SECTION 11

ENVIRONMENTAL FACTORS

This conceptual plant design has been responsive to requirements for control
of gaseous, liquid, and solid emissions from the plant units and ancillary
facilities. The means by which emission and noise level controls have been
accomplished are discussed in this section.

11.1 AIR POLLUTION ABATEMENT

The control of air contaminants released to the environment had a high
priority in plant and process design. Applicable standards covering the pro-
cess operations were used in design and engineering of the process and equip-
ment.

The major air pollution abatement effort is aimed at desulfurizing the
gases generated during the coal conversion process. The desulfurization pro-
cess extends to the gaseous fuels produced for inplant consumption so that
overall plant operations generate negligible sulfur emissions.

The units and processes utilized in the Oil/Gas plant conceptual design
to produce the desired fuels will be briefly reviewed here to highlight the
progressive removal from the streams of compounds or materials capable of
contributing to air pollution.

11.1.1 GENERATION AND CONTROL OF GASEOUS CONTAMINANTS

The air pollution abatement procedure is outlined in Figure 11-1,
which shows the nature and amount of all streams vented to the air; these
streams consist for the major part of inert gases (nitrogen and carbon diox-
ide). The effluent gases are shown vented separately to the air to identify
the contribution of specific process units. In reality, however, all streams,
with the exception of the particulates from the coal drying plant and the
effluents from the process boilers, are combined into a single stack before
venting to the air.

(1) Coal Preparation

Fugitive particulate emissions from coal sizing and
handling and from residual ash disposal and prevented
from becoming airborne by maintaining a wet condition
when not in a closed system.

The coal grinding and drying unit is the only source of
particulate emissions. A cyclone system removes the
coarse particles from the vent streams; a subsequent

baghouse system removes most of the fines, with final emissions to the air (0.023 g/cu ft) meeting both Federal standards for thermal dryer gases (0.031 g/cu ft) and state standards related to coal gasification plants (Table 11-2). The source of heat for drying process is steam generated inplant.

Ground, dry coal is fed to three reactors: the process gasifier, producing a syngas from which are derived both SNG and the hydrogen required for coal liquefaction; the dissolver, producing the liquid fuels; and the fuel gas gasifier, satisfying plant fuel requirements.

(2)   Process Gasifier

The process gasifier receives recycle char, steam, and oxygen in the lower slagging section and ground coal and steam in the upper section, and converts them to hydrogen, carbon monoxide, carbon dioxide, methane, hydrogen sulfide, and lesser amounts of ammonia, carbon oxysulfide, cyanides, and sulfur dioxide. At the elevated temperature, any oils or tars formed are expected to crack to gaseous products. The gas stream produced, containing entrained char, is cooled from 1,700 to 945°F through a series of heat exchangers that heat the incoming gases and produce steam. Then, the char is separated by a cyclone system and returned to the gasifier. The remaining fine particles that escaped the cyclone are removed by two dust filters capable of operating at high temperature and pressure.

The gaseous stream is then conveyed to a shift conversion unit where the stream is enriched in hydrogen by reaction of carbon monoxide with water. The metal catalyst employed operates in a sulfided condition reached by initial reaction with the hydrogen sulfide present; when the catalyst is regenerated (approximately every 6 months) by passage of steam and air, the sulfur present is oxidized to sulfur dioxide (66.4 ton per reactor, three reactors used), emitted through the main stack over a 24- to 48-hour period. Each of the three shift reactors operates at a progressively lower temperature; gas cooling is provided by water spray in quench pots. Final cooling of the gas down to 100°F occurs in a series of heat exchangers and condensate separators. The quench pot/condensate separator system acts as a water scrubbing system, removing practically all traces of particulates from the gas stream. The ammonia and part of the hydrogen sulfide and hydrogen cyanide present are also removed.

