SECTION 6
ENVIRONMENTAL

5.4 FISCHER-TROPSCH BASED PROCESS

5.4.1 DEVELOPMENT STATUS

Development of Fischer-Tropsch technology by Drs. Fischer and Tropsch in Germany during the 1920s led to construction of the first commercial plant in 1936. In 1939, nine plants existed in Germany with a total rated capacity of about 750,000 mtpy of liquids.

SASOL I in the Republic of South Africa is a Fischer-Tropsch plant that is reported to have produced and processed in excess of 8.5 million standard cubic meters per day of syngas and has been in operation since 1955. A program is now under way to construct SASOL II which will be on the order of 4 to 5 times larger and was scheduled to begin operation in 1980.

Fischer-Tropsch chemistry is long established and proven. There is an incentive to develop plant designs with increased efficiency and improved economics. The Pittsburgh Energy Research Center (PERC) of DOE, the U. S. Bureau of Mines, and its predecessor R&D Activity Under has investigated the use of flame sprayed catalysts for use in Fischer-Tropsch and methanation conversions over a 15-year period. A conceptual design has indicated that this system has potential advantages.[5] PERC is now initiating a small scale pilot plant test program to further investigate this method of reactor design and catalysis to determine if the potential advantages can be achieved.

5.4.2 DATA SOURCES AND FIXED CAPITAL INVESTMENT BASES

The data for the Fischer-Tropsch coal conversion process and its yields were taken from a report prepared by Parsons for ERDA.[5] This report also supplied the bases for the fixed capital investment estimate. The coal conversion units shown in the block flow diagram also came from this report.

5.4.3 PROCESS DESCRIPTION

The Fischer-Tropsch (F-T) process is shown schematically in the block flow diagram designated as Drawing R-04-FS-1.

Here the prepared coal is gasified in two-stage, entrained, slagging-type gasifiers at about 470 psig. The product gas, consisting primarily of a mixture of carbon monixide and hydrogen (syngas), is cleaned to remove particulates by scrubbers and electrostatic precipitators. Part of the syngas is then sent to an isothermal, sour shift conversion unit to adjust the H_2 to CO ratio to that required for the F-T synthesis reactor. The clean, shifted syngas is then treated in a selective acid gas removal unit to remove CO_2 and H_2S. The syngas sulfur content is then reduced to 0.05 ppm by zinc oxide/cobalt-molybdenum guard reactors before entering the synthesis reactors. The F-T reactors are extended surface (finned-tube) heat exchangers with a flame-sprayed iron oxide catalyst deposited on the outside surface. The exothermic reaction is controlled by the generation of high-pressure steam in the tubes; the ratio of cold recycle gas to fresh feed syngas is 1.5:1. The reactor operates at about $600^{\circ}F$ and 400 psig.

Methane rich gases (C_2 and lighter), containing some unreacted CO and H_2, are separated from the F-T liquids and sent to the methanation unit to produce SNG.

The liquids produced in the F-T synthesis step, which are essentially sulfur free, are separated in the liquid product recovery unit into C_3/C_4, C_5-$400^{\circ}F$ and $400^{\circ}F$-plus fractions.

The $400^{\circ}F$-plus liquid, which is highly paraffinic, is sent to the catalytic cracking unit to reduce the pour point. Heavy cycle oil, after fractionation, is sold as low-sulfur residual fuel oil; light cycle oil, after hydrotreating to saturate the liquids in order to reduce the tendency to form gum, is sold as low sulfur No. 2 fuel oil; light and heavy catcracked gasoline are sent to gasoline blending. The propylene and butylene produced by the catalytic cracking unit are combined with the propane and butane stream from F-T synthesis; this stream is debutanized and then catalytically polymerized. Polymer gasoline is sent to gasoline blending. The propane and butane from catalytic polymerization are fractionated to produce propane for use in SNG and butane for LPG and gasoline blending.

The C_5 - 400°F naphtha, which is paraffinic and has a low octane number, is hydrotreated and catalytically reformed to produce a high octane C_5-plus reformate and sent to gasoline blending.

The F-T synthesis unit produces a condensate stream which contains oxygenates, such as alcohols, aldehydes, ketones, and organic acids. plus water. The alcohol is separated in the chemical recovery unit from the organic acid and water stream.

The plant is a self-contained facility producing all of its own power, steam, and fuel gas. High pressure steam, which is generated in the process gasification unit, is used for plant steam requirements and to generate electricity for the plant power requirements. Significant quantities of high pressure steam are also produced in the shift conversion, F-T synthesis, and methanation units.

5.4.4 ASSESSMENT OF PROCESSING OTHER COALS

Table 5-3 compares gasification yields from several coals;[2] these in turn largely determine the impact on the F-T process.

The data indicate that for a constant quantity of syngas (H_2+CO) feed to the F-T synthesis step, the Eastern Coal Province coal and oxygen requirements would be about 9% and 5% less, respectively, than the Interior Coal Province coal. Therefore, the capital cost should decrease slightly since the coal preparation area and the oxygen plant would be smaller. There should be little change in plant thermal efficiency since the decreased coal feed rate is offset by the higher HHV of the Eastern coal.

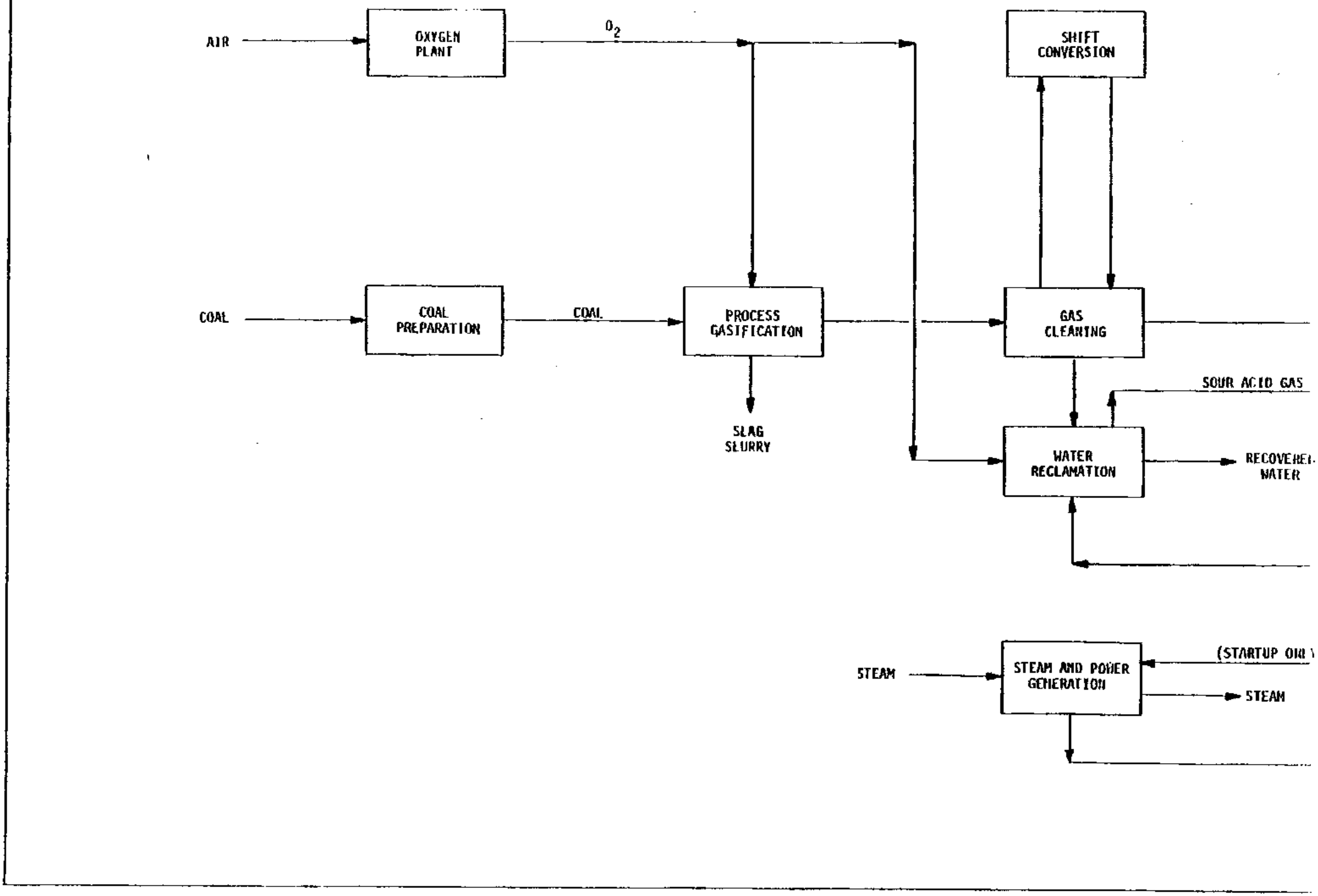
The data indicate, however, that the Rocky Mountain Coal Province coal and oxygen feed rates would each be about 10% greater than for the Interior case to produce the same quantity of syngas. On this basis, the capital cost would increase slightly and the thermal efficiency would remain essentially unchanged since the lower HHV of the Rocky Mountain coal would offset the increased coal feed rate.

