typical retorting conditions, the kerogen decomposes to about 65% oil, 12% gases, and 23% carbon, which remains on the spent shale. More commonly, yields from oil shale retorting processes are reported as a percent of Fischer Assay, frequently in the range of 80 to 110%. It should be stressed that percent of Fischer Assay is only a means of comparing a particular retorting technology to a standard laboratory retorting procedure. Thus, 100% of Fischer Assay is only a measure and does not imply perfection.

A critical factor in the economics of oil shale retorting is the rate of heating of the shale to retorting temperature. There are three basic mechanisms for heat transfer in oil shale retorts: external heating, circulating hot gases, and recirculating hot solids. In addition, oil shale can be retorted *in situ*.

The first method of retorting oil shale is simple and direct. Many

early retorts were based on this principle, but the rate at which heat can be transferred to the oil shale is too slow for economic large-scale retorting applications.

Circulating hot gases is more thermally efficient. The hot gases move in the opposite direction (countercurrent) to the raw shale so that as the recirculated gases are reduced in temperature, they contact even colder shale and can continue to transfer energy to the oil shale. The least complicated way to move shale through a retort is down, propelled by the force of gravity.

When oil shale moves downward, the flow of gas must be upward and it is necessary for the produced shale oil to move upward with the circulating gas. The produced shale oil must not condense on the surface of the incoming oil shale. Fortunately, this does not happen to any large extent. The shale oil tends to condense as a fog or mist in the rising gas stream and is carried out of the retort by the rising gases. The opportunity to remove shale oil as a mist was discovered and implemented as a retorting process by Bureau of Mines personnel in 1950. The retort was named the gas combustion retort, since it included provisions for producing additional heat as needed by combustion within the retort. Figure 6.3 is a simplified drawing of the retort. Injection of cold recycle gas into the bottom of the retort serves to cool the spent shale and to make energy available for retorting additional oil shale. To supply the additional energy needed to retort the oil shale, air and recycle gas are injected into the central portion of the retort by means of an internal gas distributor. The incoming oil shale is retorted by the hot combustion gases and these gases cooled by heat exchange with the incoming shale, finally exit near the top of the retort, carrying the shale oil product as a mist.

The key to effective operation of gas combustion retorts is uniform flow of gases upwards in the retort and uniform movement of oil shale down through the retort. For this reason, the mechanics of uniformly feeding and discharging shale to the internal gas distributor is a major mechanical design problem. The air and recycle gas must be

distributed in a uniform manner across the retort to avoid hot spots.
The gas distributor tends to mechanically impede downward movement
of the oil shale and may contribute to stoppage of shale movement in
a portion of the retort. To facilitate uniform movement of shale and
gas through the retort, it is necessary to remove fine material, less
than 1/4 inch in diameter, from the shale feed to the retort and to
avoid oil shale richer than 35 gallons per ton. Rich oil shale
becomes soft and plastic during retorting, thus forming agglomerates
which will not flow uniformly through the retort. A significant ob-
jective is to increase the portion of oil recovered. About 85% to
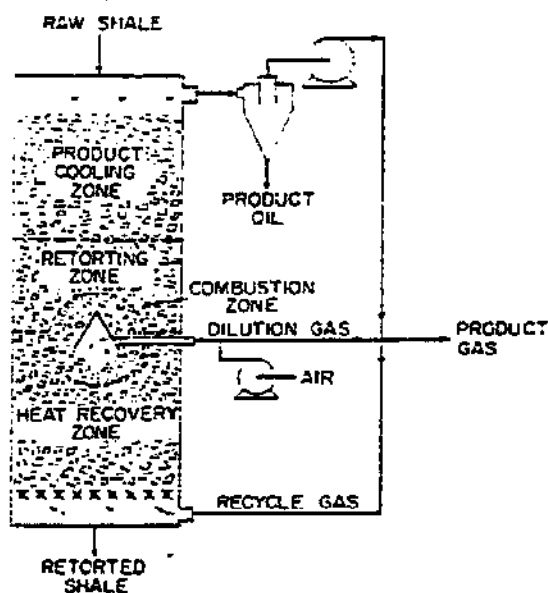90% of Fischer Assay oil is now recovered.