The next treatment step concerns the removal of acid
gases. A physical solvent process removes these gases
from the main stream and then, on selective regenera-
tion, releases a stream of hydrogen sulfide containing
part of the carbon dioxide, and a stream of nearly pure
carbon dioxide. The hydrogen sulfide stream is sent
to the sulfur recovery plant where it is oxidized to
elemental sulfur; any hydrogen cyanide present is
oxidized concurrently. The carbon dioxide stream, con-
taining some carbon monoxide (833 ppm) and hydrogen
sulfide (up to 10 ppm) is vented to the air through the
main plant stack, where overall concentrations of con-
taminants decrease on combination with other effluents.
The purified gas stream, consisting mainly of hydrogen,
but with sizable amounts of carbon monoxide and methane
present, is conveyed to the coal dissolver.

(3) Dissolver

The dissolver unit receives a preheated, pressurized
slurry of ground coal in coal-derived solvent and hydro-
gen and generates two product phases: a gas phase and
a slurry phase.

The gas phase is cooled and depressurized (recovering
heat and power) and then conveyed to an acid gas
removal unit, where hydrogen sulfide and carbon dioxide
are removed by absorption in an amine solution. The acid
gas stream obtained on regeneration of the amine is
led to the sulfur recovery plant. The purified gas stream
undergoes drying by molecular sieves and cryogenic
separation, with hydrogen returned to the dissolver and
hydrocarbon products fractionated to a methane-rich
stream, LPG, and naphtha. LPG and naphtha are treated
to reduce the sulfur level to 1 ppm or less, and the
methane-rich stream is upgraded to SNG. The SNG pro-
duced is essentially sulfur-free because a zinc oxide
guard reactor removes sulfur traces prior to methanation.

The liquid slurry phase consists of liquefied coal,
unreacted coal, and ash. After cooling by heat exchange
and depressurization by power recovery (hydraulic tur-
bines), the slurry is fractionated, with recovery of
process solvent for return to the dissolver, and then
filtered to separate solid materials from liquid hydro-
carbons. The solids (filter cake) are fed to the fuel
gas gasifier. The liquids (fuel oil) represent the
largest single product stream in the plant. This fuel
stream contains 0.4% sulfur and 1 to 1.5% nitrogen.
The amount of sulfur is environmentally acceptable; the
amount of nitrogen present, however, may lead to

increased production of nitrogen oxide on combustion
with respect to crude-oil derived fuels.

(4) Fuel Gas Gasifier

The fuel gas gasifier receives char, filter cake, air,
and steam in the lower (slagging) section and coal and
some additional air in the upper section, and produces
primarily synthesis gas (carbon monoxide and hydrogen),
plus nitrogen, carbon dioxide, hydrogen sulfide, and
lesser amounts of ammonia, carbon oxysulfide, cyanides,
and sulfur dioxide. At the elevated reactor tempera-
ture, any oils or tars formed are expected to crack to
gaseous products. The gas stream produced, leaving the
gasifier at 1,800°F, is separated from most of the
entrained char in a cyclone system, with the char
returned to the gasifier after using its heat content
for filter cake drying. The gas is then cooled to
100°F through a series of heat exchangers that heat the
gasifier input gases and produce steam; the condensate
formed contains all of the ammonia and part of the
sulfides and cyanides and is treated as described below.
The cooled gas stream passes through an electrostatic
precipitator where most of the fine particulates sus-
pended are removed and then is conveyed to a sulfur
removal unit where a redox solution converts all but 1
ppm of the hydrogen sulfide and sulfur dioxide present
to elemental sulfur. At the same time, practically
quantitative removal of any remaining particulates is
achieved.

The cleaned low-Btu (145 Btu/cu ft) fuel gas is used to
satisfy inplant energy requirements. Four-fifths (4/5)
of this gas is used for steam generation and one-fifth
(1/5) for process heaters. On combustion a negligible
amount of SO_2 (141 lb/day) is generated by oxidation of
the trace of hydrogen sulfide present. The amount of
nitrogen oxides generated is also moderate, due to the
flame-cooling effect of the large amount of inert gases
(carbon dioxide and nitrogen) present. Combustion
experiments with low-Btu gas show that a maximum NO_x
concentration in the effluent gases of 50 ppm (as NO_2)
can be expected.[10]

(5) Sulfur Recovery Plant

The sulfur recovery plant receives three hydrogen sul-
fide streams originating from the acid gas removal unit
on the process gasifier train, from a similar unit on
the dissolver train, and from the sour water stripping
unit; 95% of the sulfur present is oxidized to high-
purity elemental sulfur, with the remaining 5% con-
verted in a subsequent unit, the tail gas unit. The

tail gas treatment involves reduction of all sulfur
species to hydrogen sulfide, absorption by a redox so-
lution, and oxidation to give high purity sulfur. The
final vent gas contains carbon dioxide, plus traces of
carbon oxysulfide (80 ppm), hydrogen sulfide (1 ppm),
and carbon monoxide (412 ppm). The carbon monoxide and
carbon oxysulfide concentrations decrease on mixing
with the other vent gases (see below).

