3. INDIRECT LIQUEFACTION WITH KOPPERS-TOTZEK GASIFICATION AND FISCHER-TROPSCH TECHNOLOGIES

This section addresses indirect liquefaction facilities for the production of synthetic fuels by means of Koppers-Totzek (K-T) coal gasification followed by Fischer-Tropsch (F-T) product synthesis. Facilities of this type utilize all of the process operations normally associated with indirect liquefaction, namely coal preparation; coal gasification and raw gas cleaning; shift conversion and acid gas removal; and synthesis of the desired fuel product. Auxiliary processes required to support these production operations are those required for oxygen production, raw water treatment and process cooling. Depending upon the local availability and cost of electric power, on-site auxiliary power generation facilities may also be required.

Both the K-T and F-T processes are commercially proven and are currently in use abroad. The K-T process, as developed and licensed by Krupp-Koppers, GmbH, Essen, West Germany (Gesellschaft fur Kohle-Technologie (GKT) in the U.S.), is a commercially viable process which has been widely used outside the U.S. to produce industrial fuel gas and synthesis gas from coal. To date, the GKT K-T process has been used with a variety of coal feeds, ranging from brown coals through lignite and bituminous ranks and encompassing the full breadth of coking tendencies. The F-T synthesis process has been commercially applied for the production of liquids from coal-derived synthesis gases; the largest commercial application of F-T technology is SASOL facility in South Africa.

A wide variety of domestic coals are potential feedstocks for K-T based synthetic fuels facilities. In general, specific characteristics of the coal feedstocks will determine the characteristics of process and waste streams. To date, the North Alabama Coal Gasification Consortium has performed large scale K-T gasification tests only with an Illinois No. 6 coal (1). Thus, an Illinois No. 6 coal was chosen for examination to provide a basis for sizing and characterizing base plant process and waste streams and evaluating waste stream control options. Characteristics of the base plant Illinois No. 3 coal are summarized in Table 3-1.

TABLE 3-1. CHARACTERISTICS OF ILLINOIS NO. 6 COAL SELECTED FOP USE IN
INDIRECT LIQUEFACTION BASE PLANT (2,3)

	As Revised Basis (wt %)	Dry Basis (wt %)
Moisture	10.23	
Volatile Matter	34.70	
Fixed Carbon	46.0	
Ash	9.15	10.19
C	64.16	71.47
H	4.34	4.83
O	8.1	9.02
S	2.81	3.13
N	1.2	1.35
Heating Value MJ/kg	26.63	29.67

Major and Minor Elements in Coal
(%, on moisture-free whole coal basis)

Al	1.20	Mg	0.04
Ca	0.92	Na	0.060
Cl	0.28	Si	2.45
Fe	1.50	Ti	0.06
K	0.16		

Trace Elements
(ppm, on moisture-free whole coal basis)

As	1.0	Hg	1.1
B	132	Mo	7
Be	1.6	Mn	20
Br	17	Ni	14
Cd	<0.4	P	29
Co	4	Pb	10
Ce	20	Sb	0.1
Cu	12	Se	1.3
F	79	V	20
Ga	4.5	Zn	43
Ge	6.0		

In developing the base plant material flow estimates, a fixed coal feed rate of 27,216 Mg per day (as received basis) to gasification was used. In addition to the gasifier coal requirements, some K-T based synfuels facilities may include on-site coal-fired auxiliary boilers for power generation. Coal requirements for any such boilers will depend upon the amount of purchased electricity from off-site sources. Boiler fuel requirements could also be offset by using high energy process offgases as fuel. For K-T based F-T facilities which are self-sufficient in energy, auxiliary boiler energy requirements for electric power are assumed to be approximately 26% of the coal energy input to the gasifier (based upon an assumed process thermal efficiency of 40%). It should be noted that most plants are potentially self-sufficient with respect to steam and, depending upon the cost of electric power, an on-site power boiler may not be needed at all.

A typical upgraded product slate for the K-T based F-T plant examined in this study is summarized in Table 3-2. The principal products are gasoline and SNG with lesser amounts of oils, alcohols and LPG.

TABLE 3-2. ESTIMATED PRODUCT/BY-PRODUCT SLATE FOR K-T BASED F-T SYNFUELS PLANT*

Products/ By-Products	Mg/day	TJ/day
Gasoline	3630	172
Diesel Oil	735	34.6
Fuel Oil	215	9.91
LPG	273	13.6
SNG	2920	127
Alcohols	625	19.7
Total	8398	376.8

*Coal feed rate to gasification is 27216 Mg per day (as received basis).

3.1 BASE PLANT DESCRIPTION

Base plant process operations consist of coal preparation, coal gasification, gas purification and upgrading, crude product synthesis and separation, and product upgrading. In addition, the auxiliary processes required to

support a fully integrated, self-sufficient, liquid fuels production facility would include raw water treatment, power generation, and oxygen production. Pollution control processes applicable to the base plant are described & discussed subsequently in Section 3.2. Processes comprising the base plant and their associated waste streams are described briefly in this section. Simplified process flow diagrams are presented in Figures 3-1, 3-2, 3-3, and 3-4.

3.1.1 Coal Preparation

The coal preparation operation in a K-T based synfi   acility will be similar to those found in other coal-based plants such as pulverized coal-fired power plants. Equipment is provided to receive, transport, and store coal, and to prepare pulverized coal for gasification and consumption in onsite power boilers. Coal is received by conveyor, train, barge, or truck and is stored in either an active or inactive (emergency) storage pile, as necessary. Coal from storage is prepared for gasification/combustion by screening, crushing, drying, and pulverizing to a size predominantly less than 0.1 mm. Prepared coal moisture contents of 1 to 2% are required for gasification of bituminous coals (4,5). Dried and sized coal is stored in silos and transported to gasifiers and boilers as required.

Major waste streams associated with the coal preparation operation are storage pile runoff (Stream 201); fugitive dust emissions from coal storage and transport (Stream 200); dust from coal screening, crushing, and pulverizing (Streams 202 through 205); and coal dryer offgases (Stream 206). Storage runoff tends to contain high levels of suspended and dissolved solids and can be quite acidic in the case of Midwestern and Eastern coals. Dust from coal preparation consists of natural soil and overburden material as well as coal. Coal dryer offgases contain SO_x, NO_x, CO, and particulate matter (coal dust).

3.1.2 K-T Coal Gasification

The K-T process involves low pressure (slightly above atmospheric), entrained-flow slagging coal gasification in the presence of steam and oxygen. Flame temperatures may range from 2000-2300K during gasification with reactor temperatures of 1510-1860K (4,6,7,8). The gasifier is a water-cooled steel vessel with a refractory lining, which, in the most common two-headed configuration, resembles an ellipsoid with horizontally opposing burners at the apices. The newest installations (three gasifiers each at Ramagundam and
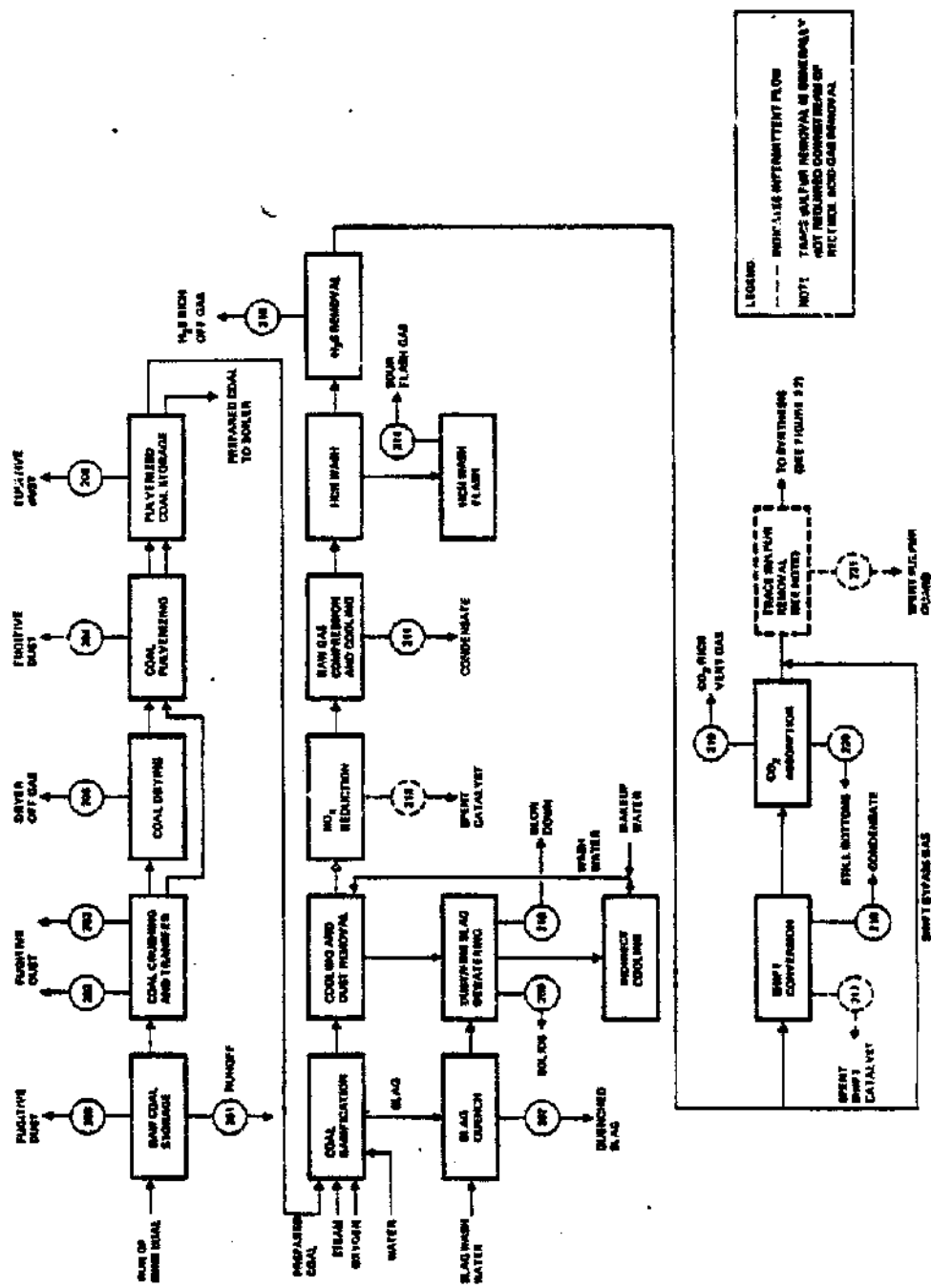
3-4