Figure 6.3: Diagram of First Gas Combustion Retorting Process (Ref. 36)

To increase oil yield, and for other advantages, another variation
of the gas combustion retort has been developed. In this major al-
teration of the gas combustion retort, hot gases are injected into

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the central portion of the retort instead of air and recycle gas.
This procedure allows direct control of temperature within the re-
tort. Control of internal retort temperatures offers several advan-
tages such as minimizing carbonate decomposition, increasing oil
yields, and reducing the risk of mechanical damage to the gas distri-
butor due to overheating. To achieve these advantages, a consider-
able additional investment must be made in an externally-fired fur-
nace to heat the gases before injection into the retort. Another
advantage of this modification is that the gases produced during re-
torting are not diluted by nitrogen from the air used for combustion.

Paraho Development Corporation has been responsible for continued
research on the gas combustion retort and its modification. The re-
search was supported by a group of 18 companies from 1973-1976. From
1976-1979 several contracts from the Office of Naval Research and DOE
supported the production of 75,000 barrels of shale oil for refining
into finished products to be tested by the Department of Defense.[37]
One June 13, 1980, Paraho was awarded a $4.4 million DOE contract to
design a 10,000 barrel per day modular shale plant for a location
near Vernal, Utah. Eight or more interested firms will provide an
additional $3.7 million for the project. DOE is preparing to fund,
possibly in September 1980, a $3.2 million feasibility study to ex-
pand the 10,000 bbl/day demonstration plant to 30,000 bbl/day capac-
ity. These design and feasibility studies will be completed in 1981.

The Petrosix retort being tested in Brazil is another "gas combustion"
style of retort except that it relies exclusively on hot gas injec-
tion into the central portion of the retort as the source of energy.
An 18-foot diameter retort has been under test since 1972 and 36-foot
diameter retorts are now being built. Expectations are that ten of
these retorts will be operational by 1984 producing 45,000 bbl/day
of shale oil.[38]

One company, Union Oil, has developed oil shale retorting technology
which forces the vertical column of oil shale to move upwards during
retorting, instead of relying on gravity flow downward. Moving the

oil shale upward requires mechanical force but there are several advantages. The initial obvious advantage of this procedure over the gas combustion retort is that the produced shale oil can drain downward to be recovered instead of having to leave the retort as a mist. Forcing the oil shale upwards in the retort so the product oil can be drained down during retorting was successfully demonstrated in the late 1940's prior to the invention of the gas combustion retort.

The Union retort has been developed and demonstrated over a period of 35 years. The pilot plant which was operated at rates up to 1200 tons per day had a rock pump piston diameter of 5.5 feet. A piston diameter of 10.5 feet is contemplated for the commercial scale retort.[39] In 1980, Union Oil announced commitment of $14 million to the construction of a 10,000 bbl/day retort which they expect to have in operation by late 1982. Their plans are to add four or more retorts by 1987 or 1988 to bring total production to 50,000 bbl/day. The total cost is estimated to be $1.5 billion.[40]

In another retorting process, crushed oil shale is moved in a horizontal circular path past ducts which inject cold recycle gas to cool previously retorted oil shale, hot recycle gas to retort fresh shale, and air containing gases to burn a portion of the carbon from the spent shale. This process avoids relative movement of the shale during retorting and thus minimizes the production of dust. It also allows close control of temperatures through the process. This is essential in the multi-mineral process in which the spent shale is extracted to recover aluminium after retorting. Excess temperatures would reduce the solubility of the aluminum compounds. Mechanics of the retort have been developed by Davy McKee Corporation for iron ore pelletizing and sinter cooling and demonstrated briefly in a 250 ton per day pilot plant facility.[41]

A design contract was awarded Superior Oil Co. on June 13, 1980, by DOE to design a demonstration plant for the horizontal moving bed process to produce 13,000 bbl/oil per day. DOE is providing $5.6 million and Superior is providing $1.9 million for the design and study, which

is expected to take 18 months. The total Superior process includes physical separation of nahcolite (baking soda) from the oil shale prior to retorting and leaching alumina and soda ash after retorting. The nahcolite would be marketed for scrubbing flue gas. These minerals represent a large portion of sales revenue from the process. In lower zones of Central Piceance Creek Basin, it is estimated there are reserves of 17.5 billion tons of nahcolite and 10.4 billion tons of Dawsonite from which soda ash and alumina can be produced.