(6) Formation of Metal Carbonyls

Metal carbonyls are gaseous or highly volatile compounds
that can form when finely divided metals, such as cata-
lyst or reduced ash particles, are in contact with
carbon monoxide at moderate temperatures (50-750°F).[4]
Most transition metal carbonyls are highly toxic; how-
ever, they decompose at high temperatures or at low
partial pressures of carbon monoxide, such as in the
atmosphere.

A consideration of the sites in the Oil/Gas plant where
metal carbonyls could possibly form has identified
three main locations: the process gasifier (and shift
converter that immediately follows), the dissolver, and
the fuel gas gasifier. Carbonyls are unlikely to form
at the elevated temperatures prevailing in the process
gasifier and the shift converter unit; furthermore, the
hot gas cleanup system removes ash particles before the
gas is cooled, thereby precluding the contact of
metallic particles with carbon monoxide at lower tem-
peratures. Elevated temperatures also prevail in the
dissolver unit, and the carbon monoxide concentration
is low (3% molar). Conditions are therefore unfavor-
able to the formation of metal carbonyls. In the fuel
gas gasifier train, gases are cooled in the presence of
coal ash, and iron carbonyls could possibly form. These
carbonyls, however, will be thermally decomposed on
combustion of the fuel gas in plant burners; any amounts
conveyed to the sulfur recovery plant would also be
thermally oxidized in that unit.

As mentioned previously, metal carbonyls decompose rapidly
in the air. Representative half-lives where calculated and
found to range from minutes for nickel carbonyls to hours
for iron carbonyls. These compounds represent, therefore,
a possible hazard to plant personnel rather than to the
outside environment. Hazardous conditions would defi-
nitely be present during startup and shutdown operations,
when metal carbonyls could form in significant concentra-
tions. Operating procedures in these circumstances in-
clude flaring of vent streams and protective equipment
(oxygen respirators and protective clothing) for personnel
opening or entering affected reaction vessels.

(7)   Stack Arrangement

Air effluents are emitted into the atmosphere from four
outlets: the coal drying plant (particulates), the two
process heaters (one-fifth of fuel combustion gases),
and the main plant stack (all other effluents combined).
The composition of the effluents emitted to the air from
the outlets specified is detailed in Table 11-1.

11.1.2   COMPLIANCE WITH SOURCE EMISSION STANDARDS

Source emission standards for coal conversion plants have not
been issued by the Federal Government. Of the states, only New Mexico has
issued specific regulations covering coal gasification plants; these regu-
lations can be considered for illustrative purposes only. The State of
Illinois, a likely candidate for a plant site, has issued standards for petro-
chemical processes which can be considered to be related to the Oil/Gas plant
operation. The standards are as strict or stricter than the Federal Standards
for petroleum refining.

For illustrative purposes, the Illinois and the New Mexico source
emission standards are compared with the emissions from the conceptual design
in Table 11-2. As shown in the table, all estimated emissions are lower than
the ones mentioned in the standards.

11.1.3   CARBON DIOXIDE EMISSIONS

It is estimated that significant carbon dioxide emissions (on
the order of 34,000 TPD; see Table 11-1) would be generated. Possible effects
of these emissions were investigated. Carbon dioxide is not toxic, and the
natural background concentration in the atmosphere is approximately 300 to
500 ppm.

Global weather modification effects have been attributed to
increased carbon dioxide generation by fossil-fuel combustion. A gradual
warming trend has been predicted, on the order of $0.5°C$ in 25 years. However,
actual temperature trends have shown a cooling of $0.3°C$ from 1945 to the
present.