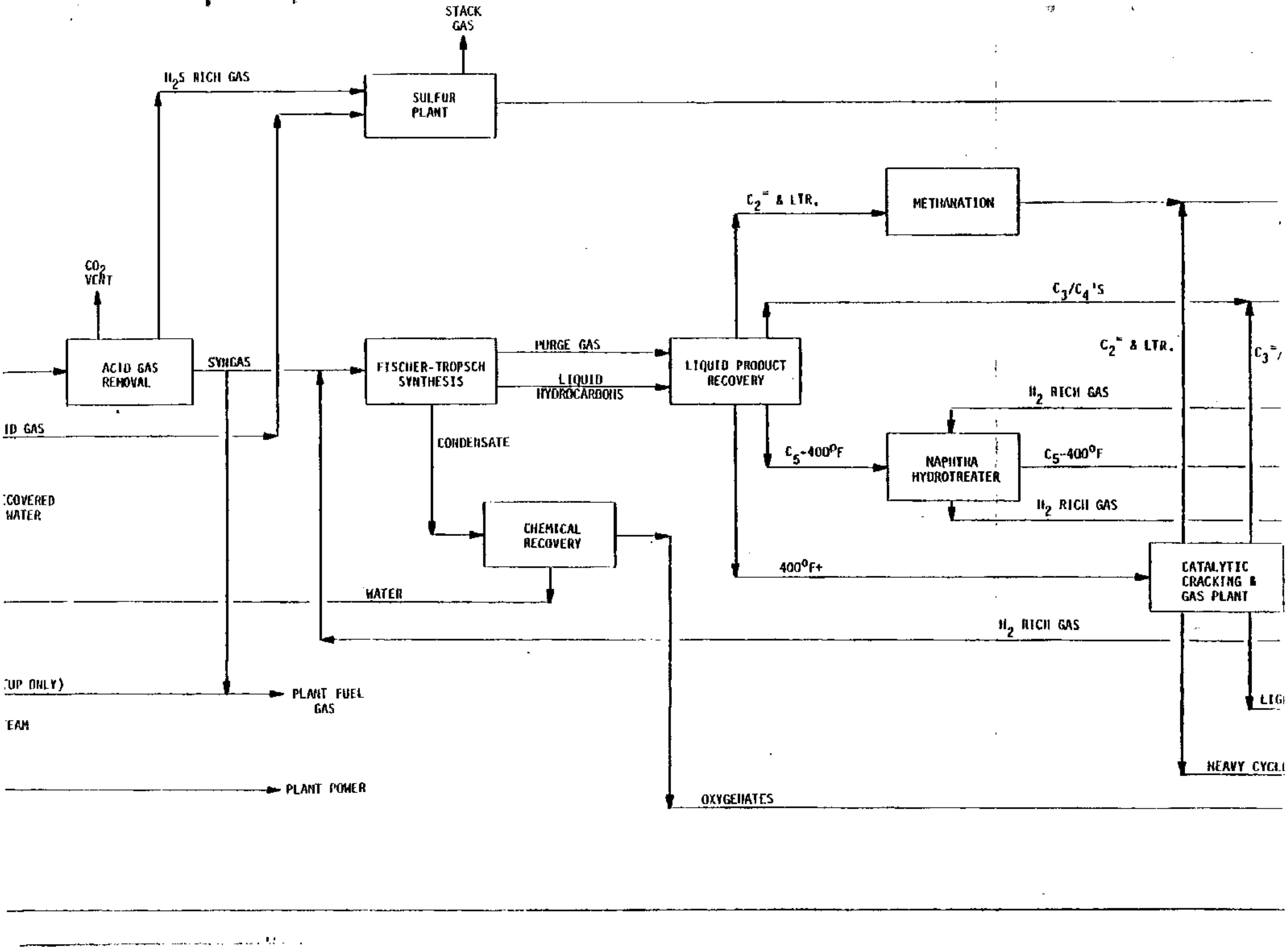
However, the Rocky Mountain Coal Province run-of-mine-coal has a water content of approximately 25% and an ash content of only about 6%. Therefore, the coal preparation facilities would be deleted since the ash content is sufficiently low; however, extensive drying facilities would be required to reduce the water content to 2.7%. Thus, the net change in processing Rocky Mountain coal would be a decrease in thermal efficiency and an increase in fixed capital cost. The higher capital cost is expected to be offset by the significantly lower coal cost than the Eastern and Interior coals.

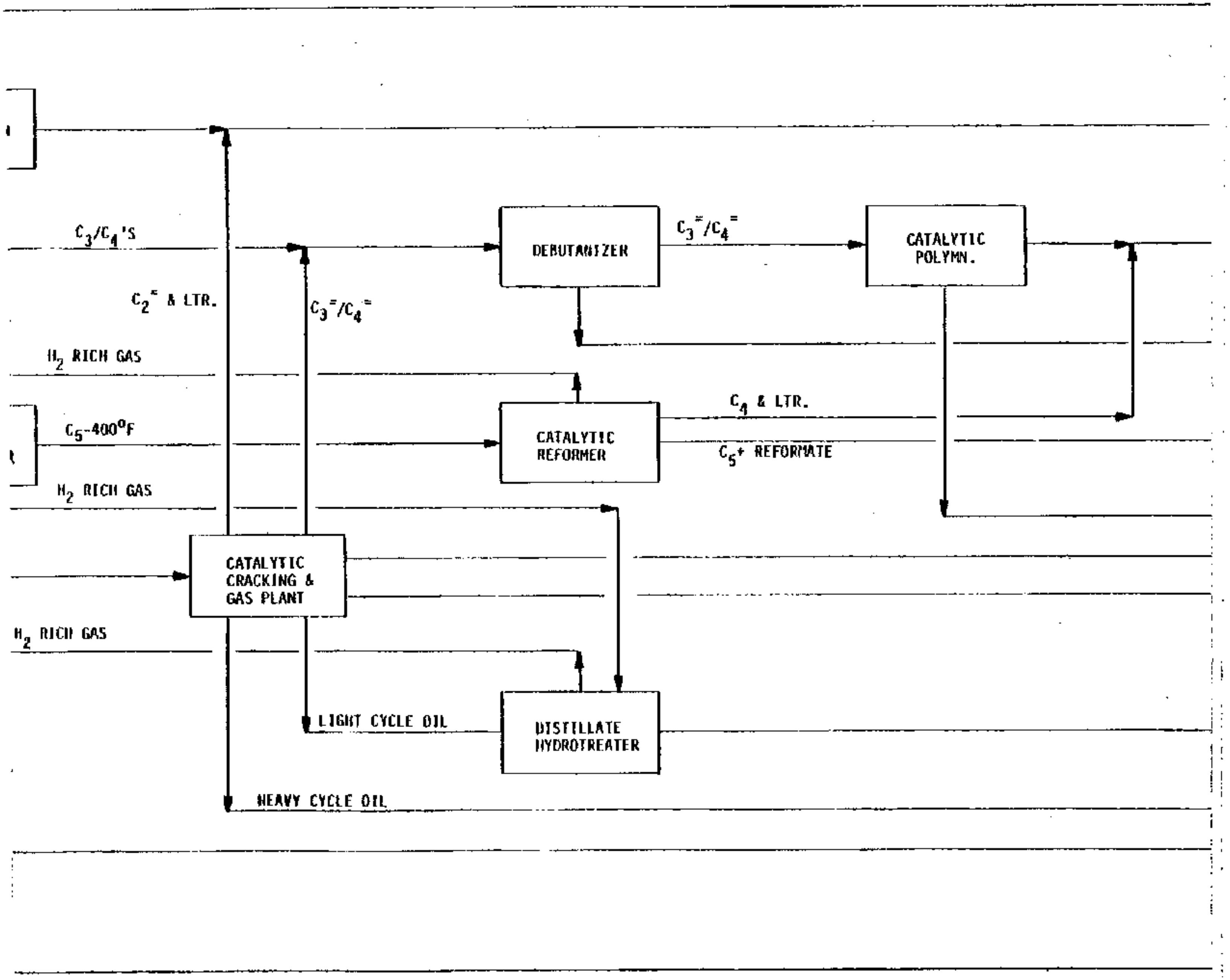
Table 5-3 - Gasifier Yields For Several Coals

Item	Interior Coal Province	Eastern Coal Province	Rocky Mountain Coal Province
Coal Proximate Analysis[2] (Wt %)			
Moisture	2.7	2.7	2.7
Ash	8.0	8.0	8.0
Volatile Matter	38.1	31.8	44.2
Fixed Carbon	51.2	57.5	45.1
	100.0	100.0	100.0
HHV, Btu/lb	12,425	13,590	11,211
Coal Ultimate Analysis[2] (Wt %)			
Carbon	70.1	75.7	66.3
Hydrogen	4.8	4.8	4.7
Nitrogen	1.4	1.6	1.0
Sulfur	3.9	1.6	0.8
Oxygen	9.1	5.6	16.5
Moisture	2.7	2.7	2.7
Ash	8.0	8.0	8.0
	100.0	100.0	100.0
Gasifier Gas, Volume % (Dry)[a]			
Hydrogen, H_2	40.8	41.6	39.9
Nitrogen, N_2	0.9	0.9	0.8
Carbon Monoxide, CO	44.9	46.2	43.6
Carbon Dioxide, CO_2	11.6	10.3	14.8
Hydrogen Sulfide, H_2S	1.2	0.4	0.3
Carbon Oxysulfide, COS	TR	TR	TR
Methane, CH_4	0.6	0.6	0.6
	100.0	100.0	100.0
Relative Rates for Constant (H_2+CO) Production			
Coal Feed	1	0.91	1.13
Oxygen Feed	1	0.95	1.09

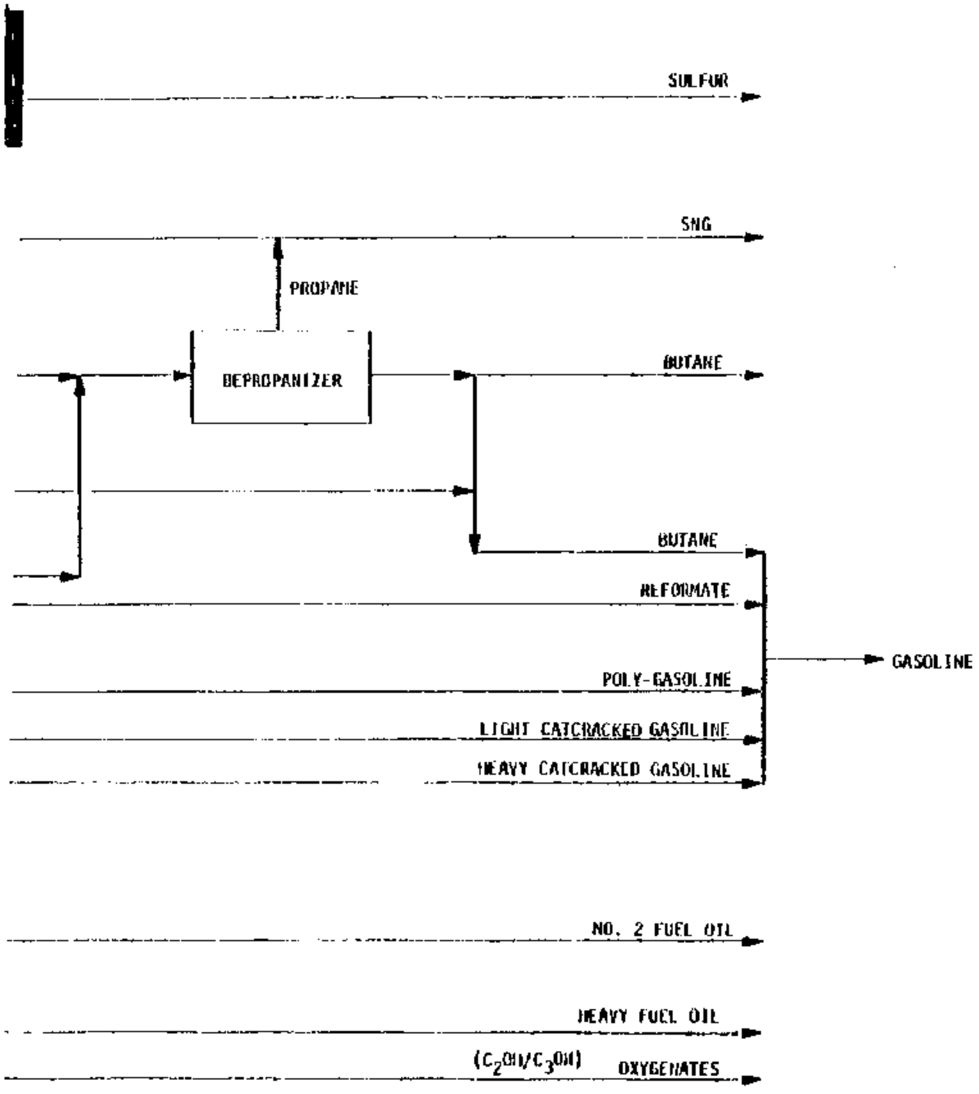
[a] Calculated


AIR
OXYGEN PLANT
O_2
SHIFT CONVERSION
COAL
COAL PREPARATION
COAL
PROCESS GASIFICATION
GAS CLEANING
SLAG SLURRY
SOUR ACID GAS
WATER RECLAMATION
RECOVERE WATER
STEAM
STEAM AND POWER GENERATION
(STARTUP OR
STEAM