Moving bed oil shale retorts can also be operated under a moderate hydrogen pressure to significantly increase both the yield of oil and the quality of the oil produced. This process, developed by Texaco in the 1960's, is known as "hydrotorting."[36] The Institute of Gas Technology has a current program for retorting oil shale in a hydrogen atmosphere. The project began as a program to gasify Western Oil shale but currently it is focusing on retorting Eastern oil shale.

The Eastern oil shales have a lower hydrogen to carbon ratio than Western oil shales; thus the oil yield is increased by retorting in the presence of hydrogen. IGT estimates that 423 billion barrels of oil could be recovered from Eastern shales by their HYTORT process.[42] Recently they received a $2.6 million contract to continue operation of their 24 ton per day process development unit (PDU), which began in 1976.

Recirculating hot solids is another approach to retorting oil shale at commercially attractive costs. The raw oil shale is mixed with very hot solids to raise the oil shale to retorting temperatures. This procedure allows shale fines to be retorted effectively, since large volumes of gases do not have to flow through the shale during retorting. Additional hardware is required to heat the recycled solids and to mix the hot solids with the raw shale. The most readily available solid to mix with raw shale for retorting is the spent shale itself. The spent shale can be directly heated by burning a portion of the residual carbon on the shale. Since the hot and cold solids are mixed together, the thermal efficiency gained by counter-flow heat transfer is not available.

The Lurgi-Ruhrgas process is representative of this approach to re-
torting of oil shale. Tests have indicated a production of up to
110% of Fischer Assay oil yield.[43] The Lurgi-Ruhrgas process has
also been applied commercially for pyrolysis of coal. In March, 1980,
American Lurgi Co. received a $4 million contract from Rio Blanco Oil
Shale for preliminary designs of a 4,400 ton per day demonstration
scale retort.[44]

Some advantages accrue to using specially prepared heat transfer media
instead of spent oil shale as the heated solids used to retort oil
shale. In the Tosco process, this heat transfer agent is 1/2-inch
alumina spheres. This special heat transfer agent can be heated to
higher temperatures than spent oil shale, does not consume thermal
energy by the decomposition of carbonates as in the case of spent
oil shale, and generates less fines. The initial concept of the
Tosco process included a mechanical contacting device which sep-
arated and moved the heat transfer solid countercurrent to the oil
shale being retorted. The heat transfer media was heated by combus-
tion of carbon in the oil shale. Twenty-five years of development
experience has resulted in a simplified process which heats the heat
transfer balls by combustion of shale gas. This process, known as
the Tosco II process, mixes the heated balls and preheated shale
together in one retorting stage, eliminating the countercurrent heat
transfer feature.

Tosco is proceeding with the development of the Sand Wash project in
Utah planned for 50,000 bbl/day of production. Exxon recently pur-
chased ARCO's 60% interest in the Colony Development project near
Grand Valley, Colorado. Tosco owns the other 40% of this project.
Many of the necessary permits for the project have been obtained, so
it could be started rather quickly.

In situ retorting has much the same problems and objectives as surface
retorting — efficient heat transfer to the oil shale and then gather-
ing the retorted oil. The difference results from the fact that sur-
face retorts are expensive, complex mechanical devices; hence, the

processing rate of oil shale through the surface retort must be large
to justify the investment in the retort. In contrast, in *in situ*
retorting, the "retort" is used only one time. In this case, maximum
retorting rates will not necessarily correspond to the most economic
operation.

Idealistically, shale oil could be produced using conventional wells.
The least complex approach is to place heaters in wells to retort the
adjacent oil shale. This approach fails for two reasons; heat trans-
fer rates are too slow, and the retorted shale oil must flow back
into the hot wellbore where it is coked (pyrolyzed), thereby greatly
reducing the oil yield. These limitations can be partially overcome
by using two or more wells. The wells must be connected by natural
or artificial fractures, since most oil shale has no permeability.
Flow of hot gases through the connecting fractures provides a tre-
mendous increase in heat transfer area relative to heat transfer
from a single wellbore, but heat must still be transferred by conduc-
tion through a considerable thickness of retorted oil shale if a sig-
nificant amount of oil shale adjacent to the fracture is to be re-
torted. In addition, unless the fracture in the oil shale is propped
open, thermal expansion and softening of the shale during retoring
may act to close the fracture. For these reasons, there is little
optimism for a generally useful technique for true *in situ* retorting
oil shale. This idealistic approach has been termed true *in situ*
production of shale oil.