Figure 3-1. Operations associated with synthesis gas production in K-T based indirect liquefaction facilities
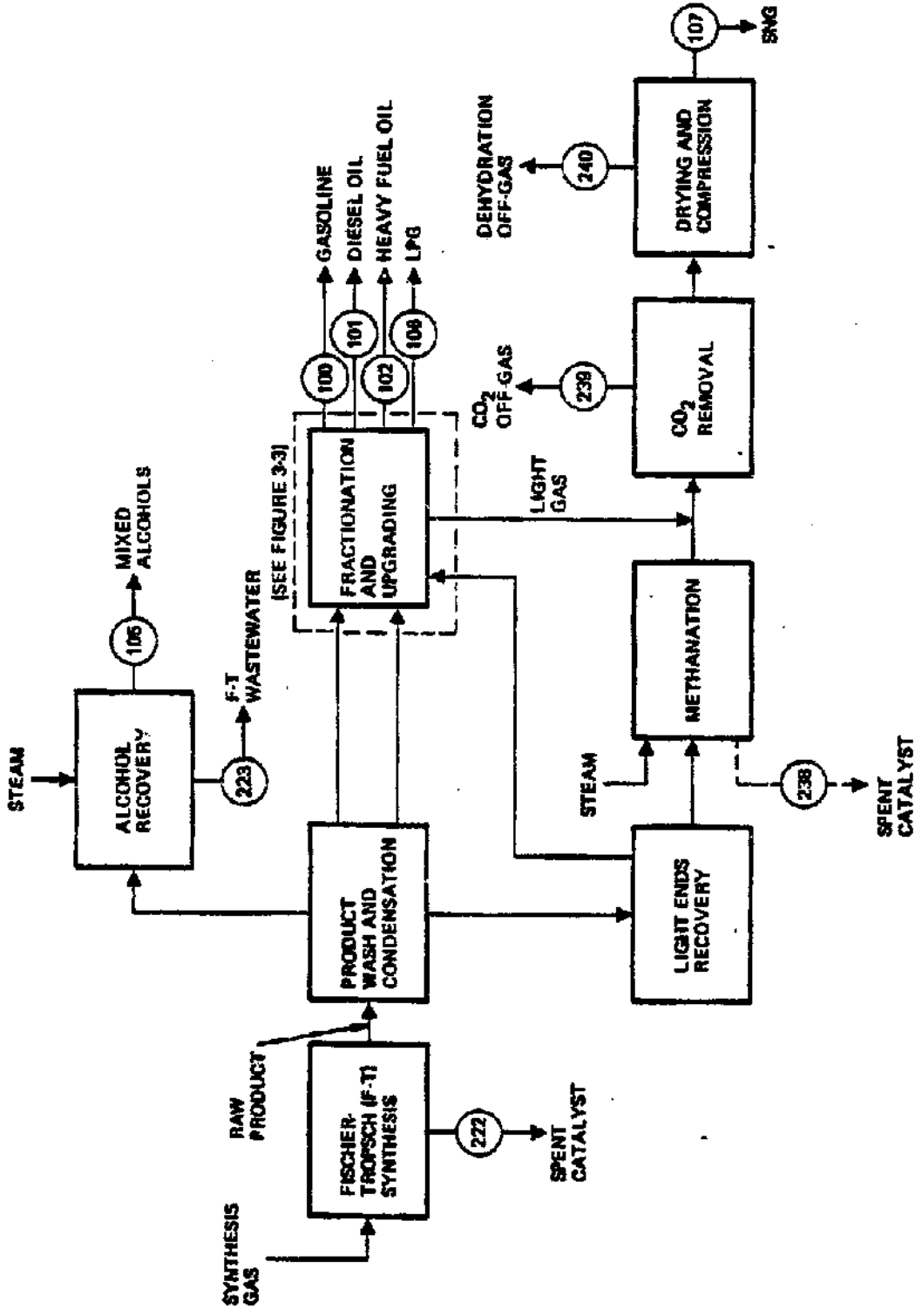
Figure 3-2. Fischer-Tropsch synthesis and product upgrading
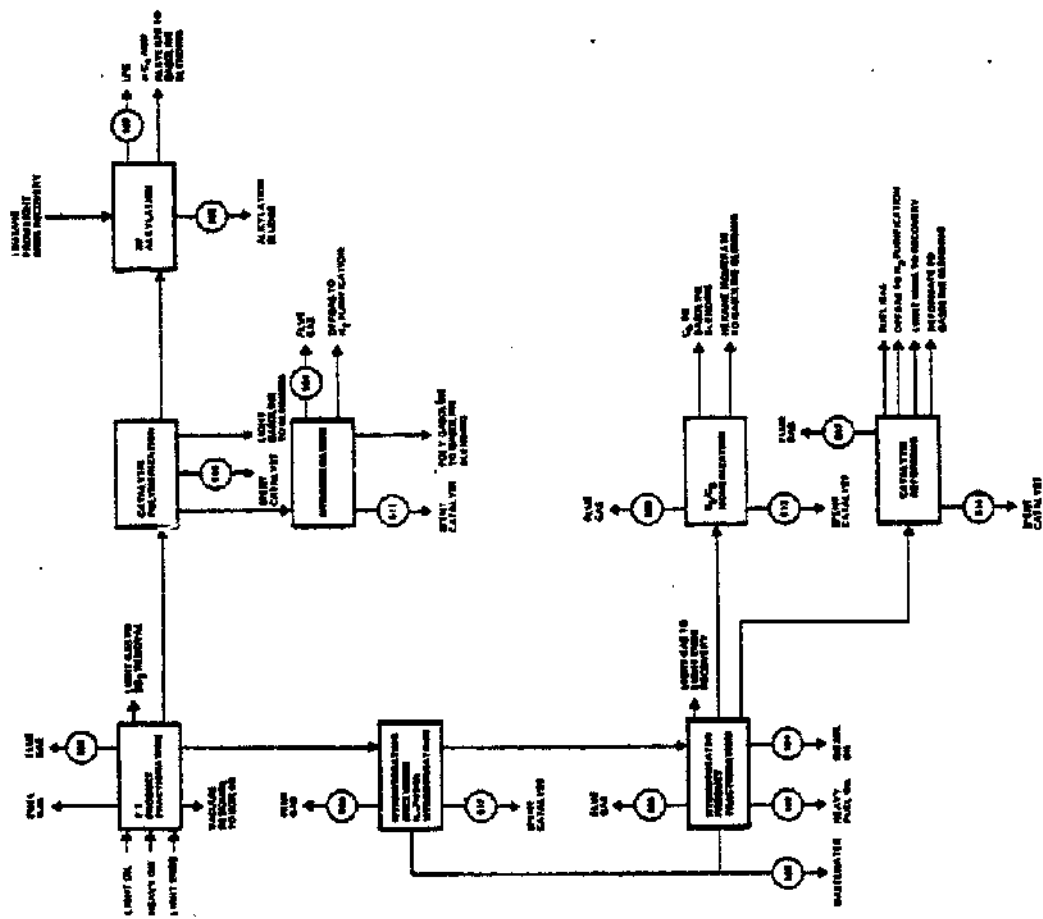
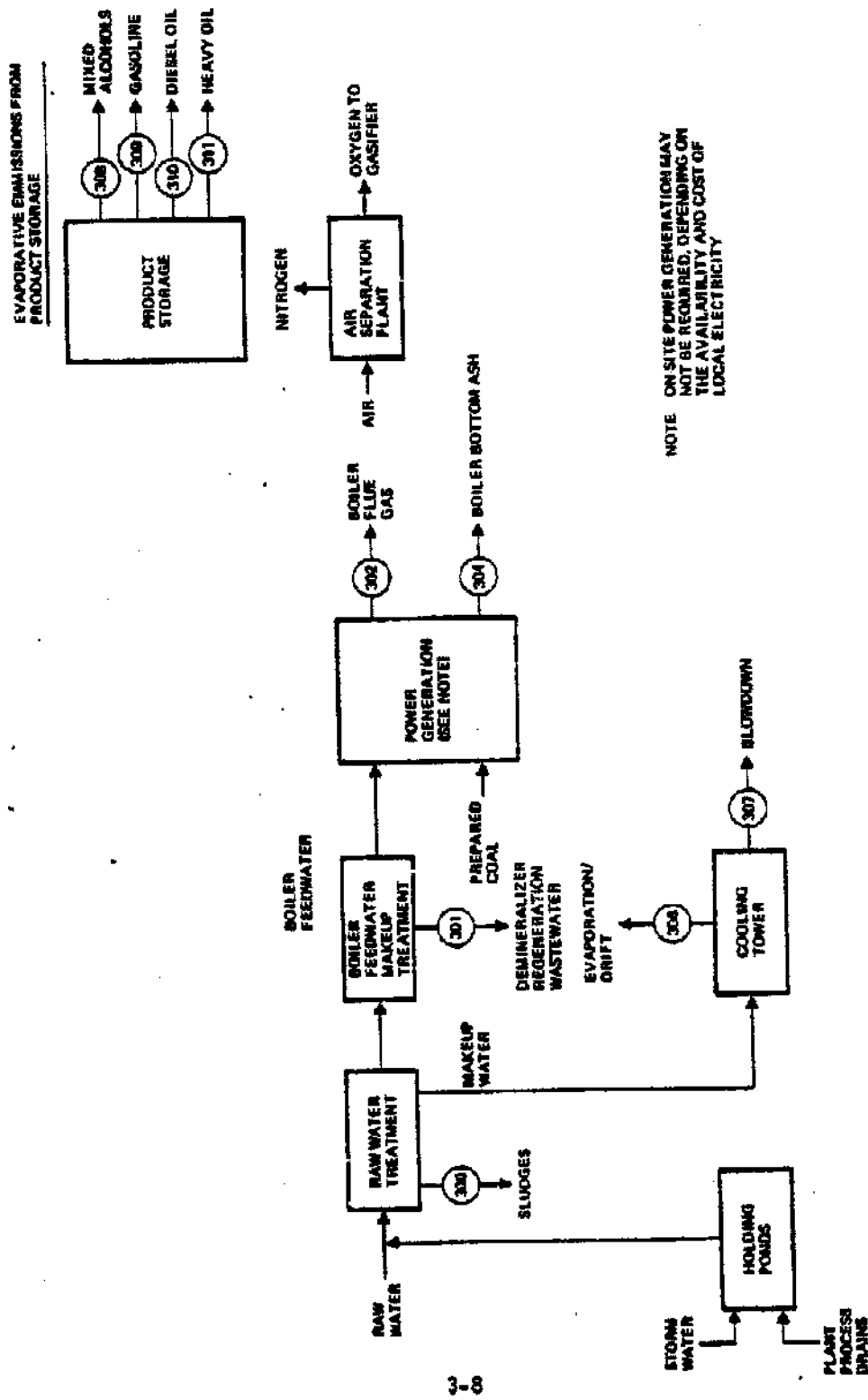Figure 3-3. Fischer-Tropsch Product Fractionation and Upgrading

Figure 3-4. Auxiliary processes associated with K-T based indirect liquefaction facilities

Talcher, India) employ four-headed gasifiers which resemble two intersecting ellipsoids with burners located 90 degrees apart at each of the four apices. Coal is introduced continuously into the gasifier through screw feeders at the burner heads and then entrained in a stream of low pressure steam and high purity oxygen. Partial oxidation reactions occur rapidly within the central portion of the gasifier; coal residence time is less than a second. Raw product gas and entrained dust exit the gasifier vertically upward through a waste heat boiler system producing high pressure saturated steam. Molten slag exits the bottom of the gasifier and falls into a quench tank where circulating cooling water causes it to shatter into granular form. Slag is removed from the quench tank by a drag chain conveyor on which dewatering occurs prior to subsequent slag disposal.

The principal waste stream associated with the gasification operation is quenched slag (Stream 207). K-T slag is a coarse, pebble sized material which is physically stable and essentially inert. Quenched slag has about the same composition as the parent coal ash and retains about 10% moisture. Depending upon the quench water quality, and whether the slag is rinsed, contaminants such as NH_4^+ and SCN^- may be present in the slag moisture.

3.1.3 Gas Purification and Upgrading

The gas purification and upgrading operation consists of: (1) gas cooling and dust removal; (2) NO_x reduction; (3) raw gas compression and cooling; (4) cyanide washing; (5) shift conversion; (6) acid gas removal; and (7) trace sulfur removal.

Gas Cooling and Dust Removal

Hot raw gas from the waste heat boiler is cooled and scrubbed of entrained dust in two stages by means of direct water contacting. Final de-dusting is provided by a wet electrostatic precipitator. The collected dust slurry is pumped to settling basins for thickening. Most of the clear water overflowing the settlers is indirectly cooled and recycled. The settler underflow is filtered to produce dewatered dust (up to 50% moisture) and filtrate which is combined with a portion of the clarifier overflow as blowdown for controlling the buildup of dissolved components within the washer system.

Waste streams associated with the gas cooling and dust removal process are dewaterd dust (Stream 209) and blowdown (Stream 210). Gasification dust consists primarily of coal ash and unreacted carbon. The dust is combustible and has leachable components. In addition, moisture associated with the dust will be similar in composition to the washer blowdown, containing contaminants such as NH_4^+, CN^-, SCN^-, $S_2O_3^=$, $SO_4^=$, Cl^-, and other species.

NO_x Reduction

The NO_x reduction unit catalytically hydrogenates nitrogen oxides and oxygen present in the raw synthesis gas to eliminate associated fouling on compressor blades and in the acid gas removal system. Although such a unit is currently in use at an operating K-T based facility (9), details regarding unit performance and reaction chemistry are not available. The only waste stream expected from this unit is spent cobalt molybdate catalyst (Stream 212) which will periodically require disposal.

Raw Gas Compression and Cooling

Koppers-Totzek technology involves coal gasification at essentially atmospheric pressure. However, downstream operations such as cyanide wash, shift conversion, acid gas removal, and liquid product synthesis are more efficient and economical at elevated pressures. Therefore, raw gas from cooling and dust removal is compressed to about 3 MPa prior to subsequent treatment. The temperature rise of the gas during compression is controlled by intercoolers and an aftercooler, consistent with materials limitations and temperature requirements of downstream processes.

The principal waste stream from raw gas compression and cooling is compression condensate (Stream 211). Contaminants expected to be present in the condensate include NH_4^+, Cl^-, $S^=$, SCN^-, and CN^-.

Cyanide Wash

Hydrogen cyanide and any residual ammonia present in the raw synthesis gas are removed by absorption in cold methanol. Rich methanol from the absorber is regenerated by depressurization and indirect heating to also yield a sour flash gas. Water vapor coabsorbed with the cyanide is recovered from the process methanol by distillation.

The major waste stream associated with a methanol-based cyanide wash process is sour flash gas (Stream 214). Sour flash gas from a methanol-based cyanide wash is expected to consist primarily of H_2S, CO, HCN, CO_2, COS, H_2, and methanol vapor.