STACK GAS
H_2S RICH GAS
SULFUR PLANT
CO_2 VENT
ACID GAS REMOVAL
SYNGAS
ID GAS
:COVERED WATER
:UP ONLY)
PLANT FUEL GAS
EAM
PLANT POWER
FISCHER-TROPSCH SYNTHESIS
PURGE GAS
LIQUID HYDROCARBONS
CONDENSATE
CHEMICAL RECOVERY
WATER
LIQUID PRODUCT RECOVERY
$C_2^=$ & LTR.
METHANATION
C_3/C_4'S
$C_2^=$ & LTR.
$C_3^=$/
H_2 RICH GAS
C_5-400°F
NAPHTHA HYDROTREATER
C_5-400°F
H_2 RICH GAS
400°F+
CATALYTIC CRACKING & GAS PLANT
H_2 RICH GAS
LIG
HEAVY CYCL
OXYGENATES



C_3/C_4'S
$C_2^=$ & LTR.
H_2 RICH GAS
C_5-400°F
H_2 RICH GAS
H_2 RICH GAS
CATALYTIC CRACKING & GAS PLANT
$C_3^=/C_4^=$
LIGHT CYCLE OIL
HEAVY CYCLE OIL
DEBUTANIZER
$C_3^=/C_4^=$
CATALYTIC REFORMER
C_4 & LTR.
C_5+ REFORMATE
DISTILLATE HYDROTREATER
CATALYTIC POLYMN.



	TONS/DAY	BPSD (MMSCFD)	MMBTU/D (HHV)
FEED COAL	36,340	-	910
SNG (972 BTU/SCF)	7,275	52,665* (325)	316
BUTANES	1,185	11,750	51
GASOLINE	4,645	37,535	197
OXYGENATES	640	3,760	13
NO. 2 FUEL OIL	410	2,725	16
HEAVY FUEL OIL (0.0 WT% SULFUR)	170	1,075	7
SULFUR	1,230	-	-
TOTAL	15,555	109,510	600

*BARRELS FOE

THERMAL EFFICIENCY: $\frac{600}{910} \times 100 = 66\%$

0 ISSUE FOR REPORT

COAL LIQUEFACTION PROCESS SURVEY
BLOCK FLOW DIAGRAM
FISCHER-TROPSCH (FSC) PROCESS

THE RALPH M PARSONS COMPANY
PASADENA, CALIFORNIA

JOB NO 5658-1

DWG NO R-04-FS-1

REV 0

5-35

SECTION 6

ENVIRONMENTAL

6.1 GENERAL

This section defines the environmental procedures and equipment included in the designs of the five high potential processes selected, and compares projected effluents with applicable and related environmental standards.

Two major environmental aspects were considered in detail: air emissions and water treatment and supply. These aspects are discussed at first independently for each process; they are then compared with each other and with applicable standards to determine the relative environmental acceptability of each high potential process. Other aspects, such as generation and disposal of solid wastes, biohazards of the intermediates and products, and environmental acceptability of the fuels produced are also briefly reviewed.

The same data base utilized for the "Description of the High Potential Processes" (Section 5) was used to develop quantitative projections for air emissions and water consumption and discharge. All processes were assumed to use an Illinois No. 6 coal (3.4% sulfur, 7.1% ash) as raw material.

6.2 AIR EMISSIONS

The major air pollution abatement effort is aimed at removing particulates and sulfur dioxide from the gases generated during the coal conversion process to make the fuels produced environmentally acceptable.

The air pollution abatement procedures followed for each process are outlined in block flow diagrams, which also show projections for the types and amounts of the streams vented to the air from specific units. Effluents from various units are often combined into a main plant stack; amounts and concentrations emitted to the air from specific stacks for each process are detailed in a series of tables. Applicable standards and compliance of the individual gaseous emissions are discussed in the following sections.

6.2.1 SRC II PLANT

The generation and control of air emissions for the SRC II Plant are outlined in Figure 6-1, which also shows the nature and amount of all streams vented to the air. The effluent gases are shown vented separately to the air to identify the contribution of specific process units. However, the gaseous effluents from the selective acid gas removal unit and the tail gas treatment unit are combined in a single stack before venting to the air.

The coal drying unit is the only major source of particulate emisssion. A cyclone followed by a baghouse remove the majority of the particulates from the vent stream.

Particulates present in the gas stream generated by the process gasifier are removed by a cyclone followed by a dust filter. The solids collected (char and ash) are returned to the gasifier. After shift conversion the acid gases (mainly hydrogen sulfide, hydrogen cyanide, carbon oxysulfide and carbon dioxide) present in the process gasifier stream are separated from the other main syngas components (hydrogen, carbon monoxide, and methane) in a selective acid gas removal unit. On regeneration of the solvent, carbon dioxide with traces of carbon monoxide and hydrogen sulfide is separated from the other acid gases and vented to the air; hydrogen sulfide and other contaminants are conveyed to the sulfur recovery plant.

Acid gases originating from the dissolver and consisiting mainly of hydrogen sulfide are removed by amine scrubbing in an acid gas removal unit. On regeneration of the amine, the hydrogen sulfide liberated is conveyed to the sulfur recovery plant.

The sulfur recovery plant receives the two hydrogen sulfide streams mentioned above, plus a similar stream from the sour water stripping unit, and converts approximately 95% of the sulfur present to elemental sulfur; other contaminants are thermally oxidized to inoffensive compounds. The remainder of the sulfur is converted in a tail gas treatment unit, where sulfur species are reduced to hydrogen sulfide, absorbed by an alkaline redox solution, and oxidized to elemental sulfur. The final effluent, containing carbon dioxide plus traces of carbon oxysulfide, hydrogen sulfide, and carbon monoxide, is vented to the air.

The lower-Btu gas stream produced by the fuel gasifier is freed of particulates by a cyclone followed by an electrostatic precipitator; the solids collected (ash and char) are returned to the gasifier. Practically all remaining traces are removed by wet contact in the sulfur removal unit downstream. The hydrogen sulfide present is absorbed and converted to elemental sulfur in this unit using a redox process analogous to the one employed in the tail gas treatment unit mentioned above. The cleaned fuel gas is utilized for steam generation and process heating; on combustion of the fuel gas, carbon dioxide, sulfur dioxide, and nitrogen oxides are emitted to the air.

Amounts and concentrations of the combined effluents emitted to the air are detailed in Table 6-1, while the sulfur balance for the plant is presented in Table 6-2. Compliance with applicable standards is discussed in Section 6.2.6.

6.2.2 H-COAL PLANT

The dissolver in the H-Coal Plant employs a catalytic process, while the SRC II employs a psuedo-catalytic technology. Other key units employed in the H-Coal and in the SRC II plants serve similar purposes. The generation and control of air emissions for the H-Coal Plant are outlined in Figure 6-2; amounts and concentrations of the combined effluents emitted to the air are detailed in Table 6-3, while the sulfur balance is presented in Table 6-4. The different dissolving process is reflected in differing ratios of individual pollutants when composed with the SRC II plant.

6.2.3 CSF PLANT

The generation and control of air emissions for the CSF Plant are outlined in Figure 6-3, while it also shows the nature and amount of all streams vented to the air. The effluent gases are shown vented separately to the air to identify the contribution of specific process units. However, the gaseous effluents from the acid gas removal unit and the tail gas treatment unit are combined in a single stack before venting to the air.

The coal preparation unit is the only major source of particulate emissions. A cyclone followed by a baghouse remove most of the particulates from the vent stream.

Particulates present in the gas stream generated by the process gasifier are removed by a cyclone followed by an electrostatic precipitator. The solids collected (ash and char) are returned to the gasifier. The gas stream is then split into two fractions. One fraction undergoes shift conversion, then is conveyed to an acid gas removal unit, where the acid gases present (mainly hydrogen sulfide, hydrogen cyanide, carbon oxysulfide, and carbon dioxide) are separated from the other main syngas components (hydrogen, carbon monoxide, and methane). On regeneration of the solvent, carbon dioxide with traces of carbon monoxide and hydrogen sulfide is separated from the other acid gases and vented to the air; hydrogen sulfide and other contaminants are conveyed to the sulfur plant.

The other fraction is conveyed to a sulfur removal unit where the hydrogen sulfide present is absorbed by an alkaline redox solution and oxidized to elemental sulfur. The cleaned lower-Btu gas produced is used as plant fuel, in process heaters and steam boilers; on combustion of the fuel gas, carbon dioxide, sulfur dioxide, and nitrogen oxides are emitted to the air.

Gases produced on extraction and low temperature carbonization are treated similarly in a hydrogen sulfide removal unit. The desulfurized gas is also used as plant fuel.

The sulfur plant receives the hydrogen sulfide stream from the acid gas removal unit and converts approximately 95% of the sulfur present to elemental sulfur; other contaminants are thermally oxidized to inoffensive compounds. The remainder of the sulfur is converted in a tail gas treatment unit, where sulfur species are reduced to hydrogen sulfide, absorbed by an alkaline redox solution, and oxidized to elemental sulfur. The final effluent, containing carbon dioxide plus traces of carbon oxysulfide, hydrogen sulfide, and carbon monoxide, is vented to the air.

Amounts and concentrations of the combined effluents emitted to the air are detailed in Table 6-5, while the sulfur balance of the plant is presented in Table 6-6. Compliance with applicable standards is discussed in Section 6.2.6.

6.2.4 FISCHER-TROPSCH PLANT

The generation and control of air emissions for the Fischer-Tropsch (F-T) Plant are outlined in Figure 6-4, which also shows the nature and amount of all streams vented to the air. The effluents are shown vented separately to the air to identify the contribution of specific process units. However, all gaseous effluents are combined in a single plant stack before venting to the air.

The coal drying unit is the only major source of particulate emissions. A baghouse removes most of the particulates from the vent stream.

In-plant energy requirements for process heaters and steam boilers are satisfied by steam produced by the F-T process. Therefore, no emissions from combustion of fuel gas are generated. There is only one gasifier, the process gasifier; the gas stream produced is freed of particulates by an abatement system consisting of a cyclone followed by a hot electrostatic precipitator; the solids collected (ash and char) are returned to the gasifier. Practically all of the remaining particulates are removed downstream by wet scrubbing during condensate removal and passage through cold electrostatic precipitators. The gas stream is then desulfurized by an acid gas removal unit; the hydrogen sulfide separated is conveyed to a sulfur recovery and then tail gas treatment plant; these units operate similarly to the units described above for the SRC II and CSF plants. The last traces of sulfur present in the cleaned gas are removed by a zinc oxide guard bed, to avoid deactivating the F-T catalyst. Passage through the F-T catalytic reactors converts the synthesis gas to sulfur and nitrogen free liquid hydrocarbons and alcohols. Some CO_2 is also produced, removed by a CO_2 removal unit and vented to the air together with minor amounts of hydrocarbons and carbon monoxide.