One theoretical route to circumventing the heat transfer constraints
on true *in situ* oil shale retorting processes is to generate the re-
quired heat within the shale being retorted. Radio frequency heating
of the oil shale may generate the required temperature withing the
shale being retorted. This option is being field tested by the Ray-
theon Company which began the research seven years ago. Texaco is
participating in the field test on their property.[45] The Illinois
Institute of Technology Research Institute has received a $1.6 million
contract for radio frequency heating of oil shale. Cost, efficiency
and large-scale operability remain to be demonstrated.

An opportunity for true *in situ* oil shale retorting exists in the leached zone oil shale deposits where there is significant matrix permeability as channels were formed when salts were leached from the shale. In the 1960's, Equity Oil Company tested injection of hot methane and saturated steam into this zone for retorting. Beginning in 1977, DOE has supported this project to inject super-heated steam as the source of energy to retort the shale. Steam injection began in late 1979 and will continue through 1981.[46]

The inherent difficulty in accomplishing true *in situ* recovery of shale oil has turned attention to modified *in situ* retorting. In this approach the oil shale is reduced to broken rubble so that hot gases and/or air can be circulated through it for retorting. To provide void spaces about the broken oil shale fragments, it is necessary to either mine a portion of the oil shale or to lift up the overlying rocks to make the void space.

At shallow depths, conventional explosives can serve to slightly lift the overburden and produce rubbled oil shale. Geokinetics, Incorporated has developed this technique since 1973, and DOE has cost shared in this investigation since 1976. About 50% of the Fischer Assay oil yield has been obtained using this technique. Work is planned to continue through September 1981. This technique might permit recovery of 6 billion barrels oil equivalent from thin, shallow oil shale deposits.[47]

A direct and simple way to prepare oil shale for *in situ* retorting is to mine a portion of the oil shale, then use explosives to break additional oil shale into the void created by mining. In thick oil shale deposits, this is most conveniently accomplished by mining a room in the lowest portion of the oil shale formation and then placing explosives in the oil shale above the mined room. When the explosives are detonated, broken oil shale falls into the room to create a vertical *in situ* oil shale retort.

Retorting is accomplished by injecting a mixture of air and recycled

gas into the top of the retort to produce the sequence of zones shown
in Figure 6.4. Many oil shale deposits are thick enough to permit
formation of vertical retorts, but in some thin formations horizontal
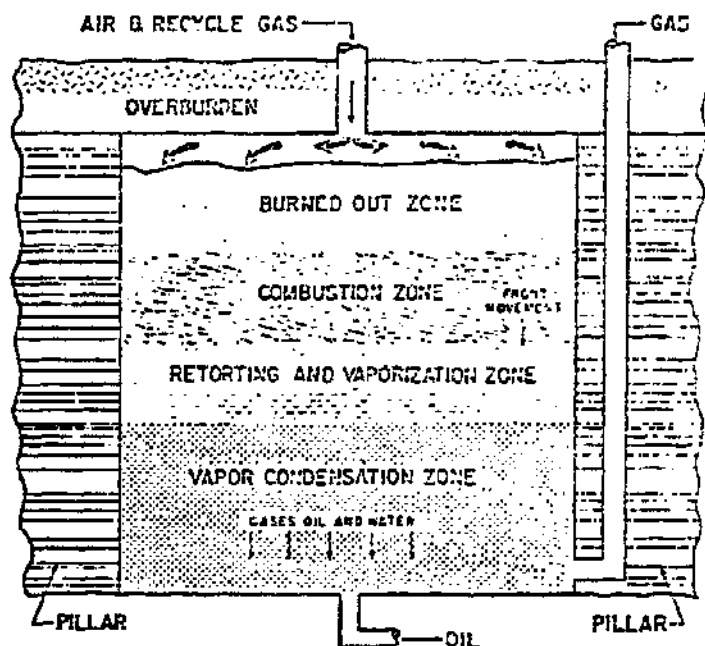retorts would be required for modified *in situ* oil shale retorting.