Shift Conversion

Gases suitable for feed to Fischer-Tropsch synthesis should have somewhat greater than a 2:1 ratio of H_2 to CO and no more than a few percent CO_2. The H_2 to CO ratio in raw K-T gas typically ranges from 1:2 to 1:2.5, well below the ratio required for liquids synthesis. Thus, a shift conversion step is a necessary part of the gas upgrading. All commercial scale K-T based coal gasification facilities employ a shift conversion unit which follows raw gas sulfur removal and precedes CO_2 removal, and this approach has been incorporated into the base plant design. This approach enables the use of conventional iron-chromium or copper-zinc shift catalysts. Also, due to the favorable H_2S to CO_2 ratio before shift conversion, it facilitates production of an H_2S-rich offgas for economic sulfur recovery.

Streams produced by shift conversion are spent shift catalyst (Stream 217) which periodically requires replacement and shift condensate blowdown which is reused as makeup water to the gasification quench circuit.

Acid Gas Removal

Removal of H_2S and other sulfur compounds present in the raw K-T gas is necessary to prevent catalyst poisoning in subsequent shift conversion, and Fischer-Tropsch synthesis operations. Bulk removal of CO_2 is necessary to obtain a composition meeting the stoichiometric requirements for synthesis feed gas. The two-stage selective Rectisol acid gas removal process has been included in the base plant design, since all commercial scale K-T based coal gasification facilities utilize two-stage selective Rectisol units and the only K-T based indirect liquefaction facility proposed in the U.S. (The North Alabama Coal Gasification Consortium Project) is also expected to use this process.

Rectisol is a physical absorption process using low temperature methanol as a solvent. In two-stage selective Rectisol systems, sulfur compounds are removed from the raw gas prior to shift conversion and subsequent CO_2 removal.

This facilitates high process selectivity due to the favorable H_2S to CO_2 ratio before shift conversion. Sulfur laden methanol from sulfide absorption is enriched by flashing and stripping a portion of the absorbed CO_2 and then regenerated in a hot stripper to produce a sulfur-rich offgas (Stream 216) typically containing 25 to 35% H_2S. Carbon dioxide laden methanol from the CO_2 absorber is regenerated by flashing and stripping with N_2 to produce a CO_2-rich offgas (Stream 219). An additional waste stream from the Rectisol system is still bottoms (Stream 220) from a methanol/water distillation unit which controls moisture buildup in the methanol solvent.

Trace Sulfur Removal

To protect synthesis catalysts from sulfur poisoning, zinc oxide guard beds may be used following the Rectisol process to remove residual traces of sulfur compounds. Ordinarily the Rectisol process can attain levels of less than 0.1 ppmv total sulfur species in the synthesis feed gas, but ZnO provides for temporary removal during periods of Rectisol process upsets. Periodically, sulfur guard material must be decommissioned and replaced. This generates a solid waste (Stream 221) consisting of spent ZnO/ZnS.

3.1.4 Product Synthesis

Hydrocarbon production via Fischer-Tropsch (F-T) synthesis can be represented by the following reaction:

$$nCO + (2n + 0.5x) H_2 \rightarrow C_nH_{2n+x} + nH_2O + heat$$

where n ranges from 1 to about 20, x = 2 for paraffins and x = 0 for olefins. The mix of F-T products obtained (i.e., the range of n and x values) is dependent upon several factors including the reactor design, temperature, pressure, and type of catalyst used. Synthesis gas usually contains some CO_2 in addition to CO and H_2. Because synthesis catalysts are also active for the hydrogenation of CO_2, the presence of CO_2 does not create problems as long as the synthesis gas contains the proper ratio of $H_2/(CO + CO_2)$. F-T synthesis proceed over iron-based catalysts at 600K and 2.3 MPa (fluidized bed reactors) or 500K and 2.7 MPa (fixed bed reactors)[18].

The crude liquid fuel products will require upgrading (probably onsite) to yield final products which are marketable as substitutes for petroleum-

derived fuels. This is particularly true for motor gasolines, where crude coal-derived gasoline fractions would not meet octane requirements for the retail market in the U.S. F-T products could be upgraded by catalytic alkylation of the C_3-C_4 fraction to yield gasoline-blend hydrocarbons and commercial grade LPG by hydrotreating for destruction of olefins and oxygenated organics, by catalytic reforming to provide more cyclic and branched chain hydrocarbons, by C_5/C_6 isomerization to increase the anti-knock quality of pentanes and hexanes, and by catalytic polymerization to convert propene/butene fractions into higher molecular weight gasoline blending compounds. All of these upgrading processes will utilize conventional petroleum refinery technology and have been included in the base plant. It should be noted, however, that the specific upgrading processes employed will depend largely on the desired product characteristics.

Synthetic liquid fuels synthesis generates a purge gas containing compounds such as unreacted carbon oxides, hydrogen, methane, and methanol. Several options are available to handle the purge gas including use as an on-site fuel, reforming to generate additional synthesis gas, or conversion of the residual hydrogen and carbon oxides into methane to produce SNG. Because supplemental fuel ma·· ⌐equired for power generation, use of these purge gases as an on-site f ↓   ⁺ selected for analysis purposes. In actual practice, the decision regardi..ₗ the disposition of synthesis purge gases involves site- and design-specific considerations which are outside the scope of this study.

Product synthesis and upgrading generates a variety of waste streams. Gaseous waste streams include CO_2 offgas from SNG purification (Stream 239), SNG dehydration offgases (Stream 240), and flue gases from process heaters (Streams 502 to 507). The principal aqueous waste stream is the F-T wastewater (Stream 223), although smaller amounts of organic-containing wastewaste (Stream 508) are generated by product upgrading. Synthesis and upgrading catalysts periodically require replacement and, in some cases, require disposal. Since HF alkylation has been included in the base plant, a small volume alkylation sludge (Stream 509) will be generated.

3.1.5 Auxiliaries

The major additional auxiliary processing units required for self-sufficient K-T based synfuels facilities are: 1) on-site boiler for power generation; 2) makeup water treatment facilities; 3) process cooling water system; 4) liquid product/by-product storage facilities; and 5) oxygen production unit.

The most significant potential source of waste streams from the auxiliary processes is the boiler. The boiler flue gases (Stream 302) are particularly important because the boilers will generally be coal-fired and are therefore potentially major sources of SO_x, NO_x, and particulate emissions. In addition to flue gases, waste streams resulting from the boilers include blowdown condensates (Stream 303) and bottom ashes (Stream 304). It should be again noted that most plants are potentially self-sufficient with respect to steam and, depending upon the local availability and cost of electric power, an on-site power boiler may not be needed.

The major waste streams from makeup water treatment are sedimentation pond sludges and lime/soda softener sludges (Stream 300), and demineralizer regeneration wastewaters (Stream 301) from the boiler feedwater treatment unit. Evaporated volatiles and drift (Stream 306), and cooling tower blowdown (Stream 307) are the major waste streams from the cooling water system. Evaporative emissions (Streams 308 through 311) are the major waste streams from product/by-product storage facilities.

The oxygen plant itself is not a major source of waste streams. However, as a major consumer of energy, it impacts the magnitude of the waste streams produced in other units, particularly in the steam/power generation unit and the cooling water system.

3.1.6 Fugitive and Miscellaneous Wastes

In addition to the waste streams associated with specific processes, there are wastes which are of non-specific origins such as fugitive organic emissions (Stream 241). There are many potential sources of fugitive organic emissions in an indirect coal liquefaction plant. These include pumps, compressors, valves, flanges, and pressure relief devices.

3.2 POLLUTION CONTROL

At the present time, no K-T based indirect liquefaction plants are opera-
ting in the United States, although the K-T process is widely used in other
countries for the production of hydrogen (primarily for ammonia) and fuel gas.
The emphasis on pollution control which has been incorporated into designs
for facilities abroad is generally less than that which is anticipated for
U.S. facilities. Thus, directly applicable performance data for most pollu-
tion control technologies are quite limited. The potential applicability of
most pollution control technologies to waste streams identified in Section
3.1 has, therefore, been inferred from their use in similar applications in
industries such as petroleum refining, coke production, natural gas process-
ing, coal cleaning, and electrical utilities. This section identifies the
pollution control technologies selected for evaluation. These technologies
reflect the types of alternatives which are under consideration for facilities
in the U.S. It should be noted, however, that a variety of control tech-
nologies with similar performance characteristics are potentially applicable
to most waste streams identified in Section 3.1.

3.2.1 Air Pollution Control

Pollution control technologies considered for gaseous waste streams
presented in Section 3.1 are summarized in Table 3-3, along with the secondary
waste streams generated by the control technologies. Also included in the
table are the pollution control technologies considered for gaseous secondary
waste streams. As shown in the table, the sour flash gas from cyanide wash
(Stream 214), the H_2S-rich offgas (Stream 216), and the sour stripper offgas
(Stream 441) are combined for treatment in a common sulfur recovery system.
For evaluation purposes, emissions from the coal-fired thermal dryers
(Stream 206) are assumed to be combined with the flue gas from power genera-
tion (Stream 302) for common treatment since the characteristics of these
two streams are essentially identical; however, in practice, these streams
may be controlled separately. All other streams are controlled individually
by methods commonly applied to analogous wastes in other industries. All
the control technologies considered are commercially available, proven pro-
cesses that have been employed in either coal-fired power plants or petroleum
refineries.

TABLE 3-3. POLLUTION CONTROL TECHNOLOGIES FOR GASEOUS WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
200	Fugitive dust from material storage	Vegetative and chemical stabilization	None
202-205	Fugitive particulates from material conveying and processing	Enclosure, hoods and fabric filters	None
206	Emissions from thermal dryers	See Stream 302	See Stream 302
214	Sour flash gas from cyanide wash	This stream combined with the H_2S-rich acid gas (Stream 216) and sour stripper offgas (Stream 441) for treatment in Claus bulk sulfur removal, SCOT tailgas treatment and thermal incineration	Spent Claus catalyst (Stream 442); SCOT sour condensate (Stream 449); spent SCOT catalyst (Stream 418); incinerated SCOT tailgas (Stream 423)
216	H_2S-rich offgas	See Stream 214	See Stream 214
218	CO_2-rich acid gas	None	None
229	CO_2 offgas from SNG purification	Thermal incineration	Incinerated CO_2 offgas (Stream 429)
240	SNG dehydration offgas	None	None
241	Fugitive organic emissions from process equipment	Leak detection and repair methods	None
302	Flue gases from power generation	Electrostatic precipitator for particulate control and limestone scrubbing for SO_2 control	Boiler flyash (Stream 423); FGD sludge from limestone scrubbing (Stream 424); treated boiler flue gas
306	Cooling tower evaporation and drift	None	None
308	Evaporative emissions from mixed alcohol storage	Floating roof tank with primary and secondary seals	None

(Continued)

TABLE 3-3. CONTINUED

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
310	Evaporative emissions from diesel oil storage	Fixed roof tank with internal floating roof with closure seals	None
311	Evaporative emissions from fuel oil storage	Fixed roof tank with internal floating roof with closure seals	None
413	Flue gas from fluidized bed boiler	Limestone injection for SO_2 control and cyclones and electrostatic precipitators for particulate control	Treated FBC flue gas (Stream 435), spent bed media (Stream 414), FBC fly-ash (Stream 442)
441	Sour stripper offgas	See Stream 214	See Stream 214
502-587	Flue gas from process heaters	None	None

aThese flue gases include emissions from thermal drying (Stream 206) since coal-fired thermal dryers are employed.

3-17

3.2.2 Wastewater Treatment

Pollution control technologies considered for wastewater streams are presented in Table 3-4. The principal wastewater streams in terms of loading of gasification- or synthesis-generated contaminants are the cooling and dust removal blowdown (Stream 210), the F-T wastewater (Stream 223), the raw gas compression and cooling condensate (Stream 211) and the upgrading wastewater (Stream 508). These streams are combined with the Rectisol condensate/still bottoms (Stream 211) for common treatment. Two treatment alternatives were considered for these streams: 1) activated sludge followed by filtration, granular activated carbon adsorption and discharge to surface waters; and 2) activated sludge followed by cooling tower concentration and discharge to a surface impoundment. Other wastewater streams indicated in the table are essentially identical to wastes generated by coal-fired power plants or refineries and are not unique to synfuel facilities. These streams are likely to be treated individually.

3.2.3 Solid Waste Management

Based upon solid waste management practices currently applied in the synfuels and other industries, and those being considered for proposed synfuels plants, many of the solid wastes will be landfilled. As indicated in Table 3-5, the major solid waste stream, dewatered K-T dust (Stream 209), is burned in a fluidized bed combustion (FBC) boiler to recover its energy value and reduce the solid waste volume. A limited number of spent catalysts (e.g., nickel, cobalt, and platinum-based catalysts) are recycled to their respective vendors for metal recovery or reprocessing and reuse.