Amounts and concentrations of the combined effluents emitted to the air are detailed in Table 6-7, while the sulfur balance for the plant is presented in Table 6-8. Compliance with applicable standards is discussed in Section 6.2.5.

6.2.5 COMPLIANCE WITH APPLICABLE SOURCE EMISSION STANDARDS

Source emission standards for coal conversion plants have not been issued by the Federal Government. However, emission standards for Coal Thermal Dryers, present in some coal conversion processes have been issued, and source emission standards for Petroleum Refinery Sulfur Recovery Plants, of a type similar to the ones employed in coal conversion technology, have been proposed.

Of the states, only New Mexico has issued specific regulations covering coal gasification plants. These regulations can be considered for illustrative purposes only because New Mexico is not included in the three coal source areas, namely the Appalachian Region of the Eastern Coal Province, the Eastern Region of the Interior Coal Province, and the Powder River Region of the Rocky Mountain Coal Province, selected in Section 3 as typical coal sources for this study. Three states representative of these regions are West Virginia, Illinois, and Wyoming; these states have issued standards for petrochemical and chemical manufacturing processes, which are related to coal conversion technology.

Applicable Federal, Illinois, New Mexico, West Virginia, and Wyoming source emission standards are listed in Table 6-9. The projected air emissions of the five high potential coal liquefaction processes are listed in Table 6-10; concentrations have been calculated on a dry basis to conform with the requirements of the standards. Two of the processes, CSF and Fischer-Tropsch are projected to meet all emission standards. The two other processes are projected to exceed some of the standards. The SRC II Plant is projected to exceed the allowable hydrogen sulfide emissions limits and the H-Coal Plant is projected to exceed the allowable nitrogen oxide emissions limits. It is believed that application of additional control technology presently available could bring these two processes into compliance with applicable standards. For example, use of countercurrent two-stage solvent and gas flows in the acid gas removal unit could reduce hydrogen sulfide emissions for the SRC II plant, while combustion modification could decrease the nitrogen oxides generated by the H-Coal process boilers.

6.3 WATER TREATMENT AND SUPPLY

Water treatment and supply are major environmental concerns for the five high potential coal liquefaction processes considered. It is assumed that for all processes the water is supplied by a nearby river; this water is pumped and used for cooling water makeup and boiler feedwater makeup. The progressive treatment and disposition of the aqueous effluent streams is considered for each process; the procedures involved are outlined in block flow diagrams, which also show water flow rates for the major streams. Water consumption is discussed in a separate section.

6.3.1 SRC II PLANT

The generation and treatment of aqueous contaminants for the SRC II Plant is outlined in Figure 6-5. Wastewater sources are listed on the left hand side of the figure, with the degree of pollution of the wastewater streams decreasing from top to bottom. Treatment and disposition of the streams is also shown; approximate flow rates are reported. The water supply system is outlined on the right hand side. Raw river water is purified by flocculation and settling and used for cooling water makeup and, after further sand filtration and deionization, for boiler feedwater makeup.

The most highly contaminated stream is the sour water generated by several process units, such as the gasifiers, the dissolver, and the product distillation and hydrotreating units. This stream contains hydrogen sulfide, ammonium sulfide, phenols, cresols, thiocyanates, cyanides and solids (ash and char). Treatment consists of stream stripping to remove hydrogen sulfide and ammonia; the aqueous stream is then used as reagent water in the gasifiers, where organic contaminants undergo thermal destruction. Filters on return condensate streams remove the solids present.

Blowdown waters from the cooling tower and the boilers, containing small amounts of corrosion inhibitors (zinc salts and inorganic phosphates) are combined with soluble inorganic salts from the deionizer wastewater, neutralized, and treated with coagulants to precipitate suspended solids. The clean effluent water is then used for slag quench and dust control as required with the excess returned to the river.

6.3.2 H-COAL PLANT

The purification of raw river water supply and the generation and treatment of aqueous contaminants for the H-Coal Plant is outlined in Figure 6-6. Except for flow rates, the water supply and water treatment system is identical with the one discussed above for the SRC II Plant.

6.3.3 CSF PLANT

The purification of raw river water supply and the generation and treatment of aqueous contaminants for the CSF Plant is outlined in Figure 6-7. Except for flow rates, the water supply and water treatment system is identical with the one discussed above for the SRC II Plant.

6.3.4 FISCHER-TROPSCH PLANT

The generation and treatment of aqueous contaminants for the Fischer-Tropsch Plant is outlined in Figure 6-8. Wastewater sources are listed on the left hand side of the figure, with the degree of pollution of the wastewater streams decreasing from top to bottom. Treatment and disposition of the streams is also shown; approximate flow rates are reported. The water supply system is outlined on the right hand side. Raw river water is purified by flocculation and settling and used for cooling water makeup and, after further sand filtration and deionization, for boiler feedwater makeup.

The most highly contaminated stream is the sour water generated by several process units, such as the gasifiers, the product distillation and hydrotreating units. This stream contains hydrogen sulfide, ammonium sulfide, phenols, thiocyanates, trace quantity of cyanides and solids (ash and char). Treatment consists of steam stripping to remove hydrogen sulfide and ammonia; the aqueous stream then undergoes wet oxidation with conversion of the organic materials to carbon dioxide, nitric oxide, and sulfur dioxide. These gases are conveyed to the gasifier, where nitric oxide is reduced to nitrogen and ammonia and sulfur dioxide is reduced to hydrogen sulfide. The purified aqueous stream is deionized and used for boiler feedwater makeup.

A second aqueous effluent stream containing large amounts of organics (alcohols, aldehydes, and organic acids) is produced on condensation of the Fischer-Tropsch synthesis product stream. This stream undergoes chemical treatment with caustic, then is combined with boiler water blowdown, and concentrated in a triple effect evaporator. The evaporator condensate is used for boiler feedwater makeup, while the residue is sprayed on the feed coal to the gasifier.

Blowdown water from the cooling tower, containing small amounts of corrosion inhibitors (zinc salts and inorganic phosphates) is combined with soluble inorganic salts from the deionizer wastewater, neutralized, and treated with coagulants to precipitate suspended solids. The clean effluent water is then used for slag quench and dust control as required, with the excess returned to the river.

6.3.5 APPLICABLE AQUEOUS EFFLUENT STANDARDS

No aqueous effluent standards specifically addressed to coal-conversion plants have been issued by the Federal Government, or by state legislatures. Standards that are somewhat related to coal conversion processes are the Federal standards issued for petroleum refining. Maximum concentrations which were the base for Petroleum Refining New Source Performance Standards are reported in Table 6-11; discharges from the plants are expected to meet these standards. Actual information on the composition of the effluent streams is not available.

Many states have issued standards applicable to all sources discharging to the natural waters of the state. For illustration purposes, standards issued by the State of Illinois are reported in Table 6-12. Aqueous effluents from the plants would also have to meet these or similar state standards.

6.3.6 WATER CONSUMPTION

Water requirements for the four high potential processes considered are listed and compared graphically in Figure 6-9. The requirements are lowest for the SRC II, H-Coal and the Fischer-Tropsch processes and nearly 50% higher than their average for the CSF process. As shown in the figure, most of the water requirements are for cooling water, rather than for boiler and process water. A decrease in cooling water requirements could be obtained using wet-dry cooling towers in place of the wet cooling towers planned for the base case location.

6.4 SOLID WASTES

Large amounts of ash and slag (approximately 200 TPD for each plant) are expected to be generated. The available disposal procedures for these waste products are (1) return to the mine for burial with the mine spoils or (2) discard in a suitable land fill. Contact of these materials with aquifers should be avoided, due to the possibility of leaching of metals.

Wastewater treatment procedures produce treatment sludges which may be contaminated with metals (e.g. zinc used as corrosion inhibitor). These sludges could aslo be disposed of at a mine site or landfill, as long as the possibility of ground or surface water contamination by leaching, is excluded.

6.5 BIOHAZARDS

Of particular interest in coal conversion projects is the possible formation of carcinogenic compounds on hydrogenation and pyrolysis of coal. These compounds are polynuclear aromatic hydrocarbons and heterocyclics usually found in coal tar.

Under the operating conditions of the entrained slagging type coal gasifiers used in the four processes considered, nil coal oil and coal tars are expected to be produced. The entire dissolver trains in the SRC II and H-Coal plants, and the solvent extraction train in the CSF Plant, however, handle coal-derived oils, and will therefore require strict application of industrial hygiene practices.

No dissolvers or solvent extraction units are included in the design of the Fischer-Tropsch plant. For this process, therefore, no coal-derived carcinogenic hazards are expected.

6.6 ENVIRONMENTAL ACCEPTABILITY OF THE FUEL PRODUCTS

Under authority of the Clean Air Act, the Environmental Protection Agency has issued regulations concerning the registration of commercial fuels;[19] one of the requirements is testing for potential public health effects, including carcinogenic effects. This aspect has been discussed in the previous section:

The regulations also cover air emissions generated on combustion of fuels. The synthetic fuel oils produced by direct liquefaction (SRC II, H-Coal, and CSF processes) may contain 1 to 1.6% nitrogen; the amount of nitrogen oxides produced on combustion is therefore expected to be higher than for corresponding petroleum derived fuels (most common nitrogen content, 0.01 to 0.2%).

The same synthetic fuel oils also contain significant amounts of sulfur (up to the 0.5% value of SRC II fuel oil), which may prohibit their use in low air quality areas. For example, SRC II fuel oil and H-Coal residual fuel oil (0.3% sulfur) would not be acceptable in Southern California, where the maximum sulfur content allowed in fuel oil in 0.25%.

The fuels produced by indirect liquefaction (Fischer-Tropsch) on the other hand, contain nil sulfur and nitrogen.