Figure 6.4:   In Situ Shale Retorting   (Ref.48)

Occidental Petroleum has completed six tests of vertical *in situ*
retorts since 1972. Retorting of the sixth retort having a design
porosity of 23% was completed in July 1979, with the production of
about 55,000 barrels of shale oil. This amount of oil was equivalent
to producing 40 to 45% of the Fischer Assay oil contained in the
retort. A portion of the roof of this retort failed during operation
which created problems for the operation and contributed to the rela-
tively low oil yield. DOE and Occidental are jointly supporting two
additional retorts at the De Beque, Colorado location.

Occidental Petroleum and Tenneco are developing the mine necessary
for commercial modified *in situ* shale oil production at the Colorado

C-b lease. Shaft sinking began in September 1977 and the first two retorts are to be fired in 1984. Full production of 55,000 bbl/day is expected in 1986.[49]

On the Colorado C-a lease, Rio Blanco Oil Shale Company, jointly owned by Gulf and AMOCO, is proceeding to develop modified *in situ* retorts. They are planning on a rather large porosity, 40%, to insure effective retorting and acceptable oil yields. The first experimental retort was "rubbleized" on May 8, 1980. The target date for producing 76,000 bbl/day of shale oil is 1987.[44]

The Multi Mineral Corporation proposes modified *in situ* retorting of oil shale in the saline zone followed by leaching to recover sodium carbonate and alumina from the retorted oil shale. Prior to retorting *in situ*, the broken oil shale would be screened. The resulting nahcolite would be sold as an agent for dry flue gas scrubbing and the fine oil shale removed for retorting on the surface. By removing the oil shale fines, the efficiency of *in situ* retorting would be improved. Multi Mineral Corporation is now conducting mining experiments at the Bureau of Mines' Horse Draw Research Facility.[50]

6.3.2 Pyrolysis of Coal

Coal can be pyrolyzed to produce liquid synfuels in a manner similar to that described in the previous section for pyrolysis of oil shale. In addition, the residual from a simple coal pyrolysis plant would be a char which can be burned for boiler fuel in appropriate measures are taken to control sulfur emissions.

Typically, a high volatile (40%) coal could produce a barrel of syncrude and 0.6 tons of char. Thus, instead of 10,000 tons per day of high volatile coal being supplied to a 1000 megawatt electric power plant, 16,000 tons per day supplied to a coal pyrolysis plant would provide sufficient char for the power plant (designed to burn char) plus 16,000 barrels of coal pyrolysis liquids which can be converted to syncrude.

Pyrolysis oils and tars require hydrotreating, as do the raw liquids from direct coal liquefaction processes, to yield useful, stable fuels. The capital and energy costs of generating the required hydrogen are not insignificant for either pyrolysis or direct liquefaction. Starting with a given quantity of coal, pyrolysis requires less hydrogen but produces a smaller quantity of liquid. Further study of the costs and hydrogen requirements is needed before reliable conclusions can be drawn about the relative merits of pyrolysis and direct liquefaction.

Coal pyrolysis technologies are divided into simple pyrolysis and hydropyrolysis. Simple pyrolysis is accomplished by heating coal at near atmospheric pressure. Hydropyrolysis gives increased yields of liquid and gaseous products by pyrolyzing the coal in the presence of hydrogen at elevated pressure. These increased yields are attained at the cost of having to build and operate a complex high-pressure processing plant.

Simple coal pyrolysis technologies of most commercial interest can be divided into two groups: those which use mechanical devices to mix hot solids with raw coal for pyrolysis; and, those which use a gas stream to mix raw coal with hot solids either in an entrained bed or a fluidized bed.

The oil shale retorts which circulate hot solids can also be used for coal pyrolysis. These retorts are Tosco II, which is called Toscoal when applied to coal, and Lurgi-Ruhrgas which was originally developed for coal and subsequently applied to oil shale.