3.3 SOURCE TERM ESTIMATES FOR WASTE STREAMS

This section presents source term estimates for Risk Analysis Units (RAUs) in both uncontrolled waste streams and discharge streams after waste treatment. The RAU categories considered have been previously listed in Section 1. Data sources for characterizing uncontrolled waste streams from the K-T based F-T synfuels facility and for estimating control technology performance are briefly described in Section 3.3.1. Source term estimates for gaseous waste streams, aqueous waste streams, and solid waste streams are presented in Section 3.3.2, 3.3.3, and 3.3.4, respectively. Where data are available, source terms estimates are presented in ranges.

TABLE 3.4. POLLUTION CONTROL TECHNOLOGIES FOR AQUEOUS WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
201	Raw coal storage runoff	Sedimentation and neutralization	Sedimentation sludge
210	Cooling and dust removal blowdown	Control Option 1 Activated sludge and filtration and granulated activated carbon	Activated sludge waste (Stream 415), discharge to surface waters (Stream 416)
211	Raw gas compression and cooling condensate	Control Option 2 Activated sludge and cooling tower concentration and surface impoundment	Activated sludge waste (Stream 415), cooling tower evaporation and drift (Stream 306), discharge to surface impoundment (Stream 437), leachate
220	Rectisol condensate/still bottoms		
223	F-T wastewater		
508	Upgrading wastewater		
305	Demineralizer regeneration wastewater	Neutralization	None
307	Cooling tower blowdown	Sedimentation and neutralization	Sedimentation sludge
409	SCOT sour condensate	Steam stripping	Sour stripper offgas (Stream 441)

TABLE 3-5. POLLUTION CONTROL TECHNOLOGIES FOR SOLID WASTE STREAMS

Stream Number	Stream Description	Control Technology Considered	Secondary Waste Streams Generated
207	Quenched slag	Landfill	Leachate
209	Dewatered K-T dust	Combustion in fluidized bed boiler	Flue gas from fluidized bed boiler (Stream 113), spent bed media (Stream 114)
212	Spent NO$_x$ catalyst	Landfill	Leachate
217	Spent shift catalyst	Landfill	Leachate
221	Spent sulfur guard	Landfill	Leachate
222	Spent F-T catalyst	Landfill	Leachate
238	Spent methanation catalyst	Off-site catalyst reclamation	None
300	Raw water treatment sludges	Landfill	Leachate
304	Boiler bottom ash	Landfill	Leachate
402	Spent Claus catalyst	Landfill	Leachate
410	Spent SCOT catalyst	Off-site catalyst reclamation	None
414	Spent bed media from FBC	Landfill	Leachate
415	Activated sludge solid waste	Landfill	Leachate
423	Boiler flyash	Landfill	Leachate
442	FBC flyash	Landfill	Leachate
424	FGD sludge from limestone scrubbing	Fixation followed by landfill	Leachate
470	Miscellaneous sedimentation/ treatment sludges	Landfill	Leachate
509	Alkylation sludge	Neutralization followed by landfill	Leachate
510	Spent polymerization catalyst	Landfill	Leachate
511	Spent hydrogenation catalyst	Offsite catalyst reclamation	None
512	Spent hydrotreating catalyst	Offsite catalyst reclamation	None
513	Spent isomerization catalyst	Offsite catalyst reclamation	None
514	Spent reforming catalyst	Offsite catalyst reclamation	None

For the majority of the waste streams, only a single number is presented for each RAU representing a specific set of design/operating conditions. A single number does not imply a high accuracy for source term estimates but, rather, reflects the absence of data for estimating the influence of varying design/operating conditions. Uncertainties in and limitations of the source term estimates presented in this section are presented in Section 3.4.

3.3.1 Data Sources for Stream Characterization and Control Performance Estimates

The major sources of data used to develop base plant/process configurations and to define the types and characteristics of uncontrolled waste streams were: 1) test programs at the K-T gasification facility at Modderfontein, S.A. (6,9,10); 2) a test program at the K-T facility at Ptolemais, Greece (4,11,12,13); 3) Linde/Lotepro research and tests at Rectisol installations (14,15,16,17); 4) gasoline-from-coal research studies conducted by Mobil Research and Development Corporation (18); and 5) permit filings, environmental impact statements, and design studies for various proposed K-T based domestic synthetic fuel facilities (19,20,21,22,23).

Characteristics of treated waste streams depend largely upon the performance of the control technologies employed. Data sources used to estimate control performance include published performance data, contacts with control equipment vendors, information on experience with the control technologies in related conventional industries, experimental data regarding the performance of controls on K-T gasification waste streams, and engineering evaluations. Since essentially none of the control technologies considered have been routinely employed in K-T gasification or F-T facilities, some extrapolation has generally been required in projecting control performance as a K-T based F-T facility.

3.3.2 Source Term Estimates for Gaseous Waste Streams

Source term estimates for uncontrolled and controlled gaseous waste streams are presented in Tables 3-6 and 3-7, respectively. Uncontrolled fugitive dust (Stream 200) and fugitive particulate (Streams 202 through 205) emissions estimates were based upon published emissions data from other industries with similar coal handling/preparation operations (24,25,26).

TABLE 3-6. SOURCE TERM ESTIMATES FOR UNCONTROLLED GASEOUS WASTE STREAMS

		Waste Stream Generation Rate, kg/hr						
RCRA Analysis Units	200 Fugitive Dust	202-205 Fugitive Particulate	206 Emissions from Thermal Dryer	214 Flash Gas from MEA Wash	216 H₂S-Rich Offgas	218 CO₂ Vent Gas	220 CO₂ from SRU Purification
Carbon monoxide	●	○	●	154	Trace	1000	0.14
Sulfur oxides	●	○	●	○	23	○	○
Nitrogen oxides	●	○	●	○	0	○	○
Acid gases	●	○	●	1100	28000	6.7	○
Alkaline gases	●	○	●	Trace	Trace	70	230
Hydrocarbon gases	●	●	●	Trace	Trace	○	○
Formaldehyde	●	○	●	○	○	○	○
Volatile organochlorines	●	●	●	●	●	●	●
Volatile carboxylic acids	●	●	●	●	●	●	●
Volatile SAS heterocyclics	●	●	●	●	●	●	●
Volatile N-heterocyclics	●	●	●	●	●	●	●
Benzene	●	●	●	●	●	●	●
Aliphatic/alicyclic	○	●	●	●	●	●	●
Mono/diaromatic hydrocarbons (including benzene)	○	○	●	●	●	●	●
Polycyclic aromatic hydrocarbons	○	○	●	●	●	●	●
Aliphatic amines (excluding N-heterocyclics)	○	○	○	●	○	○	○
Aromatic amines (excluding N-heterocyclics)	○	○	○	●	○	○	○
Alkaline nitrogen heterocyclics ("azarenes") (excluding "volatiles")	○	○	○	●	●	●	●
Neutral N, O, S heterocyclics (excluding "volatiles")	○	●	○	●	●	●	●
Carboxylic acids (excluding "volatiles")	●	●	●	●	●	●	●
Phenols	○○	○○	●●	●●	●●	○○	●●
Aldehydes and ketones (excluding formaldehyde)							
Monoaromatic organics	○	●	●	120	6300	18	●
Sulfur	●	●	●	95	63	350	○
Alcohols	●	●	●	○	●	○	○
Nitroaromatics	●	●	●	○	●	○	○
Ethers	●	●	●	○	●	●	○
Amides	●	●	●	○	●	●	○
Nitriles	●	●	●	○	●	●	○
Respirable particles	8.2e-05	450-7400	1600	○	●	○	○
Arsenic	8.6×10⁻⁵	4.5×10⁻⁵-0.0079	0.0016	○	●	●	○
Mercury	9.3×10⁻⁶	5×10⁻⁴-0.0063	0.0017	○	●	●	○
Nickel	0.0012	0.004-0.10	0.022	○	●	○	○
Calcium	<3.4×10⁻⁵	<0.0030	<1.3×10⁻⁵	○	●	●	○
Lead	8.5×10⁻⁴	0.0045-0.074	0.045	○	●	●	○
Other trace elements	○	○	NOT AVAILABLE	○	●	●	○
Radioactive materials	○	○	○	○	●	●	○
Other remaining materials	○	○					

(Continued)

TABLE 3-6. SOURCE TERM ESTIMATES FOR UNCONTROLLED GASEOUS WASTE STREAMS

	240 Sx: Deaeration Offgas	241 Fugitive Organics From Process Equipment	302 Flue Gas From Power Generation	308 Evaporative Emissions From Alcohol Storage	309 Evaporative Emissions From Gasoline Storage
Risk Analysis Units			Waste Stream Generation Rate, kg/hr		
1 Carbon monoxide			590		
2 Sulfur oxides			16000		
3 Nitrogen oxides			1800-2000		
4 Acid gases					
5 Alkaline gases		350	44		
6 Hydrocarbon gases					
7 Formaldehyde					
8 Volatile organochlorines					
9 Volatile carboxylic acids					
10 Volatile gas halocarylics					
11 Volatile N-heterocyclics					
12 Benzene		7.3x10⁻⁴			7.1-7.5
13 Aliphatic/alicyclic		84	0.024		1.4-1.5
14 Mono/diaromatic hydrocarbons (excluding benzene)		35			
15 Polycyclic aromatic		0.037	0.010	0	
16 Nitrosamines					
17 Aliphatic amines (excluding N-heterocyclics)					
18 Aromatic amines (including N-heterocyclics)					
19 Alkaline nitrogen hetero-cyclics ("azaarenes") (excluding "volatiles")					
20 Neutral N, O, S hetero-cyclics (excluding "volatiles")					
21 Carboxylic acids					
22 Phenols		8.7	0.73	0.53-0.70	
23 Aldehydes and ketones ("carbonyls") (excluding formaldehyde)					
24 Monocarbocyclic organo sulfur		28		2.2-2.9	
25 Alcohols			1200		
26 Ethers/esters			0.23		
27 Esters			0.32		
28 Amines			3.22		
29 Nitriles			-0.092		
30 Tars			2.3		
31 Respirable particles			NOT AVAILABLE		
32 Arsenic			0.39-0.78		
33 Mercury					
34 Nickel					
35 Cadmium					
36 Lead					
37 Other trace elements					
38 Radioactive materials					
39 Other remaining materials					

(Continued)

TABLE 3-6. CONTINUED

Waste Stream Generation Rate, kg/hr

	30b Evaporation Emissions from Diesel Oil Storage[f]	311 Evaporative Emissions from Fuel Oil Storage[f]	413 Flue Gas from FGC	441 Sour Stripper BFFGas	306 Cooling Tower Evaporation and Drift (Option 2, Option 1)	502-507 Flue-Gas from Process Heaters
1 Carbon monoxide	0	0	.13	0	0	4.3
2 Sulfur oxides	0	0	3100	0	0	26
3 Nitrogen oxides	0	0	200	0	0	0
4 Acid gases						
5 Alkaline gases						
6 Halocarbon gases						
7 Formaldehyde						
8 Volatile organochlorines	9.8x10⁻⁶-1.6x10⁻⁵			0.87	0.023-0.032 0.0010	1.7
9 Volatile carboxylic acids	0.16-0.25	0.0012-0.0022		0.029	0.22 0.0027	
10 Volatile OAS heteroorganics	0.048-0.077	9.3x10⁻⁴-0.0016				
11 Volatile N-heteroorganics						
12 Benzene	0.0013-0.0027	1.7x10⁻⁵-3.0x10⁻⁵				
13 Aliphatic/alicyclic						
14 Mono/Aromatic hydrocarbons						
15 Polycyclic aromatic				0	1-0 0	0
16 Aliphatic amines (excluding	0	0	0	0	<2.1x10⁻⁴	0
17 Aromatic amines (excluding	0	0	0	0	0	0
18 Nitrites nitrogen hetero-	0	0	0	0	0	0
19 Neutral N, O, S hetero	0	0	290	0	0	1.1-3.2
20 Carboxylic acids	0	0	0.33	0	<2.1x10⁻⁵	0
21 Phenols	0	0	1.1	0		0
22 Aldehydes and ketones	0	0	<1.0	0		0
23 Nonheterocyclic organo	0	0	<0.09	0	0.0004	0
24 Sulfide	0	0	0.98	0		0
25 Alcohols						
26 Nitroaromatics						
27 Esters						
28 Amides						
29 Nitriles						
30 Tars						
31 Respirable particles					1.8x10⁻⁶-8.014 1.8x10⁻⁴	
32 Arsenic					4.9x10⁻⁵-6.3x10⁻⁵ 4.5x10⁻⁵	
33 Mercury					0.013 0.0013	
34 Nickel					2.8x10⁻⁴-4.2x10⁻⁸ 2.6x10⁻⁴	
35 Cadmium					9.3x10⁻⁴-0.0014 9.3x10⁻⁴	
36 Lead			NOT AVAILABLE			
37 Other trace elements	0	0		0	0	0
38 Radioactive materials (mCi/hr)	0	0		0	0	0
39 Other remaining materials						

[a] Includes sulfur component of the emissions only. Gaseous constituents are included in the flue gases from power generation. (Stream 302).