Table 6-1 - Combined Effluents Emitted to the Air, SRC II Plant

Outlet	Gaseous Effluent	Amount	Concentration (ppm)
Main Stack	Carbon Dioxide	13,871 TPD	-
	Carbon Monoxide	6.2 TPD	565
	Carbon Oxysulfide (COS)	0.51 TPD	21.7
	Hydrogen Sulfide (H_2S)	321 lb/day	12.0
Process Heaters and Steam Boilers	Carbon Dioxide	14,480 TPD	-
	Sulfur dioxide	150 lb/day	0.6
	Nitrogen oxides (as NO_2)	5 TPD	62.6
Coal Preparation Plant	Particulates	0.8 TPD	-

Table 6-2 - Sulfur Balance, SRC II Process

Item	TPD
Total Input from the Typical Feed Coal	1,041.0
Outputs:	
Recovered as Elemental Sulfur	988.2
As Reduced Sulfur Emissions (36% H_2S, 64% COS)	0.4
As Sulfur Dioxide Emissions from Combustion of Fuel Gas	0.05
In the Liquid Fuel Products	52.4
Total	1,041.0

Table 6-3 - Combined Effluents Emitted to the Air, H-Coal Plant

Outlet	Gaseous Effluent	Amount	Concentration (ppm)
Main Stack	Carbon Dioxide	18310 TPD	-
	Carbon Monoxide	1.7 TPD	107
	Carbon Oxysulfide (COS)	0.61 TPD	17.8
	Hydrogen Sulfide (H_2S)	205.9 lb/day	5.5
Process Heaters and Steam Boilers	Carbon Dioxide	12,701 TPD	-
	Sulfur Dioxide	117 lb/day	0.6
	Nitrogen Oxides (as NO_2)	4.7 TPD	67
Coal Preparation Plant	Particulates	0.94 TPD	-

Table 6-4 - Sulfur Balance, H-Coal Process

Item	TPD
Total Input from the Typical Feed Coal	1,096.7
Outputs:	
Recovered as Elemental Sulfur	1,073.8
As Reduced Sulfur Emissions (23% H_2S, 77% COS)	0.4
As Sulfur Dioxide Emissions from Combustion of Fuel Gas	0.05
In the Liquid Fuel Products	22.5
Total	1,096.7

Table 6-5 - Combined Effluents Emitted to the Air, CSF Plant

Outlet	Gaseous Effluent	Amount	Concentration (ppm)
Main Stack	Carbon Dioxide	13753 TPD	-
	Carbon Monoxide	18.47 TPD	1774
	Carbon Oxysulfide (COS)	0.28 TPD	12.5
	Hydrogen Sulfide (H_2S)	204 lb/day	8.1
Process Heaters and Steam Boilers	Carbon Dioxide	16220 TPD	-
	Sulfur Dioxide	100 lb/day	0.6
	Nitrogen Oxides (as NO_2)	6 TPD	96
Coal Preparation Plant	Particulates	0.95 TPD	-

Table 6-6 - Sulfur Balance, CSF Process

Item	TPD
Total Input from the Typical Feed Coal	1,214.3
Outputs:	
Recovered as Elemental Sulfur	1,201.1
As Reduced Sulfur Emissions (39% H_2S, 61% COS)	0.2
As Sulfur Dioxide Emissions from Combustion of Fuel Gas	0.2
In the Liquid Fuel Products	13.0
Total	1,214.3

Table 6-7 - Combined Effluents Emitted to the Air, Fischer-Tropsch Plant

Outlet	Gaseous Effluent	Amount	Concentration (ppm)
Plant Stack	Carbon Dioxide	51,660 TPD	-
	Carbon Monoxide	11.81 TPD	520
	Carbon Oxysulfide (COS)	1.7 TPD	21.5
	Hydrogen Sulfide (H_2S)	316 lb/day	5.5
	C_2-C_6 Hydrocarbons (as CH_4)	1.55 TPD	65
Coal Preparation Plant	Particulates	0.97 TPD	-

Table 6-8 - Sulfur Balance, Fischer-Tropsch Process

Item	TPD
Total Input from the Typical Feed Coal	1,235.6
Outputs:	
Recovered as Elemental Sulfur	1,234.6
As Reduced Sulfur Emissions (14% H_2S, 86% COS)	1.0
Total	1,235.6

Table 6-9 - Federal, Illinois, New Mexico, West Virginia, and Wyoming Source Emission Standards

Pollutant	Federal Standards	Illinois Standards (Petrochemical Plant)	New Mexico Standards (Coal Gasification Plant)	West Virginia Standards	Wyoming Standards
Particulate Matter					
Volumetric Rate	0.031 gr/ft^3 a	-	0.01 gr/ft^3	0.07 gr/ft^3 a	-
Mass Rate (general)	-	E = 24.8 $(P^{0.16})^b$	-	-	E = 17.31 $(P^{0.16})^b$
Mass Rate (SRC II)		77.9 lb/hr			54.4 lb/hr
Mass Rate (H-Coal)		78.5 lb/hr			54.8 lb/hr
Mass Rate (CSF)		79.8 lb/hr			55.7 lb/hr
Mass Rate (Fischer-Tropsch)		80.0 lb/hr			55.9 lb/hr
Carbon Monoxide	-	200 ppm, 50% excess air	-	-	-
Organics (methane excluded)	-	100 ppm (CH_4 equivalent)	-	-	-
Sulfur Dioxide	250 ppm c	1.2 lb/MM Btu	-	2000 ppm	2000 ppm
Nitrogen Oxides	-	0.7 lb/MM Btu	-	-	-
Hydrogen Sulfide					
Emissions	10 ppm c	-	10 ppm	-	-
Fuel Content	0.10 gr/ft^3 c	-	-	0.50 gr/ft^3	-
Total Reduced Sulfur (H_2S + COS + CS_2)	300 ppm c	-	100 ppm	-	-
Hydrogen Cyanide	-	-	10 ppm	-	-
Hydrogen Chloride/ Hydrochloric Acid	-	-	5 ppm	145 ppm	-
Ammonia	-	-	25 ppm	-	-
Gas Burning Process Boilers, Particulate Matter	-	-	0.03 lb/MM Btu, LHV	-	-
Gas Burning Process Boilers, Sulfur Dioxide	-	0.03 lb/MM Btu, HHV	0.16 lb/MM Btu, LHV	-	-
Gas Burning Process Boilers, Nitrogen Oxides	0.2 lb/MM Btu	0.2 lb/MM Btu	-	-	0.2 lb/MM Btu
Coal Burning Process Boilers, Particulate Matter	-	0.10 lb/MM Btu	-	-	0.10 lb/MM Btu
Coal Burning Process Boilers, Sulfur Dioxide	-	1.2 lb/MM Btu	-	1.6 lb/MM Btu	0.2 lb/MM Btu
Coal Burning Process Boilers, Nitrogen Oxides	0.7 lb/MM Btu	0.7 lb/MM Btu	-	-	0.7 lb/MM Btu
Total Sulfur	-	-	0.008 lb/MM Btu of feed	-	-

[a] Standard for coal thermal dryers
[b] E = emission rate, lb/hr; P = process input weight (ton/hour)
[c] Proposed standard, petroleum refinery sulfur recovery plant (41 FR 43866, Oct. 4, 1976).
[d] See particulate mass rate above

Table 6-10 - Air Emissions, Coal Liquefaction Plants

Pollutant	SRC II	H-Coal	CSF	Fischer-Tropsch
Particulate matter:				
Volumetric Rate	0.03 gr/ft^3	0.03 gr/ft^3	0.03 gr/ft^3	0.03 gr/ft^3
Mass Rate	66.7 lb/hr	78.3 lb/hr	79.2 lb/hr	80.8 lb/hr
Carbon Monoxide	565 ppm[a]	107 ppm[a]	1774 ppm[a]	320 ppm[a]
Organics (methane excluded)	nil	nil	nil	63.1 ppm[b]
Sulfur Dioxide	nil	nil	nil	nil
Nitrogen Oxide	nil	nil	nil	nil
Hydrogen Sulfide:				
Emissions	12.0 ppm	5.3 ppm	8.1 ppm	3.5 ppm
Fuel Content	0.0004 gr/ft^3	0.0004 gr/ft^3	0.0004 gr/ft^3	nil
Total Reduced Sulfur (H_2S + COS + CS_2)	33.7 ppm	23.1 ppm	23.1 ppm	20.1 ppm
Hydrogen Cyanide	nil	nil	nil	nil
Hydrogen Chloride/ Hydrochloric Acid	nil	nil	nil	nil
Ammonia	nil	nil	nil	nil
Gas Burning Process Boilers, Particulate Matter	nil	nil	nil	c
Gas Burning Process Boilers, Sulfur Dioxide, HHV	0.002 lb/MM Btu	0.005 lb/MM Btu	0.001 lb/MM Btu	c
Gas Burning Process Boilers, Sulfur Dioxide, LHV	0.002 lb/MM Btu	0.005 lb/MM Btu	0.001 lb/MM Btu	c
Gas Burning Process Boilers, Nitrogen Oxides	1.12 lb/MM Btu	0.40 lb/MM Btu	0.11 lb/MM Btu	c
Coal Burning Process Boilers, Particulate Matter	c	c	c	c
Coal Burning Process Boilers, Sulfur Dioxide	c	c	c	c
Coal Burning Process Boilers, Nitrogen Oxides	c	c	c	c
Total Sulfur	0.001 lb/MM Btu	0.001 lb/MM Btu	0.001 lb/MM Btu	0.002 lb/MM Btu

[a] If the 50 excess air correction mentioned in the standard is applied, these values become: SRC II, 80 ppm, H-Coal, 20 ppm, CSF, 205 ppm Fischer-Tropsch, 126 ppm.

[b] Methane equivalent

[c] Not applicable because not included in process design.

[d] Underlined values exceed source emission standards.

Table 6-11 - New Source Performance Standards for the Petroleum Refining Industry[a]

Parameter	Maximum Concentration[b] (mg/ℓ)
BOD-5	10
COD	60
Total Organic Carbon	21
Suspended Solids	6
Oil and Grease	3
Ammonia-N	10
Phenol	0.06
Sulfide	0.06
Chromium, Tertiary	0.16
Chromium, Hexavalent	0.003

[a] Based on application of Best Available Demonstrated Technology (BADT).

[b] Converted from the mass standards reported in: "Development Document for Effluent Guidelines and New Source Performance Standards for the Petroleum Refining Point Source Category." United States Environmental Protection Agency, Report EPA-440/1-74-014a, Washington, D.C., April 1974 (p. 145, 147, 176), Petrochemical Subcategory.

Table 6-12 - Aqueous Effluent Standards, State of Illinois

Constituent	Maximum Concentration (mg/ℓ)
Arsenic (total)	0.25
Barium (total)	2.0
BOD 5	10.0
Cadmium (total)	0.15
Chromium (total hexavalent)	0.3
Chromium (total trivalent)	1.0
Copper (total)	1.0
Cyanide	0.025
Fluoride (total)	15.0
Iron (total)	2.0
Iron (dissolved)	0.5
Lead (total)	0.1
Manganese (total)	1.0
Mercury (total)	0.0005
Nickel (total)	1.0
Oil (hexane solubles or equivalent)	15.0
pH	range 5-10
Phenols	0.3
Selenium (total)	1.0
Silver	0.1
Zinc (total)	1.0
Total Suspended Solids	12.0