A 1600 ton per day Lurgi-Ruhrgas retort operated in Lubavac, Yugoslavia on predried lignite from 1963 to 1968. A 900 ton per day plant was operated in Lincolnshire, England in 1978-1979. Operation ceased when the entire steel facility was closed down. In both of these cases the product char was used for the production of coke, not boiler fuel. A new one ton per hour pilot plant is in operation in Frankfurt for the Lurgi-Ruhrgas process.

The Toscoal process differs from the Tosco II oil shale retort in that
it may be necessary to preoxidize the coal in a fluidized bed to pre-
vent caking prior to adding it to the retort. Another option involves
fractionation of the coal pyrolysis liquids with the volatile portion
being considered product and the non-distillable portion being re-
turned to the retort. When operated in this mode, the pyrolysis ves-
sel is also utilized as a coker to upgrade the final liquid product.
Tosco has made limited tests of coal in its small pilot plant. Much
of their larger-scale hardware development for oil shale retorting
can be directly applied to pyrolysis of coal.

Entrained or fluidized beds can be used to rapidly mix hot coal char
with the raw coal to be pyrolyzed. A series of fluidized beds permits
more efficient heat utilization, and minimizes caking problems with
the coal. The COED process uses this technique. Originally, this pro-
cess was planned to produce char for combustion in utility boilers,
but now it is a part of the COGAS process where the char is gasified
for production of SNG. This technology is being designed by the Il-
linois Coal Gasification Group for a demonstration plant in Perry
County, Illinois. It will produce 1400 bbl/day of the equivalent of
No. 2 fuel oil as well as 24 million CFD of SNG. [51]

Many other coal pyrolysis processes have been proposed and tested. As
one example, a single fluidized or entrained bed is employed to which
sufficient air is added to produce the required heat for pyrolysis.
Raw coal is added to this fluidized or entrained bed and char with-
drawn. The pyrolysis liquids are condensed from the exiting gas stream
This simple process suffers reduced liquid yields and the product gas
is diluted with nitrogen and carbon dioxide. However, the advantage
is the simplicity of the process in small installations. A prototype
pyrolyzer of this type, the Parry Process, was installed by Texas
Power and Light at Rockdale, Texas in 1953. Its operation was suc-
cessful, but at that time there was no profitable market for the coal
pyrolysis liquids.

Hydropyrolysis significantly increases the yield of liquid products. At very high temperatures, pressures and residence times, the char is reacted with hydrogen and the primary product is methane. This process, termed hydrogasification, is discussed further in Section 6.4.

Several processes for hydropyrolysis of coal are being tested, but none yet at the demonstration scale. Two processes rely on very rapid contact with hot hydrogen, the Riser Cracking Process of IGT, and the application of rocket engine technology to the reaction of coal with hydrogen, being investigated by Rockwell International and Cities Service. Other processes utilize a fluidized bed for the reaction of coal with hydrogen. These processes are represented by research activities of Union Carbide, U.S. Steel, Oak Ridge National Laboratory, and Brookhaven National Laboratory. Catalysts can significantly improve liquid yields during hydropyrolysis. These processes have not yet been tested on a pilot plant scale. Adjusting the operating conditions of hydropyrolysis processes provides great flexibility in selecting the product mix to be produced — liquid, gas, and char. The liquids may be premium quality aromatic materials. The problems of feeding coal into the high pressure reaction vessel, of producing hydrogen, and preheating the hydrogen to reaction conditions are features of these processes that add to their cost when compared to simple pyrolysis of coal.

The char product from coal pyrolysis processes must be burned in utility boilers to take full advantage of the efficiency and simplicity offered by coal pyrolysis. This can be accomplished either by leaving sufficient volatile matter in the char to permit burning in the usual manner or by designing the boiler to accept char. Chars vary widely in reactivity. Thus, it will be necessary to coordinate boiler design modification with char production. Fluidized bed combustion is an effective means of consuming pyrolysis chars, and gasification is also possible.

6.4 GASIFICATION

Gasification is the process whereby solid organic materials are converted to combustible gases. Coal is the major feedstock for gasification, but biomass, peat and oil shale can be gasified with many of the same technologies.