[b] A small quantity of methane and glycol could be present in this stream although no basis exists for estimating the emission rates.

[f] Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

TABLE 3-7. SOURCE TERM ESTIMATES FOR CONTROLLED GASEOUS WASTE STREAMS

Risk Analysis Units	Waste Stream Generation Rate, kg/hr					
	200 Fugitive Dust	202-705 Fugitive Particulate	705 Dust from Thermal Dryer	708 Incinerated CO$_2$ Offgas	241 Fugitive Organic Emissions from Process Equipment	707 Flue Gas from Power Generation
1 Carbon monoxide	0	0	0	2.0	0	150
2 Sulfur oxides	0	0	0	0	0	2000
3 Nitrogen oxides	0	0	0	0	0	1680-2300
4 Acid gases	0	0	0	0	0	0
5 Alkaline gases	0	0	0	0	0	0
6 Hydrocarbon gases	0	0	0	0.59	70-90	44
7 Formaldehyde	0	0	0	0	0	0
8 Volatile organochlorines	0	0	0	0	0	0
9 Volatile carboxylic acids	0	0	0	0	0	0
10 Volatile O&S heterocyclics	0	0	0	0	0	0
11 Volatile N-heterocyclics	0	0	0	0	0	0
12 Ketones	0	0	0	0	0	0
13 Aliphatic/alicyclic	0	0	0	0	0	0
14 Mono/Diaromatic hydrocarbons (excluding benzene)	0	0	0	0	2.4x10^{-5}-1.0x10^{-4}	0.024
15 Polycyclic aromatic hydrocarbons	0	0	0	0	22-28 / 9.2-12	0.010
16 Aliphatic amines (excluding N-heterocyclics)	0	0	0	0	0.0076-0.037	0
17 Aromatic amines (excluding N-heterocyclics)	0	0	0	0	0	0
18 Nitrogen heterocyclics ("azaarenes") (excluding "volatiles")	0	0	0	0	0	0
19 Sulfur & O$_2$,S heterocyclics (excluding "volatiles")	0	0	0	0	0	0
20 Carboxylic acids (excluding "volatiles")	0	0	0	0	0	0
21 Phenols	0	0	0	0	1.7-2.1	0.73
22 Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	0	0	0	0	0
23 Nonheterocyclic organo	0	0	0	0	7.3-9.0	0
24 Sulfur	0	0	0	0	0	0
25 Alcohols	0	0	0	0	0	0
26 Nitroaromatics	0	0	0	0	0	0
27 Esters	0	0	0	0	0	0
28 Amides	0	0	0	0	0	0
29 Nitriles	0	0	0	0	0	0
30 Tars / Respirable particles	0.42-0.5	95-220	0	0	0	81-270
31	0	0	8.7x10^{-6}	0	0	0.0049-0.013
32 Arsenic	9.5x10^{-6}	1.5x10^{-5}-2.2x10^{-4}	9.4x10^{-8}	0	0	0.32
33 Mercury	9.3x10^{-6}	5.0x10^{-5}-2.5x10^{-4}	1.2x10^{-8}	0	0	0.056-0.16
34 Nickel	1.2x10^{-4}	8.4x10^{-4}-0.031	<3.5x10^{-6}	0	0	<0.0053
35 Cadmium	<3.4x10^{-6}	<0.3x10^{-3}	-3.5x10^{-6}	0	0	0.040-0.13
36 Lead	8.5x10^{-5}	4.5x10^{-3}-0.0022	8.7x10^{-5}	0	0	0.08-1.6
37 Other trace elements	0.0024	0.013-0.064	0.0095	0	0	0.39
38 Radioactive materials (mCi/hr)	0	0	0	0	0	0
Other remaining materials	0	0	0	0	0	0

(Continued)

TABLE 3.7. CONTINUED

Waste Stream Generation Rate, lbs/hr

Risk Analysis Units	386 Evaporative Emissions from Alcohol Storage	389 Evaporative Emissions from Gasoline Storage	391 Evaporative Emissions from Diesel Oil Storage	311 Evaporative Emissions from Fuel Oil Storage	418 Flue Gas from FBC
1 Carbon monoxide	o	o	o	o	33
2 Sulfur oxides	o	o	o	o	310
3 Nitrogen oxides	o	o	o	o	200
4 Acid gases	o	o	o	o	o
5 Alkaline gases	o	o	o	o	o
6 Hydrocarbon gases	o	o	o	o	o
7 Formaldehyde	o	o	o	o	o
8 Volatile organochlorines	o	o	o	o	o
9 Volatile carboxylic acids	o	o	o	o	o
10 Volatile OES heterocyclics	o	o	o	o	o
11 Volatile N-heterocyclics	o	o	o	o	o
12 Benzene	o	0.42-0.51	7.7×10^{-7}	$3.1 \times 10^{-6} - 2.6 \times 10^{-4}$	o
13 Aliphatic/Alicyclic	o	0.066-0.10	0.012 / 0.0038	$7.8 \times 10^{-5} - 1.3 \times 10^{-4}$	o
14 Mono/diaromatic hydrocarbons (excluding benzene)	o				o
15 Polycyclic aromatic	o	o	3.3×10^{-4}	$1.5 \times 10^{-5} - 3.5 \times 10^{-6}$	o
16 Aliphatic amines (excluding heterocyclics)	o	o	o	o	o
17 Aromatic amines (excluding heterocyclics)	o	o	o	o	o
18 N-heterocyclics	o	o	o	o	o
18 Alkaline nitrogen heterocyclics ("azaarenes")	o	o	o	o	o
19 Neutral N, O, S heterocyclics (excluding "volatiles")	o	o	o	o	o
20 Carboxylic acids (excluding "volatiles")	o	o	o	oo	o
21 Phenols	0.010-0.014	o	o	o	o
22 Aldehydes/ketones ("carbonyls") (excluding formaldehyde)	o	oo	o	oo	o
23 Monoheterocyclic organo	o	o	o	o	o
24 Sulfur	0.042-0.058	o	o	o	o
25 Alcohols	o	o	o	o	o
26 Bituminous	o	o	o	o	o
27 Esters	o	o	o	o	o
28 Amides	o	o	o	o	o
29 Nitriles	o	o	o	o	o
30 Tars	o	o	o	o	o
30 Respirable particles	o	o	o	o	35-40
31 Arsenic	o	o	o	o	0.0043-0.013
32 Mercury	o	o	o	o	1.1
33 Nickel	o	o	o	o	0.016-0.040
34 Cadmium	o	o	o	o	<0.0030
35 Lead	o	o	o	o	0.024-0.021
36 Other trace elements	o	o	o	o	0.2-0.72
37 Radioactive materials (mci/hr)	o	o	o	o	o
38 Other remaining materials	o	o	o	o	o

(Continued)

TABLE 3-7. CONTINUED

Bulk Analysis Units	Waste Stream Generation Rate, kg/hr					
	428 Incinerated SCOT Tail Gas	218 CO₂ Vent Gas	240 Dehydration Offgas	306 Cooling Tower Evaporation and Drift Inlet	306 Outlet 2	502-507 Flue Gas From Process Heaters
1 Carbon monoxide	3.8	1000				4.3
2 Sulfur oxides	47					24
3 Nitrogen oxides	7.2-16					
4 Acid gases	0	6.2	0	0.0010	0.023-0.032	1.7
5 Alkaline gases	0	R	0	0.0023	0.22	0
6 Hydrocarbon gases	0	0	0	0	0	0
7 Formaldehyde	0	0	0	0	0	0
8 Volatile organochlorines	0	0	0	0	0	0
9 Volatile carboxylic acids	0	0	0	0	31	0
10 Volatile OBS heterocyclics	0	0	0	0	0	0
11 Volatile N-heterocyclics	0	0	0	0	6.0x10⁻⁵	0
12 Benzene	0	0	0	0	<2.1x10⁻⁴	0
13 Aliphatic/Alicyclic	0	0	0	0	1.2x10⁻⁵	0
14 Mono/Diaromatic hydrocarbons (excluding benzene)						
15 Polycyclic aromatic	0	0	0	0	4.5x10⁻⁶	0
16 Hydrocarbons						
17 Aliphatic amines (excluding S-heterocyclics)	0	0	0	0	0	0
18 Aromatic amines (excluding N-heterocyclics)	0	0	0	0	0	0
19 N-heterocyclics	0	0	0	0	0	0
20 Alkaline nitrogen heterocyclics ("amines")						
21 (excluding "volatiles")	0	0	0	0	0	0
22 Neutral N, O, S heterocyclics (excluding "volatiles")	0	0	0	0	0	0
23 Carboxylic acids (excluding "volatiles")	0	0	0	0	2.5x10⁻⁵	0
24 Phenols	0	0	0	0	2.3x10⁻⁵	0
25 Aldehydes ketones ("carbonyls")(excluding formaldehyde)						
26 Nonaromatic organo sulfur	0	18	0	0	0	0
27 Alcohols	0	350	0	0.0004	0.0004	0
28 Nitroaromatics	0	0	0	0	0	0
29 Esters	0	0	0	0	2.5x10⁻⁵	0
30 Amides						
31 Nitriles						
32 Tars						
33 Respirable particles				3.0x10⁻⁴	1.6x10⁻⁴-0.014	
34 Arsenic				4.9x10⁻⁵	4.9x10⁻⁵-4.3x10⁻⁵	
35 Mercury				0.0013	0.0013	1.1-3.2
36 Nickel				2.5x10⁻⁴	2.8x10⁻⁴-4.2x10⁻⁴	
37 Cadmium				9.7x10⁻⁴	9.7x10⁻⁴-0.0014	
38 Lead				0.015	0.015-2.4	
Other trace elements						
Radioactive materials						
Other remaining materials						

a Small quantity of methane would be present in this stream although no basis exists for estimating the emission rate.

b Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

3-27

Dust and particulate were assumed to have the same composition as the parent coal with respect to ash and trace elements, regardless of particle size. In the case of uncontrolled fugitive dust, the tabulated range of respirable particulate corresponds 5 to 100% of the uncontrolled emission. A fugitive dust control efficiency of 90% was assumed. In the case of uncontrolled fugitive particulate, the tabulated range reflects the published emission range. A fugitive particulate control efficiency of 90% was assumed for the lower level of uncontrolled emissions and a control efficiency of 97% was assumed for the upper level of uncontrolled emissions.

A coal-fired thermal dryer was utilized to provide the 1-2% coal moisture level required for K-T gasification of bituminous coal. Uncontrolled particulate emissions associated with thermal drying are primarily coal-fines carryover which is recovered for gasification. Gaseous constituents of the emissions from thermal drying (Stream 206) are essentially identical in composition to the flue gas from power generation (Stream 302) and similar controls are applicable to both streams. Thus, tabulated emissions from thermal drying include only the coal-fines carryover and emissions of gaseous components are included in the flue gas from power generation. Coal burned in the dryer corresponds to approximately 4% of the coal burned in power generation. All particulate emissions from thermal drying were assumed to be respirable and a particulate control efficiency of 98% was assumed.

Uncontrolled emission estimates for the sour flash gas from cyanide washing (Stream 214), the Rectisol offgases (Streams 216 and 219), and sour stripper offgas (Stream 441) were estimated based primarily upon data published by the developers (14,15,16), information provided by developers (17, 27) and engineering extrapolations. The sour flash gas from cyanide washing, the H_2S-rich offgas (Stream 216) and the sour stripper offgas are combined for common control treatment. An overall sulfur recovery efficiency of about 99.9% has been assumed with essentially complete destruction of HCN, NH_3 and light hydrocarbons. The CO_2-rich vent gas from Rectisol is discharged to the atmosphere without treatment.

Two routine offgases are associated with the product synthesis section: 1) CO_2 from SNG purification (Stream 239); and 2) SNG dehydration offgas (Stream 240). The estimated composition of the CO_2 from SNG purification

was estimated based upon published engineering estimates for SNG production applications (18,28). This stream was assumed to be controlled by thermal incineration producing an incinerated CO_2 offgas (Stream 429) containing 50 ppmv CO and 30 ppmv total hydrocarbons. Although no characterization data are available for the dehydration offgas, this stream may contain small quantities of methane and glycol sorbent. It has been assumed that the dehydration offgas is discharged to the atmosphere without control.