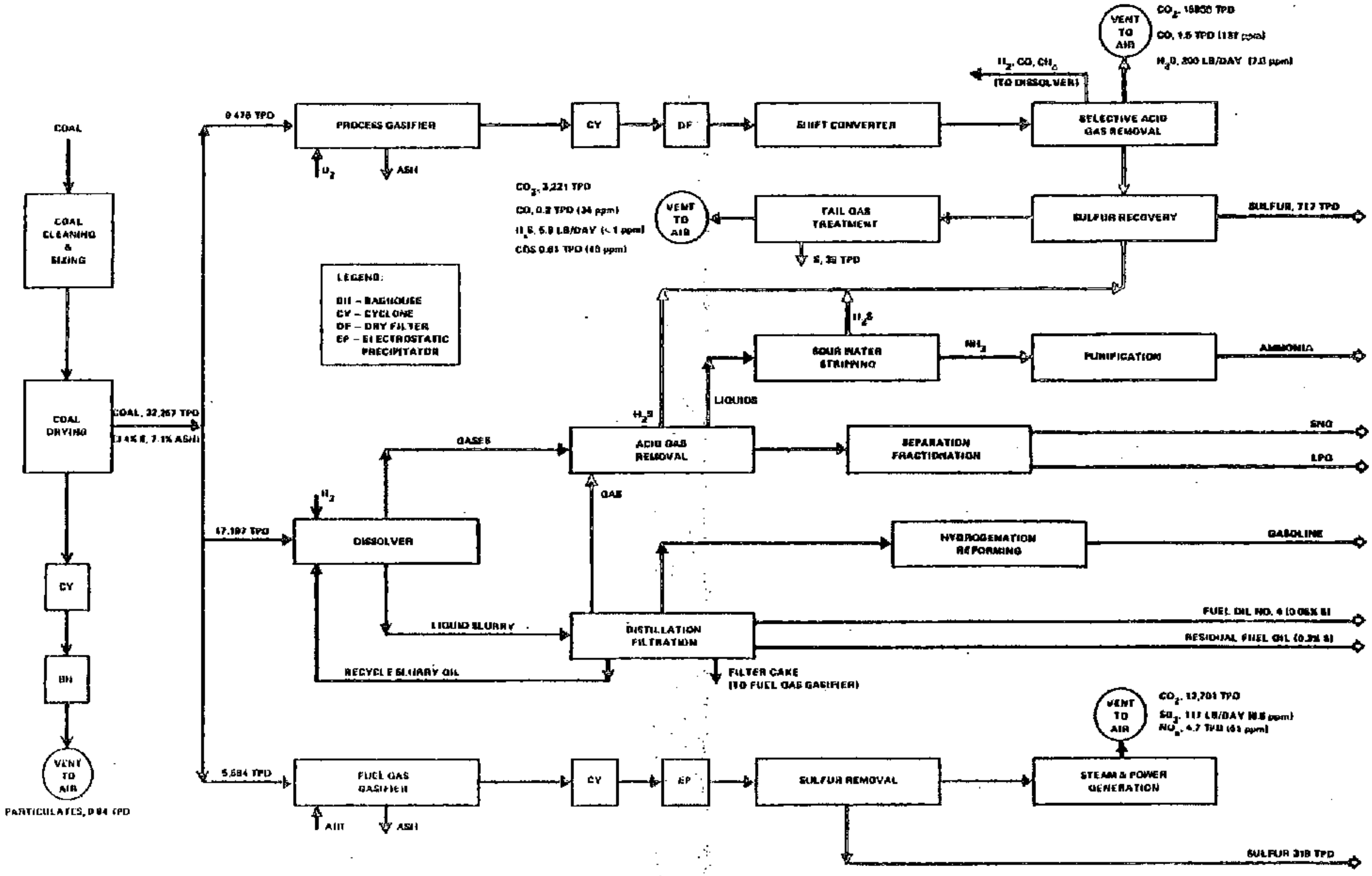


Figure 6-1 - Block Flow Diagram
Air Pollution Abatement, SRC II Plant

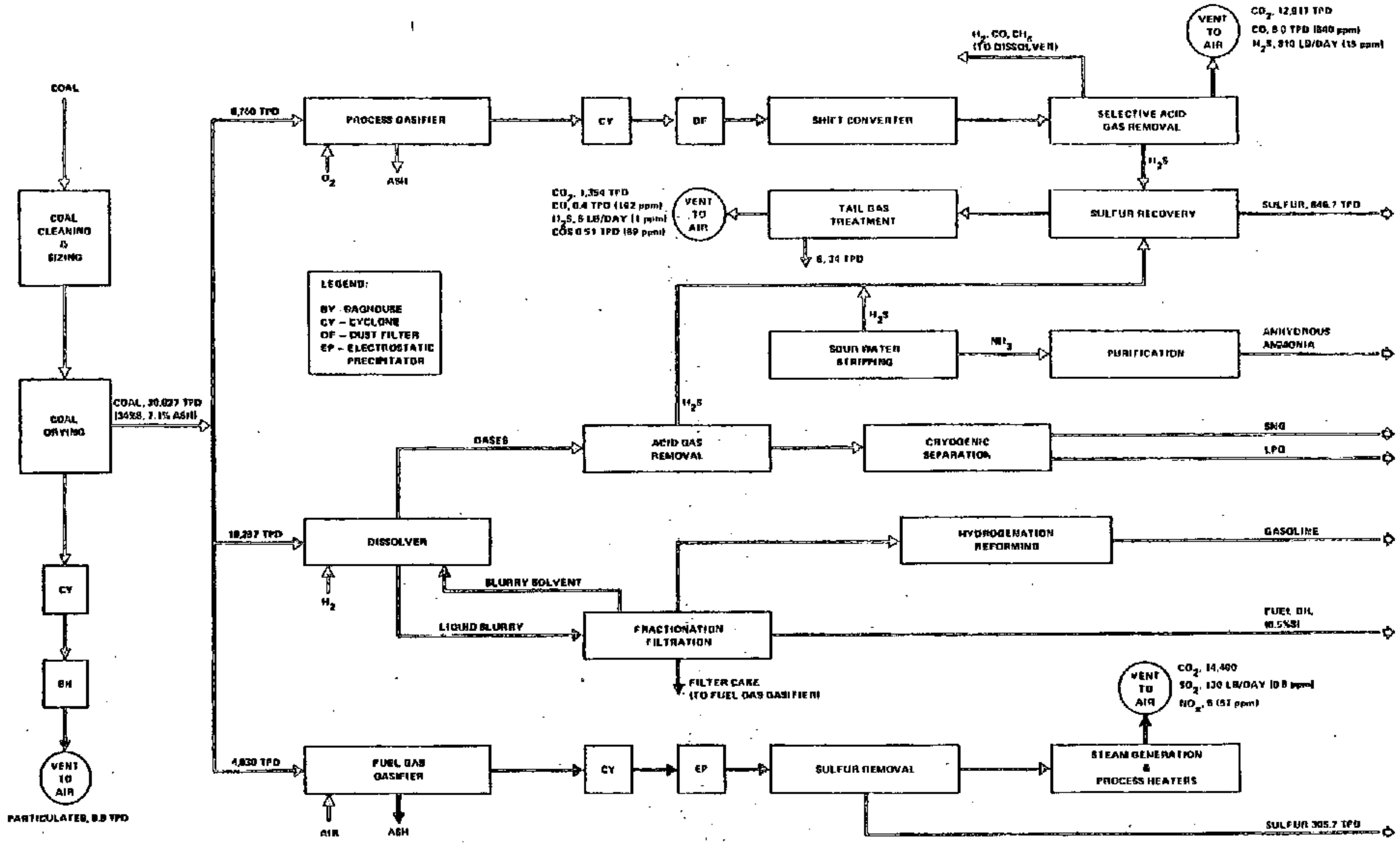


Figure 6-2 - Block Flow Diagram,
Air Pollution Abatement, H-Coal Plant

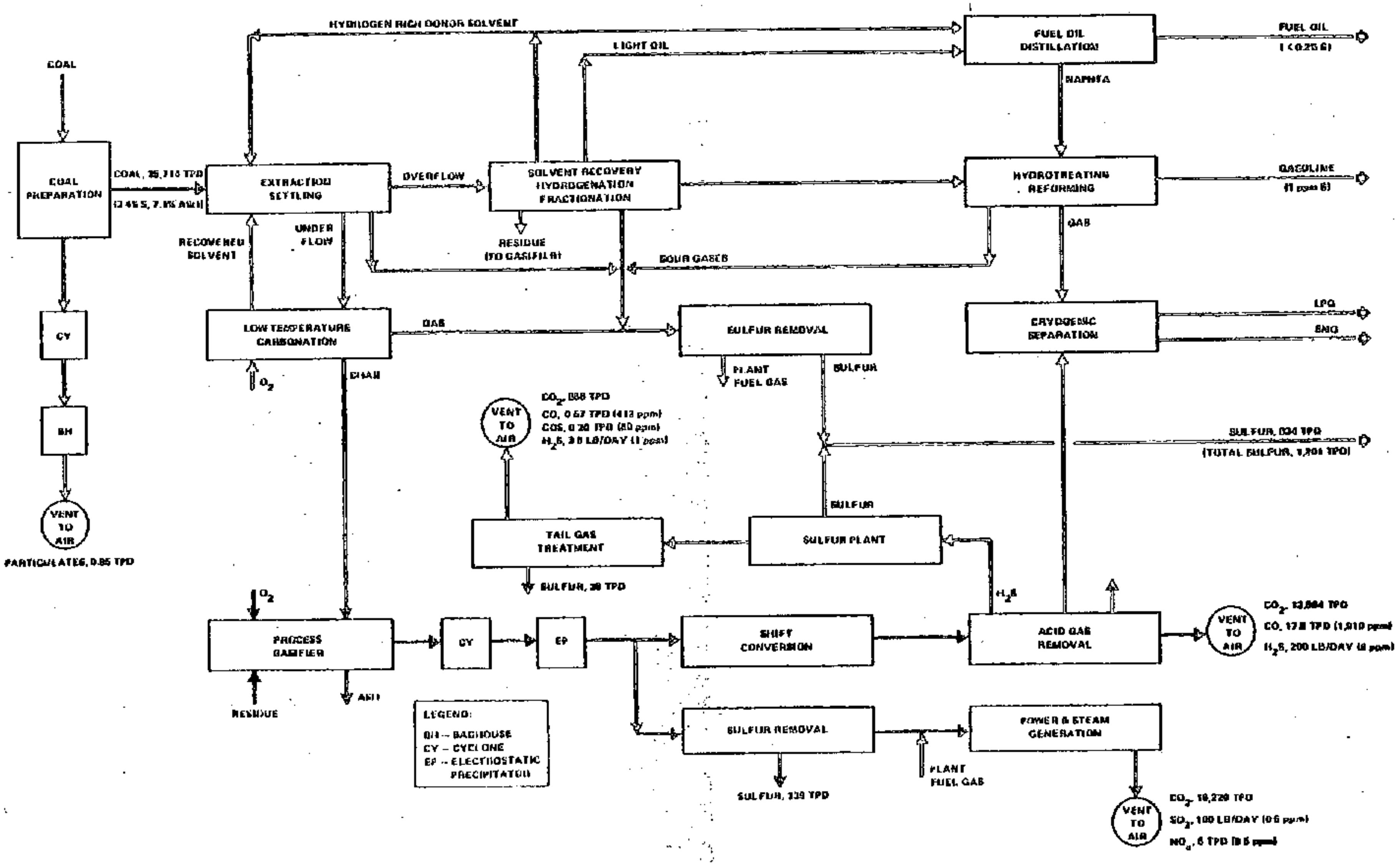


Figure 6-3 - Block Flow Diagram, Air Pollution Abatement, CSF Plant

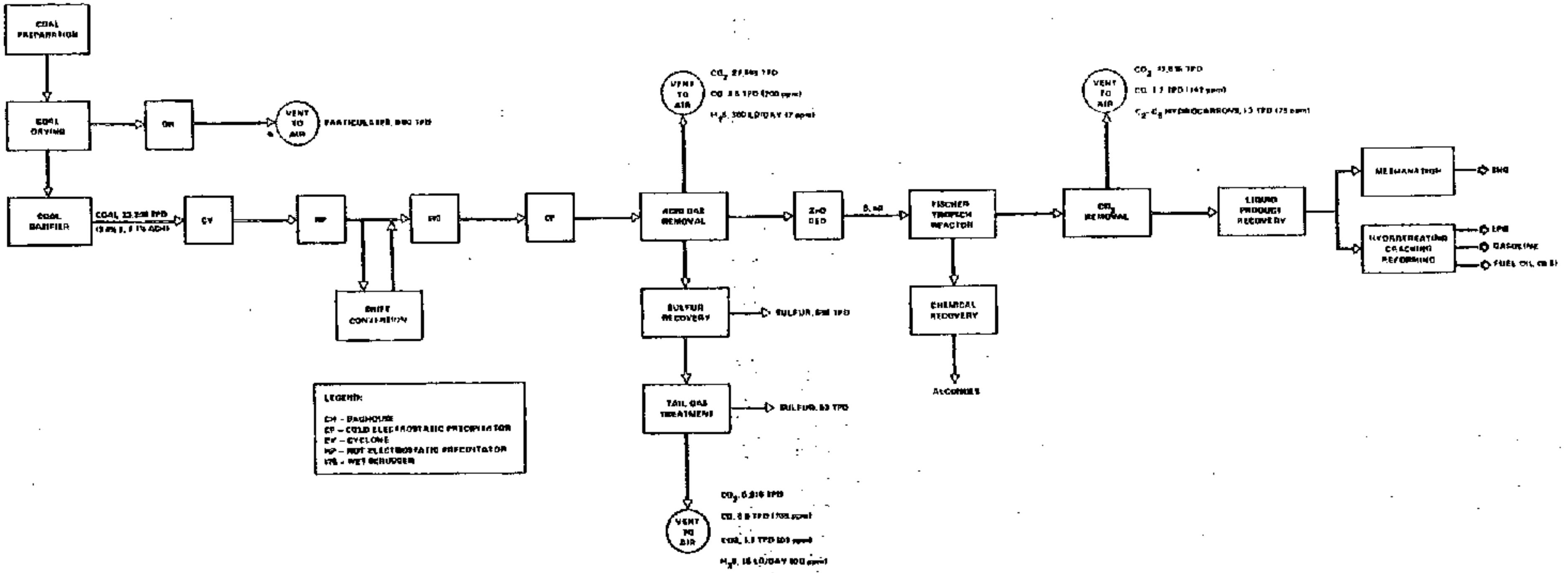


Figure 6-4 - Block Flow Diagram,