Gasification of coal involves basically the direct reaction between steam and carbon: $C + H_2O \rightarrow CO + H_2$. This reaction occurs at a significant rate only at very high temperatures, $900^{\circ}C$ and above. The amount of energy which must be supplied to the reaction while it is occurring is quite large, 4,900 Btu/lb of carbon reacted. The most common means of supplying this energy is by burning a portion of the carbon.

If air is utilized as the source of oxygen, the product gases from the gasifier are diluted with inert nitrogen. The product is low-Btu gas which can be used as a fuel for furnaces, gas turbines, and internal combustion engines.

For most other applications, it is desirable to avoid dilution with nitrogen. Since it is more economical to separate oxygen from the nitrogen present in air than to separate the nitrogen from the gasifier product gases, most gasifier technologies for higher Btu gases use oxygen rather than air. To produce even higher heating value in the product, the hydrogen and carbon monoxide can be reacted in the presence of a catalyst to form methane: $3H_2 + CO \rightarrow CH_4 + H_2O$. The water formed in this reaction is easily removed.

The products from coal gasification include many compounds in addition to the desired hydrogen, carbon monoxide, and methane indicated in the chemical reactions. Since gasification is a high-temperature reaction, the coal will be pyrolyzed while it is being heated to the required gasification temperature. These pyrolysis products are a variety of gaseous and liquid hydrocarbons. One of the major decisions

in the selection of gasifier types is the choice between saving these pyrolysis products for synthetic fuels or intentionally reacting them with steam and reforming them to produce increased amounts of carbon monoxide and hydrogen. Frequently, the reforming of pyrolysis products is not 100% complete. Tars remain in the product gases from the gasifier to foul heat exchange surfaces, and water soluble organic compounds such as phenols contaminate the water condensed from the gasifier products.

Coal contains heteroatoms — sulfur, nitrogen, oxygen — and ash, in addition to the useful elements of hydrogen and carbon. These materials will appear in the gasifier products. The sulfur appears predominately as hydrogen sulfide, which can be scrubbed from the gasifier product gases with known technology, and similarly for nitrogen, which appears as ammonia, for the high pressure modern processes. The oxygen present in coal serves to reduce the energy content of the coal even though it does not produce pollutants.

Most of the coal ash is readily removed from the product gases. Frequently, however, sufficient fine particulates remain in the gasifier products to foul and erode subsequent heat exchangers and expansion turbines. There is continuing research and development to overcome these problems with the particular processes. An effective way to improve the performance of gasifiers is to increase the pressure at which they operate. One major advantage of high pressure operation is increased capacity for both the gasifier and subsequent process equipment.

The advantages for operation of gasifiers at elevated pressures are sufficient to cause most new gasifier technologies to operate at pressures in the range of 300 to 1500 psi. High pressure operation has several significant difficulties. One of these is feeding of solid coal into the gasifier. The hardware and techniques for processing coal and process streams at high pressures are being developed. Some gasifiers operate most effectively at high temperatures approaching 1600°C. These extreme temperatures also require improved technology and materials of construction.

In selecting a gasifier technology, both the coal which is available and the use of the produced gases must be considered. The major consideration regarding coal types pertains to their tendency to become soft and plastic when being heated to the required gasification temperature. This is the same caking phenomenon encountered during coal pyrolysis. Generally, Eastern coals have a greater tendency to cake than Western coals. For this reason, selecting and developing gasifier technologies has a geographical component in addition to engineering and economic aspects.

Gasifiers are generally classified by their product as low-Btu, medium-Btu and high-Btu. Low-Btu gas, with an energy content below 150 Btu per cubic foot, is the product of air blown gasifiers and thus has a large quantity of inert nitrogen. Medium-Btu gas, with an energy content up to 400 Btu cubic foot, is the product of oxygen blown gasifiers and thus contains less inert nitrogen. High-Btu gas, with an energy content on the order of 1000 Btu per cubic foot, is primarily methane and thus, essentially the same as natural gas. Low- and medium-Btu gas, often referred to as industrial fuel gas, will also probably find extensive application as the front end of combined cycle electric power generation plants. High-Btu gas, also known as synthetic natural gas (SNG), is made by further processing of medium-Btu gas.