Fugitive organic emissions from process equipment (Stream 241) have been estimated based upon published emission factors for pumps, compressors, valves, flanges and drains (29) and on equipment count for a conceptual F-T facility (19). Fugitive organic emissions from process equipment in gas or vapor service were all assumed to be hydrocarbon gases (RAU category 6). Emissions from process equipment in light liquid service were assumed to be gasoline and mixed alcohols in proportion to the product slate and published composition data for these products (18,30), and is the major contributor to tabulated emissions for RAU categories 13, 14, 22 and 24 in this stream. Emissions from process equipment in heavy liquid service are assumed to have a composition similar to petroleum diesel oil (31) and contributes to tabulated emissions from RAU categories 12, 13, 14 and 15 in this stream. An overall reduction in fugitive organic emissions from process equipment of 72 to 79% was assumed, although higher efficiencies were assumed for light hydrocarbons and lower efficiencies were assumed for heavy hydrocarbons (32).

Emissions associated with the flue gas from power generation (Stream 302) were estimated from material balance calculations and published emission factors for coal-fired utility boilers (33,34). Fly ash was assumed to have the same composition of the whole coal ash except that all mercury in the feed coal is assumed to be volatilized. Approximately 4% of the uncontrolled particulate was assumed to be respirable (34). Ranges in emission estimates for treated flue gas reflect ranges in NSPS control requirements for electric utility and industrial steam generation units. Enrichment of arsenic, nickel, cadmium and lead in the controlled particulate has been assumed, and approximately 73% of the controlled particulate was assumed to be respirable (34).

Evaporative emissions from product and by-product storage (Streams 308 through 311) were based upon published emission factors from other industries (33). The composition of evaporative emissions from alcohol storage and gasoline storage were estimated from published composition data (18,30,45). The composition of evaporative emissions from diesel oil storage was estimated from composition data from petroleum diesel (31). The composition of evaporative emissions from fuel oil storage was estimated assuming that 59% of the emissions were saturates (RAU category 13), 40% were aromatics (RAU category 14) and 1% were polycyclics (RAU category 15) which is consistent with trends in shale-derived residual fuels and petroleum diesel (31). In all cases, evaporative emissions from product and by-product storage were assumed to have the same composition as the bulk liquids. This is a conservative assumption from the risk assessment standpoint because the heavier fractions of the hydrocarbon products, those usually associated with higher risks, have lesser tendency to be evaporated due to their low vapor pressures. Control efficiencies for evaporative emissions from product and by-product storage were assumed to range from 90 to 98% based upon published emissions data from other industries (33). Tabulated ranges in uncontrolled and controlled evaporative emission rates reflect average annual values and maximum values estimated for a facility located in Southwest Illinois.

The composition of flue gas from fluidized bed combustion (Stream 413) of dewatered K-T dust is based upon material balance calculations and published emission factors for coal-fired boilers (33,34). Characteristics of the uncontrolled and controlled flue gas were estimated in a manner similar to that used for flue gas from power generation (Streams 302 and 430).

Sour stripper offgas (Stream 441) characteristics were estimated from sour water composition data provided by the process developer (27). Essentially all dissolved acid and alkaline gases may be stripped from the sour water to produce the stripper offgas and a water of suitable quality for use as makeup water to the on-site boilers.

Under normal operating conditions, negligible quantities of RAU components would be expected in the cooling tower evaporation and drift (Stream 306). However, when the cooling tower is used to concentrate wastewater from wastewater treatment, residual contaminants may be volatilized and/or entrained as drift. Estimates of emissions in cooling tower drift are based

upon electric utility data (47) and wastewater quality estimates (refer to section 3.3.3) and an assumed drift generation rate of 0.01% of the rate of circulation.

Process heater sizes were estimated based upon published designs for F-T facilities (18). Heaters are fired with sulfur-free fuel gas. Flue gas characteristics are based upon AP-42 emission factors for gas-fired commercial heaters (33).

Estimated stack heights, exit velocities and exit temperatures for gaseous waste streams discharged through stacks are presented in Table 3-8. All other streams (e.g., fugitive dust and particulate, fugitive organic emissions and evaporative emissions) are discharged near ground level at low velocities and ambient temperature.

TABLE 3-8. STACK HEIGHT AND EXIT PROPERTIES OF GASEOUS DISCHARGE STREAMS

Stream Number	Stream Description	Stack Height, m*	Exit Velocity, m/sec†	Temperature, K
429	Incinerated CO_2 offgas	46	20	405
302	Flue gas from power generation	76	20	405
413	Flue gas from FBC	76	20	405
428	Incinerated SCOT tail gas	61	20	478
219	CO_2 vent gas	46	20	300
502-507	Flue gas from process heaters	46	20	478

*Stack height information obtained from Reference 35.
†No data on exit velocity are available. Exit velocity was assumed to be 20 m/sec, a typical design velocity for gaseous discharges through stacks.

3.3.3 Source Term Estimates For Aqueous Waste Streams

Source term estimates for uncontrolled and controlled aqueous waste streams are presented in Tables 3-9 and 3-10, respectively. Coal storage pile runoff (Stream 201) flow rates were estimated based upon rainfall data for Southern Illinois. Uncontrolled emission rates for trace elements present in the runoff were based upon limited published concentration ranges (36,46,47). Trace elements in the runoff were conservatively assumed to be removed during neutralization.   3-31

TABLE 3-9. SOURCE TERM ESTIMATES FOR UNCONTROLLED AQUEOUS WASTE STREAMS

Risk Analysis Units	Waste Stream Generation Rate, kg/hr				
	201 Coal Storage Pile Runoff	210 Cooling and Dust Removal Blowdown	211 Compression and Cooling Condensate	220 Rectisol Condensate/Still Bottoms	223 Wastewater
1 Carbon monoxide	o	o	o	o	o
2 Sulfur oxides	o	o	o	o	o
3 Nitrogen oxides	1.5x10⁻⁴	1.2	4.3	0.039	o
4 Acid gases	0.0025	170	47		o
5 Alkaline gases	o	o	o	o	o
6 Hydrocarbon gases	o	o	o	o	o
7 Formaldehyde	o	<0.12	o	o	6300
8 Volatile organochlorines	o	o	o	o	o
9 Volatile carboxylic acids	o	o	o	o	o
10 Volatile O&S heterocyclics	o	o	o	o	o
11 Volatile N-heterocyclics	o	o	o	o	o
12 Benzene	o	<0.12	o	o	o
13 Aliphatic/alicyclic	o	o	o	o	o
14 Mono/diaromatic hydrocarbons (excluding benzene)					
15 Polycyclic aromatic hydrocarbon	o	o	o	o	o
16 Aliphatic amines (excluding N-heterocyclics)	o	o	o	o	o
17 Aromatic amines (excluding N-heterocyclics)	o	o	o	o	o
18 Alkaline nitrogen heterocyclics ("azarenes") (excluding "volatiles")	o	o	o	o	o
19 Neutral N, O, S heterocyclics (excluding "volatiles")	o	o	o	o	o
20 Carboxylic acids (excluding "volatiles")	o	o	o	o	o
21 Phenols	o	<0.0012	o	o	o
22 Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	o	o	o	o	o
23 Nonheterocyclic organms	o	o	o	o	o
24 Sulfur	o	o	o	0.7	o
25 Alcohols	o	o	o	o	o
26 Nitroaromatics	o	o	o	o	o
27 Fibers	o	o	o	o	o
28 Amides	o	o	o	o	o
29 Nitriles	o	o	o	o	o
30 Tars	1.8x10⁻⁴-0.12	1.2	o	o	o
31 Respirable particles	2.0x10⁻⁴	<0.0012	o	o	o
32 Arsenic	0.0025-8.15	Trace	o	o	o
33 Mercury	2.9x10⁻⁵-8.0017	<0.012	o	o	o
34 Nickel	2.9x10⁻⁴-8.0018	<0.035	o	o	o
35 Calcium					
36 Lead	o	o	NOT AVAILABLE	o	o
37 Other trace elements	o	o		o	o
38 Radioactive materials					
39 Other remaining materials					

(Continued)

3-32

TABLE 3-9. CONTINUED

Risk Analysis Units	Waste Stream Generation Rate, kg/hr			
	301 Demineralizer Regeneration Wastewater	307 Cooling Tower Blowdown	309 SCOT Sour Condensate	508 Upgrading Wastewater*
1 Carbon monoxide	0	0	0	0
2 Sulfur oxides	0	0	0	0
3 Nitrogen oxides	0	0	0	0
4 Acid gases	2.0×10^{-3}	0.042	0.87	0
5 Alkaline gases	0.42	0.12	0.029	0
6 Hydrocarbon gases	0	0	0	0
7 Formaldehyde	0	0	0	0
8 Volatile organochlorines	0	0	0	0
9 Volatile carboxylic acids	0	0	0	0
10 Volatile O&S heterocyclics	0	0	0	0
11 Volatile N-heterocyclics	0	0	0	0.0033
12 Benzene	0	0	0	0
13 Aliphatic/alicyclic	0	0	0	0.0067
14 Mono/Diaromatic hydrocarbons (excluding benzene)	0	0	0	0.0027
15 Polycyclic aromatic hydrocarbons	0	0	0	0
16 Aliphatic amines (excluding N-heterocyclics)	0	0	0	0
17 Aromatic amines (excluding N-heterocyclics)	0	0	0	0
18 Alkaline nitrogen heterocyclics ["azarenes"] (excluding "volatiles")	0	0	0	0
19 Neutral N, O, S heterocyclics (excluding "volatiles")	0	0	0	0
20 Carboxylic acids (excluding "volatiles")	0	0	0	0
21 Phenols	0	0	0	0.013
22 Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	0	0	0.013
23 Nonheterocyclic organo sulfur	0	0	0	0
24 Alcohols	0	0	0	0
25 Nitroaromatics	0	0	0	0
26 Esters	0	0	0	0.0014
27 Amides	0	0	0	0
28 Nitriles	0	0	0	0
29 Tars	0	0	0	0
30 Respirable particles	0	0	0	0
31 Arsenic	2.0×10^{-4}	0.000	0	0
32 Mercury	0.0011	0.0022	0	0
33 Nickel	0.062	0.056	0	0
34 Cadmium	4.9×10^{-5}	0.012	0	0
35 Lead	0.10	0.042	0	0
36 Other trace elements	— NOT AVAILABLE —			
37 Radioactive materials	0	0	0	0
38 Other remaining materials	0	0	0	0

* Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

TABLE 3-10. SOURCE TERM ESTIMATES FOR CONTROLLED AQUEOUS WASTE STREAMS

RCRA Analysis Units	301 Coal Storage Pile Runoff	436 Discharge to Surface Waters (Control Option 1)[a]	437 Discharge to Surface Impoundment (Control Option 2)[a]	301 Demineralizer Regeneration Wastewater	301 Cooling Tower Blowdown
		Waste Stream Generation Rate, kg/hr			
1 Carbon monoxide	0	0	0	0	0
2 Sulfur oxides	0	0	0	0	0
3 Nitrogen oxides	0	0	0	0	0.042
4 Acid gases	1.5×10⁻⁴	1.8–3.8	1.8–2.4	5.4×10⁻⁵	0.17
5 Alkaline gases	0.0026	18	18	0.11	0
6 Hydrocarbon gases	0	0	0	0	0
7 Formaldehyde	0	0	0	0	0
8 Volatile organochlorines	0	320	957	0	0
9 Volatile carboxylic acids	0			0	0
10 Volatile OAS heterocyclics	0			0	0
11 Volatile N-heterocyclics	0			0	0
12 Benzene	0	9.3×10⁻⁴	5.0×10⁻⁴	0	0
13 Aliphatic/alicyclic	0	<0.0059	<0.078	0	0
14 Mono/diaromatic hydrocarbons (excluding benzene)	0	3.4×10⁻⁴	0.0018	0	0
15 Polycyclic aromatic hydrocarbons	0	1.4×10⁻⁴	4.1×10⁻⁶	0	0
16 Aliphatic amines (excluding	0	0	0	0	0
17 Aromatic amines (excluding)	0	0	0	0	0
18 Alkaline nitrogen heterocyclics ("amines") (excluding "volatiles")	0	0	0	0	0
19 Neutral N, O, S hetero- cyclics (excluding "volatiles")	0	0	0	0	0
20 Carboxylic acids (excluding "volatiles")	0	6.9×10⁻⁴	0.0091	0	0
21 Phenols	0	4.5×10⁻⁸	0.0019	0	0
22 Aldehydes and ketones ("carbonyls")(excluding formaldehyde)	0	0	0	0	0
23 Nonaromatic organo	0	0.21	0.70	0	0
24 Sulfur	0	0	0	0	0
25 Alcohols	0	7.0×10⁻⁵	2.1×10⁻⁸	0	0
26 Nitrosamines	0	0	0	0	0
27 Esters	0	0	0	0	0
28 Amides	0	0	0	0	0
29 Nitriles	0	0	0	0	0
30 Tars	0	0	0	0	0
31 Respirable particles	1.8×10⁻⁶–0.18	<1.2	<1.2	5.4×10⁻⁵	0.0090
32 Arsenic	2.0–10⁻¹⁵	<0.0012	<0.0012	3.1×10⁻⁵	0.0022
33 Mercury	0.0026–0.15	Trace	Trace	0.012	0.056
34 Nickel	2.8×10⁻⁵–0.0017	<0.012	<0.012	1.3×10⁻⁵	0.012
35 Cadmium	2.9×10⁻⁴–0.0018	<0.035	<0.035	0.027	0.042
36 Lead	0.22	<200	<200	0.33	0.58
37 Other trace elements	0	0	0	0	0
38 Radioactive materials					
Other remaining material(s)					

[a] Small amounts of other organic compounds may be present in this stream, although supporting data are not available.