Air Pollution Abatement, Fischer-Tropsch Plant

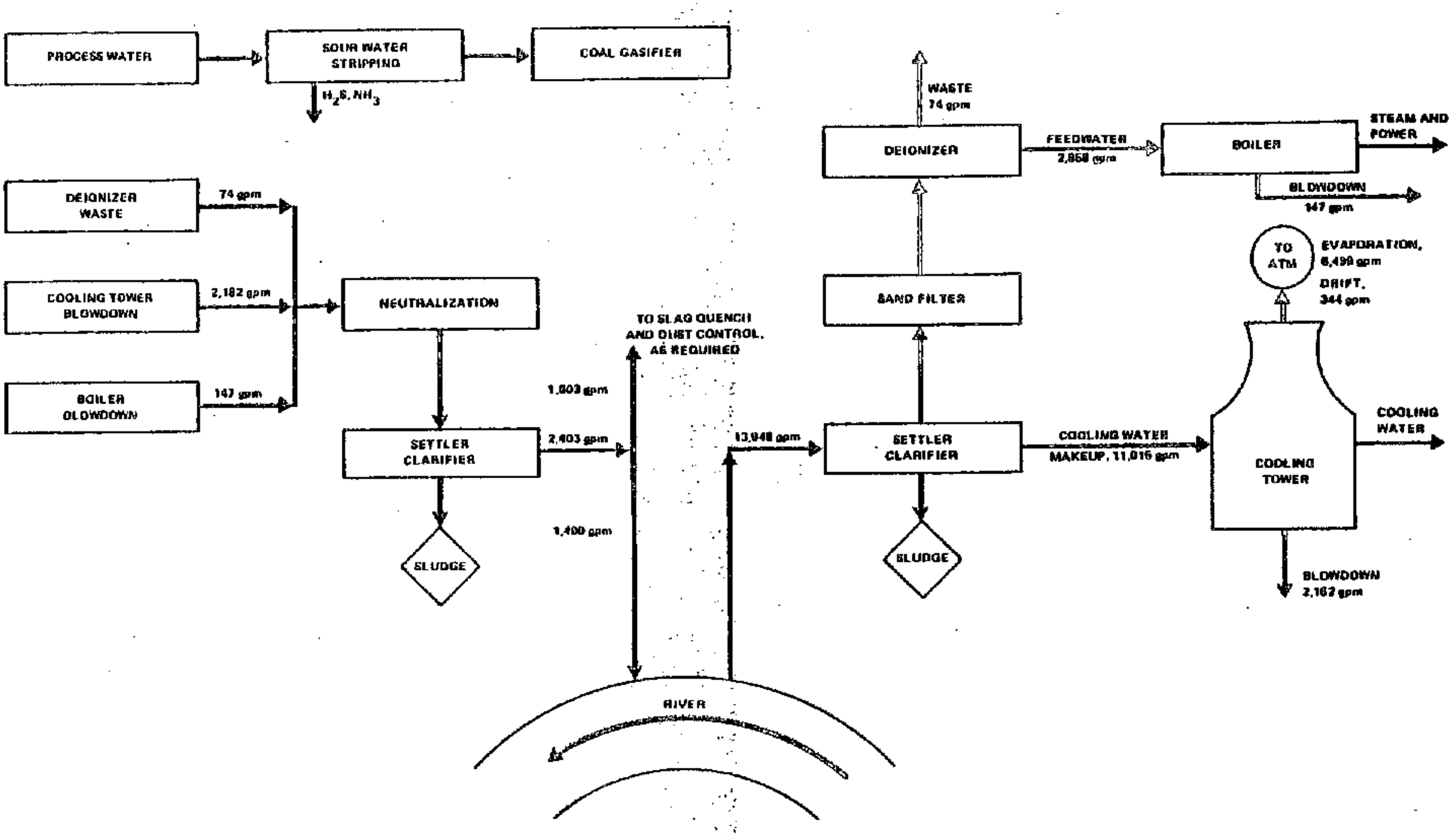


Figure 6-5 - Block Flow Diagram,
Water Treatment and Supply, SRC II Plant

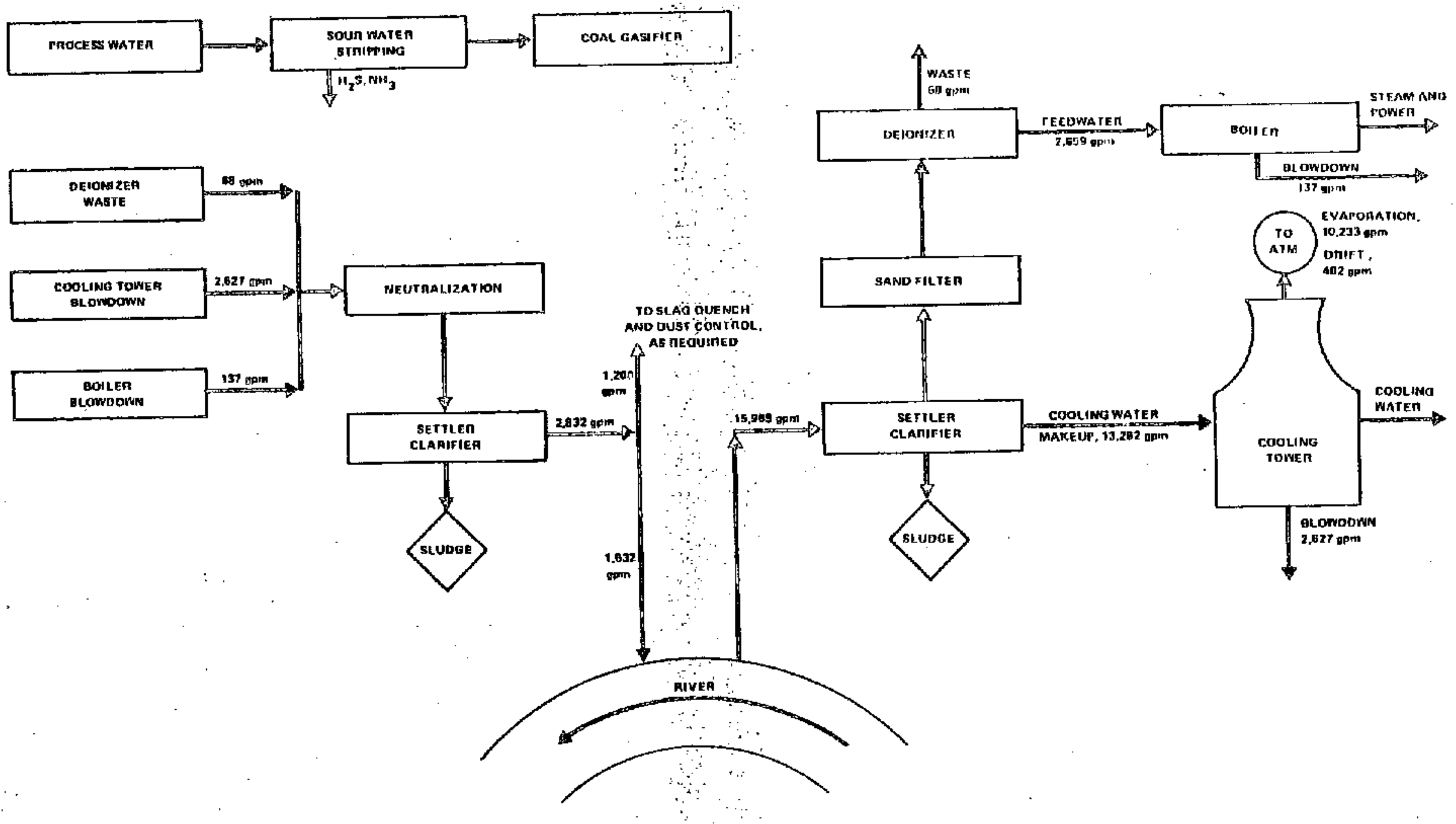


Figure 6-6 - Block Flow Diagram,
Water Treatment and Supply, H-Coal Plant

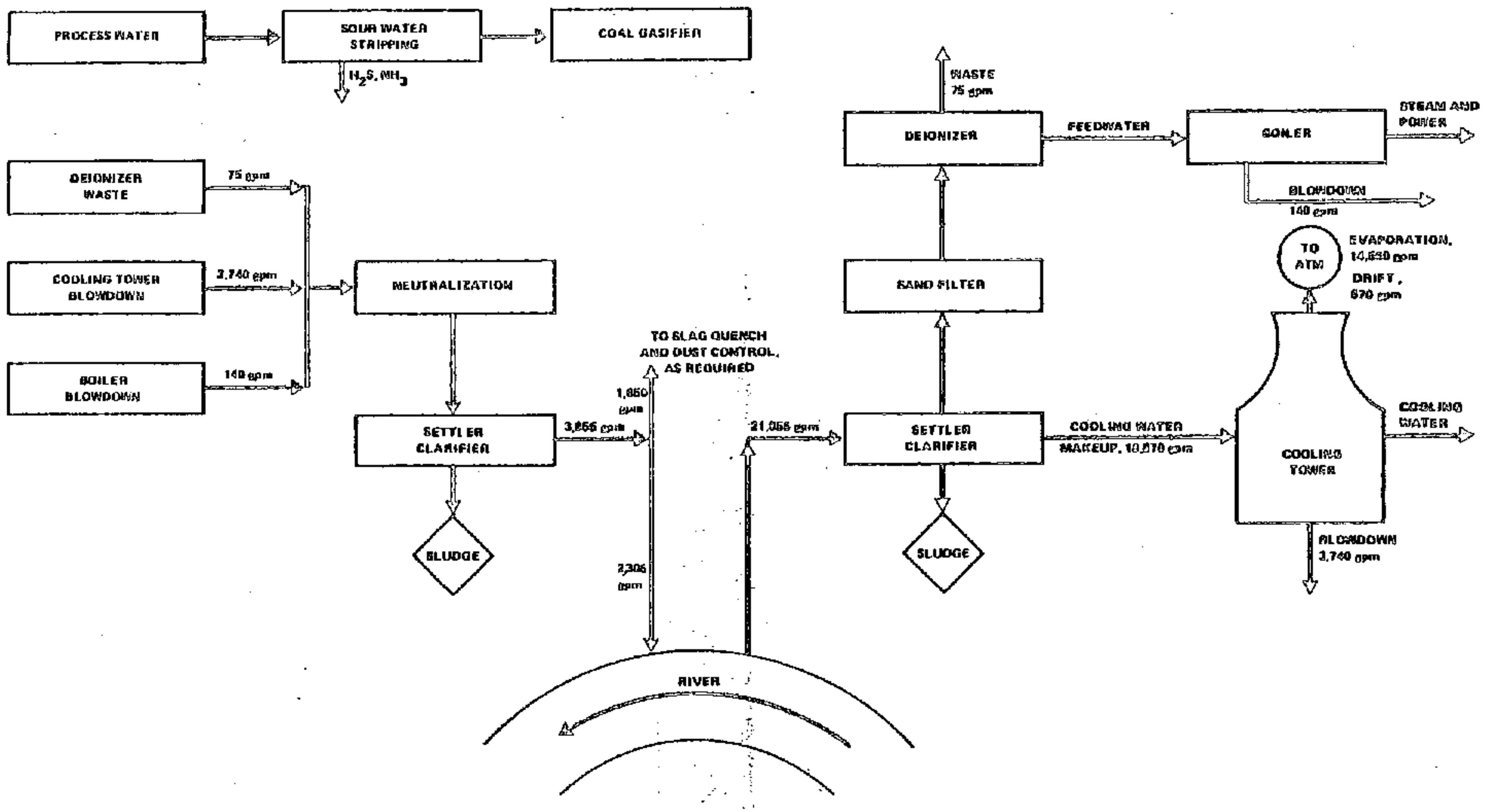


Figure 6-7 - Block Flow Diagram,
Water Treatment and Supply, CSF Plant

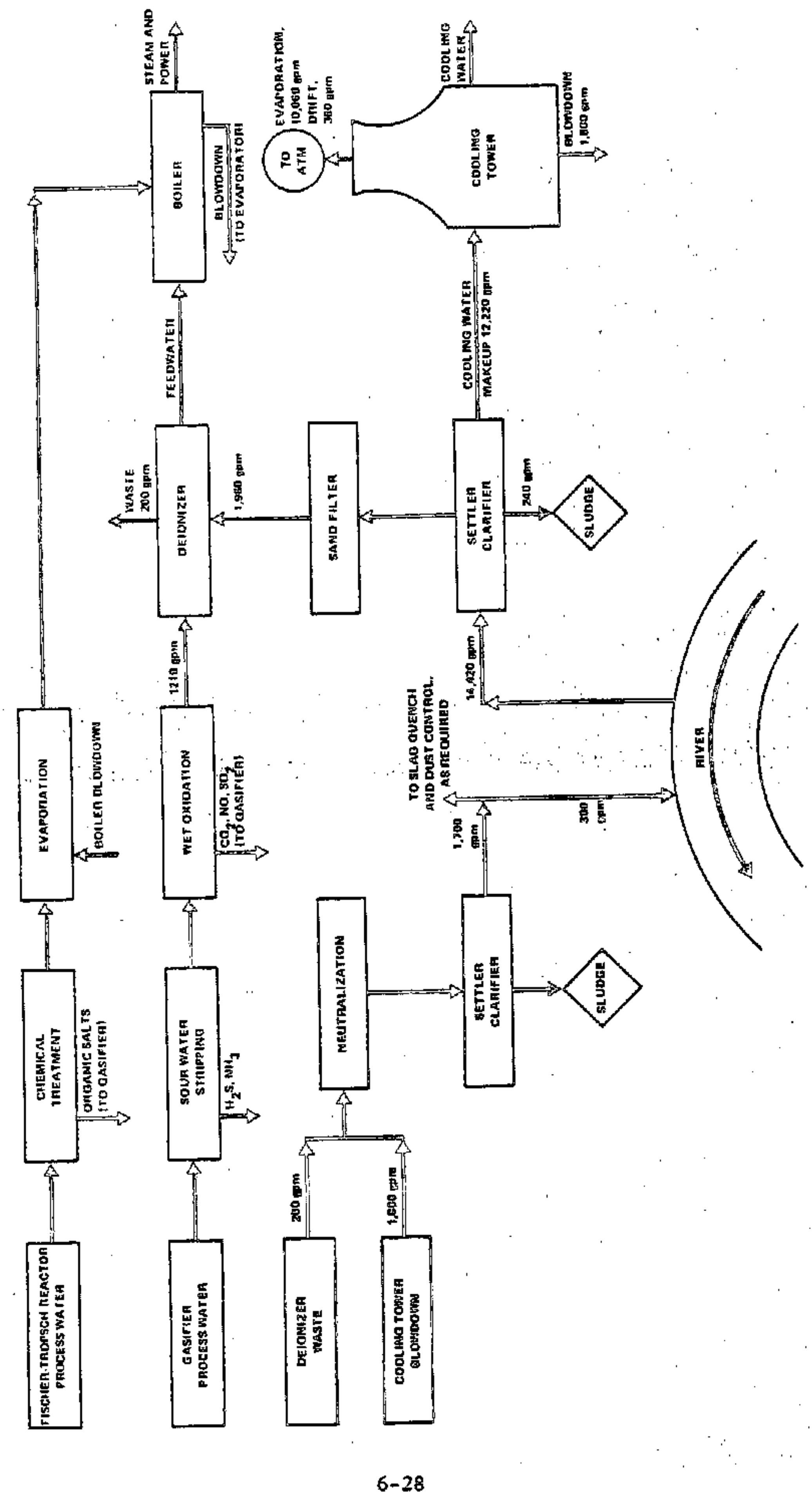