Some 40 different gasifier technologies can be identified. Here we will focus on those few technologies of most interest to the large-scale production of synfuels and which are representative of the full spectrum of possible technologies of greatest interest to commercial and near commercial gasifiers.

6.4.1 Moving Bed Gasifiers

Moving bed gasifiers are the result of continued development of gasifier technology which began over 100 years ago. Coal moves downward through the gasifier and steam and oxygen or air are injected at the bottom. The oxidation and gasification reactions occur in the lower portion of the gasifier. The resulting hot product gases flow up

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through the raw coal to pyrolyze and dry the coal. The countercurrent movement of coal with respect to hot gases provides the opportunity for increased efficiency in that the coal pyrolysis zone is separate from the gasification zone so the pyrolysis products can be saved for use as synfuels. The hot gases from the gasification zone are partially cooled inside the retort as they dry, preheat, and pyrolyze the coal which reduces the need for waste heat boilers external to the gasifier.

Countercurrent flow has advantages, but adds several complexities to gasifier design and operation. Moving bed gasifiers can not operate on strongly caking coals. These coals soften and deform when heated in the gasifier, thereby causing channeling of gas flow and impeding movement. For this reason many Eastern coals can not be employed in large commercial moving bed gasifiers. Even weakly caking coals may cause some difficulty in the operation of the gasifier. Generally the particular coal must be tested in the particular gasifier being considered to plan confidently for commercial scale operation. To maintain uniform gas flow through the coal bed in the gasifier it is necessary to remove fines from the coal being gasified. These fines can normally be burned in a conventional boiler so they are not wasted. To achieve uniform movement of coal through the gasifier a rather complex grate is required, which may also serve to agitate the gasification zone.

A significant disadvantage of moving bed gasifiers is that they cannot be scaled to very large sizes due to the dynamics of gas flow through the coal being gasified and the mechanical devices required to discharge and stir the coal. For this reason, large synfuel plants using moving bed gasifiers must install a multiplicity of gasifiers (and associated piping and controls). The economies of large-scale operation are reduced by having to install many duplicate items of equipment instead of three or four large gasifiers. Gases from moving bed gasifiers frequently contain large amounts of tar which complicates downstream processing.

Many small low-pressure moving bed gasifiers are available, but only
one firm has developed a moderate pressure version of the moving bed
gasifier for synfuel plants. The Lurgi gasifier has about a 12-foot
inside diameter and can gasify about 800 tons of coal per day. A
sketch of this basic gasifier is shown in Figure 6.5. Lurgi gasifiers
are employed in the Sasol plants and in other operations around the
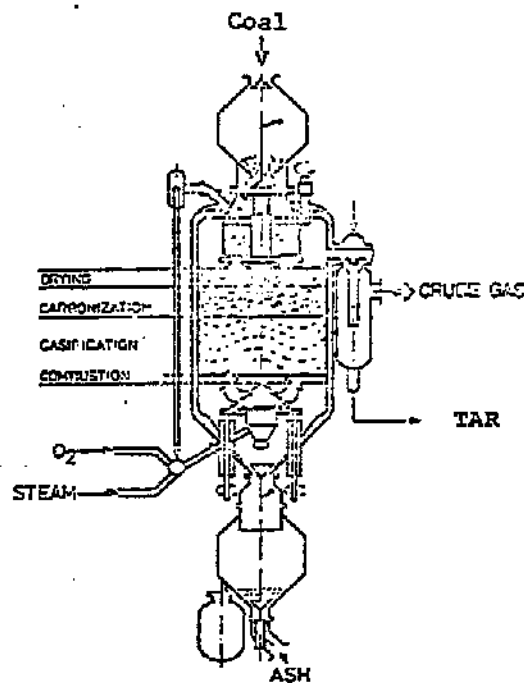world. They will be used at the Great Plains SNG plant.

Figure 6.5: Lurgi Gasifier [Ref.55]

The Lurgi gasifier discharges coal ash and unconsumed carbon as dry
material, meaning that the ash has not been melted into slag. To
avoid melting of the ash it is necessary to carefully limit tempera-
tures in the combustion zone at the bottom of the gasifier. This con-
trol of temperature is achieved by injecting additional steam into
the gasifier.

A major liability of this excess steam is that it limits the processin