Uncontrolled emission rate estimates for cooling and dust removal blow-
down (Stream 210), compression and cooling condensate (Stream 211), and Rec-
tisol condensate/still bottoms (Stream 220) were based upon material balance
calculations and published test data (4,6,47). Uncontrolled emission rate
estimates for F-T wastewater (Stream 223) were based upon a published design
study (18). Uncontrolled emission rate estimates for upgrading wastewaters
(Stream 508) were based upon published refinery test data and design studies
(18,49). These wastewater streams would be combined for common treatment,
and two treatment alternatives were evaluated: 1) activated sludge followed
by filtration, granular activated carbon adsorption and discharge to surface
waters (Option 1); and 2) activated sludge followed, by cooling tower concentra-
tion and discharge to a surface impoundment (Option 2). The assumed perfor-
mance for the Option 1 control alternative included 95% removal of organics
(essentially no complex aromatic or heterocyclics are expected to be present
in these wastewaters), 10 ppmv residual dissolved alkaline gases, and 1-2
ppmv residual dissolved acid gases. The assumed performance for the Option 2
control alternative included 85% removal of organics with the same residual
levels of dissolved alkaline and acid gases as indicated for Option 1. It
was assumed that neither Option 1 nor Option 2 controls removed trace ele-
ments from the wastewater.

The quality of uncontrolled demineralizer regeneration wastewater
(Stream 301) and cooling tower blowdown (Stream 307) in the absence of cool-
ing tower concentration is largely dependent upon the quality of available
feed water. Although these streams are likely to contain low levels of trace
elements, emissions of trace elements in these streams are expected to be
small relative to emissions from other sources within the facility. Emis-
sion estimates for these streams are based upon average concentrations in
the electric utility industry (47).

The SCOT sour condensate (Stream 409) quality has been estimated based
upon information provided by the developer (27). Sour condensate is stripped
and reused within the facility as makeup water.

It should be noted that leachates from solid waste disposal may also
be generated. However, no landfill leachate data relating to the landfilled
waste streams are publicly available. The limited EPA EP leaching data for
quenched slag and dewatered dust are summarized in Section 3.3.4 (Table 3-11).

3.3.4 Source Term Estimates for Solid Waste Streams

A summary of uncontrolled solid waste streams and available characteri-
zation data is presented in Table 3-11. The dewatered K-T dust (Stream 209)
will be burned to recover heating value and reduce the waste volume. Spent
methanation, hydrogenation, hydrotreating, isomerization, reforming and SCOT
catalysts (Streams 238, 511, 512, 513, 514, and 410) are recycled to their
respective vendors for metal recovery or reprocessing and reuse. All other
solid waste streams are either landfilled directly or landfilled after chemi-
cal fixation or neutralization. very limited composition data and EPA EP
leaching data are available, and no landfill leachate data for the landfilled
waste streams are publicly available. Hence, source term estimates cannot
be prepared for either the uncontrolled or controlled solid waste streams.

3.4 DATA UNCERTAINTY AND LIMITATIONS

In the previous section source term estimates for most of the waste
streams generated by a K-T based F-T facility, particularly waste streams
unique to synfuels technologies were presented. However, available data on
the risk analysis units generally consists of single data sets which may not
include data for all RAUs present in the waste stream. Moreover, source
terms for waste streams from future commercial facilities could differ from
those presented in this report for several reasons. One reason for such
differences would be the uncertainty involved in estimating emission/effluent
compositions at this time; as discussed in Section 3.3, the environmental
data are limited, the foreign facilities tested are not entirely representa-
tive of proposed U.S. facilities, and there is necessarily some uncertainty
in making engineering estimates of trace components in discharges from com-
plex systems.

The major uncertainties and data limitations associated with source term
estimates for controlled gaseous and aqueous waste streams are summarized in
Tables 3-12 and 3-13. In the case of solid wastes, the composition of uncon-
trolled waste streams is of less significance than the composition of any
leachate resulting from landfilling these wastes. Hence, the major uncer-
tainty associated with solid waste streams relate to leachate characteristics
(Table 3-13).

TABLE 3-11. SUMMARY OF UNCONTROLLED SOLID WASTE STREAMS

Number	Stream Description	Average Generation Rate kg/hr	Composition Data/Leaching Characteristics
207	Quenched slag	38,000 (about 10% moisture)	Trace element leachability using EPA EP (mg/kg slag): Ag <0.2, As <8, Ba <0.2, Cd <0.1, Cr <0.8, Hg <0.004, Pb <1, Se <8 (11). Slag contains about 10% moisture which may be either clean rinse water or gas cooling/dust removal blowdown water.
209	Dewatered K-T dust	220,000 (about 50% moisture)	Trace element leachability using EPA EP (mg/kg dust @66% moisture): Ag <0.2, As=0.04, Ba <2, Cd=0.6, Cr=0.02, Hg <0.004, Pb=0.26, Se <0.02 (22). Dust moisture has some composition as gas cooling/dust removal blowdown.
212	Spent NO$_x$ catalyst	6.7 to 11	Cobalt-molybdate catalyst (17)
217	Spent shift catalyst	5.8 to 9.7	High temperature Fe-Cr catalysts contain about 44% Fe and 6% Cr. Low temperature Cu-Zn catalysts contain about 24% Ca and 36% Zn (38,39, 40,41).
221	Spent sulfur guard	33	Contains zinc oxide and zinc sulfide (42).
222	Spent F-T synthesis catalyst	2200	Iron-based catalyst – no published information regarding promoting elements.
238	Spent methanation catalyst	17	Nickel-based catalyst
300	Raw water treatment sludge	1200-1600	Contains 38% CaCO$_3$, 2% Mg(OH)$_2$ and 60% H$_2$O (43).

(Continued)

TABLE 3-11. CONTINUED

Stream Number	Stream Description	Average Generation Rate kg/hr	Composition Data/Leaching Characteristics
304	Boiler bottom ash	2100	Similar in composition to coal ash.
402	Spent Claus catalyst	4.2	Bauxite or alumina-based catalyst containing elemental sulfur, sulfides, sulfates.
410	Spent SCOT catalyst	1.2	Cobalt-molybdate catalyst
414	Spent bed media from FBC	74,000	Contains 8% $CaSO_4$, 6% CaO, 1%$CaCO_3$ and 85% ash (44).
415	Activated sludge solid waste	11,000	May contain refractory organics and trace metals.
423	Boiler fly ash	28,000	Similar in composition to coal ash.
442	FBC fly ash	6700	Similar in composition to coal ash.
424	FGD sludge from lime-stone scrubber	120,000	Contains 40% solids consisting of 48% $CaSO_3$, 16% $CaSO_4$ and 36% $CaCO_3$ (34).
509	Alkylation sludge	34	Sludge is expected to contain about 50% CaF_2 and may also contain alkylation tars.
510	Spent polymerization catalyst	2.1	Phosphoric acid on kieselguhr or quartz chips.
511	Spent hydrogenation catalyst	0.29	Cobalt-molybdate catalyst.
512	Spent hydrotreating catalyst	1.9	Cobalt-molybdate catalyst.
513	Spent isomerization catalyst	0.93	Platinum-based catalyst.
514	Spent reforming catalyst	1.4	Platinum-rhenium catalyst.

TABLE 3-12. GASEOUS WASTE STREAM DATA UNCERTAINTIES AND LIMITATIONS

Stream Number	Stream Description	Major Data Uncertainties and Limitations
200	Fugitive dust from material storage	● Emission factors are based upon test data from facilities with processing similar to that employed in synfuel applications. However, emission factors may vary greatly with local conditions.
202-205	Fugitive particulate from material conveying and processing	
		● Trace element emissions depend upon coal composition, trace element distribution among size fractions, and control efficiency for ach size fraction.
		● Data on the fraction of particulate which is respirable are limited.
206	Dust from thermal dryers	● Trace element emissions depend upon coal composition, trace element distribution among size fractions, and control efficiency for each size fraction.
429	Incinerated CO_2 offgas	● Emissions are based upon average data from similar applications. With proper incinerator operation, emissions are not expected to exceed estimates by more than a factor of two.
241	Fugitive organic emissions from process equipment	● Emission estimates are based upon petroleum refinery experience and equipment counts from conceptual F-T designs. Total mass emission rates may differ greatly in operating F-T facilities.
		● Emission composition estimates are based upon product slate estimates and limited data from F-T and petroleum products. Composition may differ greatly in operating F-T facilities.

(Continued)

TABLE 3-12. CONTINUED

Stream Number	Stream Description	Major Data Uncertainties and Limitations
302	Flue gas from power generation	● High degree of accuracy assumed since emission estimates are based upon a large, directly applicable data base and potentially applicable emission standards.
308	Evaporative emissions from alcohol storage	● Total emission estimates based upon correlations for petroleum liquids. Total emissions from F-T liquids may differ.
309	Evaporative emissions from gasoline storage	● Composition estimates are based upon limited data from F-T and petroleum products. Approach should be conservative in that emissions of heavy hydrocarbons are probably overestimated.
310	Evaporative emissions from diesel oil storage	Composition of emissions from F-T liquids may differ.
311	Evaporative emissions from fuel oil storage	
435	Treated FBC flue gas	● High degree of accuracy assumed since emission estimates are based upon a directly applicable data base and potentially applicable emission standards.
428	Incinerated SCOT tail gas	● Emission estimates for SO_x relate primarily to the volumetric flow of SCOT tail gas and the designed SCOT performance level. The volumetric flow of SCOT tail gas may increase by up to a factor of two, depending upon the degree of selectivity obtained in Rectisol. The SCOT unit could be designed to produce up to 500 ppmv H_2S in the tail gas rather than the 250 ppmv assumed. Thus, the worst-case increase in SO_x emissions would be a factor of approximately four.

(Continued)

TABLE 3-12. CONTINUED

Stream Number	Stream Description	Major Data Uncertainties and Limitations
428 (cont'd)		• Emission estimates for CO and NO_x relate primarily to the SCOT tail gas flow rate and may increase by a factor of approximately two, depending upon Rectisol selectivity.
219	CO_2 vent gas	• Emission rates are largely dependent upon details of the Rectisol design. Emission estimates are based upon performance data from the operation of units designed by Linde AG or its American subsidiary Lotepro Corporation. Different emission rates may be incorporated in designs provided by other licensors.
306	Cooling tower evaporation and drift	• Emission estimates are influenced by water quality estimates (see Table 3-13) and volatilization. No characterization data are available, although average cooling tower blowdown quality data from the electric utility industry have been incorporated into estimates.
502-507	Flue gas from process heaters	• Emissions are based upon published emission factors for gas-fired commercial heaters. Estimates are assumed to be accurate since process heaters are fired with sulfur-free light process gases. However, actual emissions will vary depending on heater operation.

TABLE 3-13. AQUEOUS WASTE STREAM DATA UNCERTAINTY AND LIMITATIONS

Stream Number	Stream Description	Major Data Uncertainties and Limitations
201	Coal storage pile runoff	● Quantity and quality of coal storage runoff are site- and coal-specific.
436	Discharge to surface waters (Option 1)	● Emission estimates depend primarily upon the combined wastewater generation rate and the control efficiency of wastewater treatment processes. The combined wastewater generation rate is not expected to vary by more than about 50%. However, estimated control efficiencies are based largely upon petroleum refining experience since data for the actual waste streams are not available.
437	Discharge to surface impoundment (Option 2)	
		● Concentration data or estimates for refractory organics which may be present at low levels are not available. Such data would be of particular interest for Option 2 controls since activated carbon adsorption is not employed.
	Leachate from solid waste disposal	● No landfill leachate data relating to the land-filled waste streams are publicly available.
		● Leachate generation rates are specific to the location and the design of the landfill.