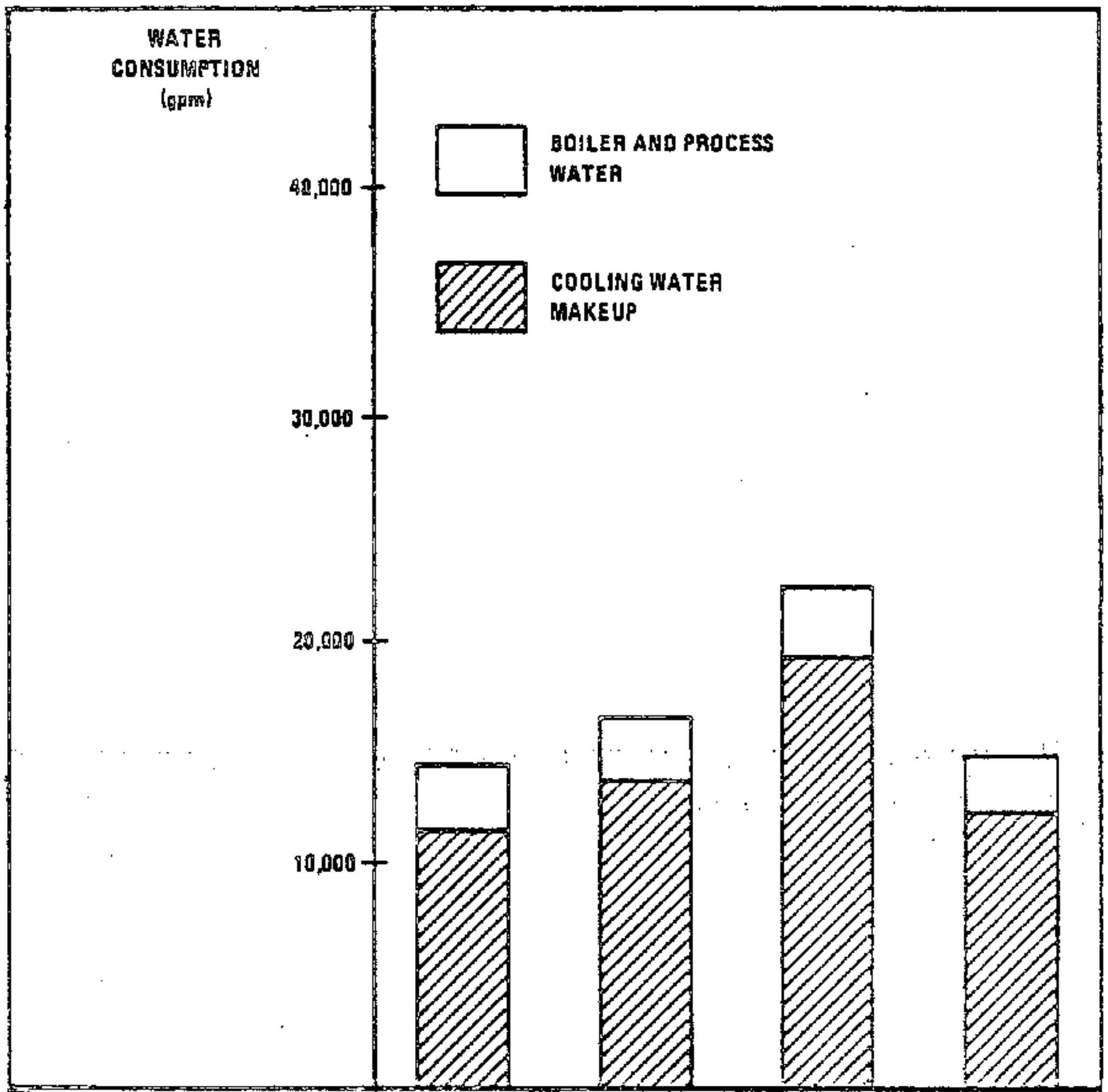


Figure 6-8 - Block Flow Diagram, Water Treatment and Supply, Fischer-Tropsch Plant



PROCESS / WATER USE (gpm)	SRC-II	H-COAL	C S F	FISCHER-TROPSCH
BOILER & PROCESS WATER	2,933	2,727	2,985	2,200
COOLING WATER MAKEUP	11,015	13,262	18,870	12,220
TOTAL WATER	13,948	15,989	21,855	14,420

Figure 6-9 - Comparison of Water Requirements for the Various Processes