Of the parameters influencing waste stream characteristics, variations in the feed coal composition are the most easily evaluated. Variations in the characteristics of bituminous coals are summarized in Table 3-14. These data provide a basis for evaluating ranges in certain waste stream characteristics. For example, the average sulfur level for bituminous coals is about 10% lower than the design coal sulfur concentration. Hence, on the average, FGD sludge production would be about 10% lower than the rate estimated on the design sulfur basis. However, on the average, flue gas sulfur emissions from the boiler would be unchanged due to the 260 ng/J SO_2 requirement specified by the NSPS for coals in this sulfur content range. Ash and slag production rates will vary in direct proportion to coal ash content. Similarly, trace element emissions in all coal derived gaseous and solid waste streams would vary in proportion to increases or decreases in their respective concentrations in the feed coal. It should be noted that such trace element extrapolations do not generally apply to liquid waste stream or leachate.

TABLE 3-14. VARIATIONS IN CHARACTERISTICS OF BITUMINOUS COAL

Coal Component	Eastern Bituminous Coals (34,48)			
	Design Coal (2,3)	Mean	Standard Deviation	Number of Data Points
Sulfur, % (dry basis)	3.13	2.8	0.75	Not Available
Ash, % (dry basis)	10.19	10.8	2.75	Not Available
Trace Elements, ppmv (dry basis)				
Ag	--	0.58	0.0	56
As	1	8.82	20	125
B	132·	56.5	13	125
Ba	--	148	91	104
Be	1.6	0.96	0.79	128
Cd	<0.4	0.66	0.08·	65
Cr	--	25.9	23	130
Cu	12	15.1	11.4	131
F	79	102	68.6	86
Hg	1.1	0.18	0.09	75
Ni	14	17.9	13.7	130
Pb	10	6.99	5.14	125
Se	1.3	2.60	0.99	68
V	20	33.5	45.1	127
Zn	43	37.8	17.2	131

3.5 REFERENCES

1. GKT Gesellschaft für Kohle-Technologie mbH. GKT's Coal Gasification Process Facts and Data.

2. Trials of American Coals in a Lurgi Gasifier at Westfield, Scotland. Woodall-Duckham, Ltd., Sussex, England. ERDA R&D Report No. 105, 1974.

3. Souther, N.F., et al. Potential Trace Element Emissions from the Gasification of Illinois Coal, Illinois Institute of Environmental Quality No. 75-08, February 1975.

4. Gesellschaft für Kohle-Technologie mbH. Large Scale Gasification Tests with U.S. Coal in Ptolemais, Greece, for Tennessee Valley Authority, USA. Essen, Federal Republic of Germany. Final Report, Vol. III, October 1981.

5. Firnhaber, B. and R. Wetzel. Status of Entrained Coal Gasification According to Koppers-Totzek and Shell-Koppers. The Institute of Chemical Engineers. Symposium Series No. 62, 1980.

6. Zee, C.A., J. Clausen and K.W. Crawford. Environmental Assessment: Source Test and Evaluation Report. Koppers-Totzek Process, EPA-600/7-81-009, January 1981.

7. FMC Corporation, Gasification of COED Chars in a Koppers-Totzek Gasifier, EPRI AF-615, July 1978.

8. The Dravo Corporation. Handbook of Gasifiers and Gas Treatment Systems. Report prepared for the United States Energy Research and Development Administration, FE-1772-11, February 1976.

9. Engelbrecht, A.D. and L.J. Partridge. Operating Experience with a 1000 ton/day Ammonia Plant at Modderfontein. Symposium on Ammonia from Coal, Tennessee Valley Authority, Muscle Shoals, Alabama, May 8-10, 1979.

10. Couch, A.T. and W.L.E. Davey. The Use of Fluidized Combustion to Burn the Fly Ash from Koppers-Totzek Gasifiers. The International Coal Conversion Conference, Pretoria, South Africa, August 16-20, 1982.

11. Hunter, C.A. and K.Y. Yu. Characterization of Solid Wastes from Indirect Liquefaction Facilities. Environmental Aspects of Fuel Conversion Technology - VI, A Symposium on Coal-Based Synfuels, Denver, Colorado, October 26-30, 1981.

12. Unpublished TRW non-proprietary data obtained during testing at the Nitrogenous Fertilizer Industry (NFI), Ptolemais, Greece.

13. Wetzel, R.E., K.W. Crawford, and W.C. Yee. Environmental Aspects of the GKT Coal Gasification Process. EPA Symposium on Environmental Aspects of Fuel Conversion Technology-IV, Denver, Colorado, October 26-30, 1981.

14. Ranke, G. Acid Gas Separation by Rectisol in SNG Processes. Linde AG, Munich, Germany, copy of presentation obtained through Lotepro Corporation, New York, N.Y.

15. Scholz, W.H. Rectisol: A Low-Temperature Scrubbing Process for Gas Purification. Advances in Cryogenic Engineering, Vol. 15, 1969.

16. Lotepro Corporation. Capabilities brochure by Lotepro Corporation.

17. Information provided to TRW by Linde AG, November 1982.

18. Schreiner, Max. Research Guidance Studies to Assess Gasoline from Coal by Methanol-to-Gasoline and Sasol-Type Fischer-Tropsch Technologies, Mobil Research and Development Corporation, FE-2447-13, August 1978.

19. Conceptual Design of a Coal-to-Methanol-to-Gasoline Commercial Plant. Volume I, Badger Plants Incorporated, Cambridge, Mass., FE-2416-43.

20. R.M. Parsons Co., Screening Evaluation for Synthetic Liquid Fuels Manufacture, EPRI AF-523, August 1977.

21. Billings, Roger E. Hydrogen from Coal Cost Estimation Guidebooks. NASA-CR-164692, 1981.

22. Tennessee Valley Authority, Office of Natural Resources. Wastewater and Solid Waste Characteristics, Process and Nonprocess Units. Prepared for Office of Coal Gasification, October 1982.

23. Coal Gasification Project, Draft Environmental Impact Statement. Tennessee Valley Authority, 1980.

24. Blackwood, T.R. and R.A. Wachter. Source Assessment: Coal Storage Piles, Monsanto Research Corporation, Dayton, Ohio, May 1978.

25. Jutze, G.A., et al. Technical Guidance for Control of Industrial Process Fugitive Emissions. PEDCo Environmental, Cincinnati, Ohio, March 1977, NTIS: PB 272-288.

26. PEDCo-Environmental, Inc., Assessment of Fugitive Particulate Emission Factors for Industrial Processes, Cincinnati, Ohio, EPA-450/3-78-107, September 1978. NTIS: PB 288-859.

27. Information provided to TRW by Shell Internationale Maatschappij, December 1982.

28. Sinor, J.W. Evaluation of Background Data Relating to New Source Performance Standards for Lurgi Gasification, Cameron Engineers Inc., Denver, Colorado, EPA 600/7-77-057, June 1977, 233 p.

29. Wetherold, R. and L. Provost. Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. EPA 600/2-79-044, February 1979.

30. Hoogendorn, J.C. Experience with Fischer-Tropsch Synthesis at SASOL, paper presented at Institute for Gas Technology, Chicago, Illinois, 1973, pp. 353-365.

31. Quinlivan, S., A. Panaloo, and M. Ghassemi. A Compendium of Physical and Chemical Characterization Data for Petroleum and Synthetic Fuel Products, Volume 1 - Petroleum and Shale Oil Products. Report prepared for the U.S. Environmental Protection Agency by the TRW Energy and Environmental Division. October 1982.

32. Control of Volatile Organic Compound Leaks from Petroleum Refinery Equipment, Guideline Series, Emission Standards and Engineering Division, U.S. EPA, EPA 450/2-78-036, June 1978.

33. U.S. EPA, Compilation of Air Pollution Emission Factors, Office of Air Quality Planning and Standards, Research Triangle Park, N.C., AP-42.

34. Shih, C.C., et al. Emissions Assessment of Conventional Stationary Combustion Systems; Volume III External Combustion Sources for Electricity Generation. Report prepared for the U.S. Environmental Protection Agency by the TRW Environmental Division, November 1980.

35. Jutze, G.A., et al. Technical Guidance for Control of Industrial Process Fugitive Emissions. PEDCo Environmental, Cincinnati, Ohio, Marcy 1977, NTIS: PB 272-288.

36. Cox, D.P., T.Y.J. Chu and R.J. Ruane. Characterization of Coal Pile Drainage, TVA, EPA-600/7-79-051, February 1979.

37. Information supplied by South African Coal, Oil, and Gas Corp. Ltd., to EPA's Industrial Environmental Research Laboratory, Research Triangle Park, November 1974.

38. Satterfield, C.N. Heterogeneous Catalysts in Practice, McGraw-Hill Book Co., New York, N.Y., 1980.

39. Catalyst Handbook, Imperial Chemical Industries, Ltd., Springer-Verlag, New York, N.Y., 1970.

40. Katalco 71-7 High Temperature Shift Catalyst Data Sheet, Katalco Corp., Oak Brook, Illinois, 1981.

41. Katalco 52 2 Low Temperature Shift Catalyst Data Sheet, Katalco Corp., Oak Brook, Illinois, 1976.

42. Allen, D.W. Final Sulfur Removal in Ammonia from Coal Plants, Symposium on Ammonia from Coal, Tennessee Valley Authority, Muscle Shoals, Alabama, May 8-10, 1979.

43. Permutit Company Inc. Water and Waste Treatment Data, 1961.

44. Young, C.W., et al. Technology Assessment Report for Industrial Boiler Applications: Fluidized Bed-Combustion, EPA 600/7-79-178e, November 1979.

45. Pacific Environmental Services. Compliance Analysis of Small Bulk Plants, report prepared under EPA Contract 68-01-3156, Task No. 17, October 1976.

46. Wachter, R.A. and T.R. Blackwood. Source Assessment: Water Pollutants from Coal Storage Areas. Monsanto Research Corp., Dayton, Ohio. EPA-600/2-78-004m, May 1978.

47. TRW Environmental Division. Aqueous Discharges from Steam Electric Power Plants: Data Evaluation. EPRI No. RP1851-1, October 1982.

48. Swanson, V.E., et al. Collection, Chemical Analyses, and Evaluation of Coal Samples in 1975. U.S. Geological Survey Open File Report OFR 76-468, 1976.

49. Development Document for Effluent Limitations Guidelines for the Petroleum Refining Point Source Category. U. S. Environmental Protection Agency. EPA 440/1-79/014b. December 1979.

INTERNAL DISTRIBUTION

1.	S. I. Auerbach	8. Central Research Library
2-6.	L. W. Barnthouse	9-23. ESD Library
3.	N. H. Cutshall	24-25. Labratory Records Dept.
4.	S. G. Hildebrand	26. Laboratory Records, RC
5.	D. K. Genung	27. ORNL Patent Office
6.	D. E. Reichle	28. ORNL Y-12 Technical Library
7.	S. Singh	

EXTERNAL DISTRIBUTION

29. Harold Bond, U.S. Environmental Protection Agency, MCRD-684,
401 M Street, SW, Washington, D.C. 20460
30. Office of Assistant Manager for Energy Research and
Development, Oak Ridge Operations, P. O. Box E, U.S. Department
of Energy, Oak Ridge, TN 37831
31-57. Technical Information Center, Oak Ridge, TN 37831

source term estimates are based largely upon published process conceptual designs and test data obtained from bench-scale, pilot or demonstration units. Moreover, due to the limited publicly available data relating to the performance of pollution controls applied to waste streams generated by synfuels processes, source term estimates for controlled waste streams reflect control efficiencies extrapolated from similar applications in other industries. Results of Task 1 are presented in three separate reports addressing direct coal liquefaction technologies, indirect liquefaction technologies and oil shale extraction technologies, respectively.

The potential exposure created by the transport, storage, and end use of synthetic fuel products is also one of major concern. To fully assess the risks associated with product utilization, Task 2 characterized the full range of products produced by each synthetic fuels process, the likely mode of transportation and the end uses of each product. Characterization data are quantified in terms of RAUs and are based largely upon published physical/chemical data on raw and hydrotreated coal liquids, raw and hydrotreated shale oil and coal- and shale-derived naphtha and other products. Results of Task 2 are presented in a separate report encompassing all eight selected synfuels processes.

This report presents the Task 1 results for indirect liquefaction technologies (i.e., Lurgi and K-T based F-T synfuels facilities). Base plant configurations evaluated in this report have been adapted from conceptual design information compiled for EPA's Pollution Control Technical Manuals (PCTMs) for the subject technologies; hence, process descriptions presented herein have been abstracted from these documents. Detailed references to the original data sources are provided in this document to support characterization data from the PCTMs and other publications.