On a localized scale, no micrometeorological effects due to in-
creased carbon dioxide have been reported. Emissions from the Oil/Gas facil-
ity could approximately double the average atmospheric carbon dioxide concen-
trations to 600 to 1,000 ppm in the vicinity of the plant. The lowest concen-
tration at which some physiological effects (dyspnea and headache) have been
observed is 30,000 ppm; therefore, no effects are expected at the levels men-
tioned. Moreover, vegetable life has been reported to benefit from increased
atmospheric concentrations of carbon dioxide.

11.2   SULFUR BALANCE

The sulfur balance for the conceptual design of a commercial Oil/Gas
plant is detailed in Table 11-3. A total of 95% of the coal sulfur content

is recovered as elemental sulfur, with most of the remainder present in the fuel oil product. The amount absorbed by the catalyst beds (mainly in the shift reactors) would be emitted every 6 months as sulfur dioxide on regeneration of the catalyst. At the temperature conditions prevailing in the design gasifiers, it was concluded that negligible amounts of sulfur would remain with the ash.

11.3 AQUEOUS EFFLUENTS

The geographic area where the Oil/Gas plant, as conceived, would be located is the U.S. Eastern Interior (coal) Region, where an abundant supply of water is available. Most likely, one of the major rivers in this area would provide the water supply for the plant.

Based on adequate availability of water, the wastewater treatment is a combination of recycling and discharge of aqueous effluents. The most heavily contaminated streams undergo steam distillation; the organic contaminants separated are fed with steam to the process gasifier to achieve their thermal destruction. Medium contaminated streams are purified physically and biologically and are then reused for slag quenching. The lightly polluted streams are treated to make them acceptable to the environment and are then discharged to the river.

11.3.1 GENERATION AND TREATMENT OF AQUEOUS CONTAMINANTS

The generation and treatment of aqueous contaminants is outlined in Figure 11-2. 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. The progressive treatment and disposition of the streams is also shown and approximate flow values for streams withdrawn and returned to the river are reported.

The water supply provides approximately 18,000 gpm of raw water, which after purification by flocculation and settling, is used for cooling water makeup and after further sand filtration and deionization, is used for boiler feedwater makeup. Potable water will be supplied by wells. The water supply from the river is not used for coal sizing and cleaning (a captive system feeding on a mine-based pond is used for this unit) or for coal grinding and drying where no wet systems are employed.

The most highly contaminated stream is the combined sour water generated as aqueous condensates by the process gasifier, the fuel gas gasifier, and the coal dissolver. Major contaminants present are hydrogen sulfide, ammonium sulfide, phenols, cresols, xylenols, and thiocyanates; cyanides and solids (ash and char particles) may also be present. The gaseous contaminants (hydrogen sulfide and ammonia) are removed by steam stripping. Ammonia is separated in a proprietary process unit, regenerated by heating, and purified to anhydrous ammonia. Hydrogen sulfide is conveyed to the sulfur plant for conversion to elemental sulfur. Under the acidic conditions of the sour water, most cyanides present would be volatile (as hydrogen cyanide) and therefore would be stripped with the hydrogen sulfide and conveyed to the sulfur plant, where they would be destroyed by thermal oxidation. The stripped

aqueous stream is conveyed to a high-temperature steam drum in the process gasifier unit, where the organic contaminants volatilize and are fed with the steam to the gasifier to undergo thermal oxidation. The blowdown from the steam drum is vaporized on cooling the product gas prior to shift conversion; any solids present are removed by filters on the condensate return lines.

Oily water streams produced during plant operation or collected as contaminated runoff from process areas are conveyed to a gravity separator. The water phase is further purified in an oily water pond, with the effluent used for slag quench. The combined oil fractions are led to a separator with the oil phase returned to the fractionation unit for product recovery. The aqueous phase is combined with the effluents from the slag settling basin and the sewage treatment plant and is treated in a bio-oxidation pond, which also provides firewater. The effluent from the biopond is also used for slag quench.

The cooling tower blowdown stream is the largest in volume and is only lightly contaminated by corrosion inhibitors (zinc salts and inorganic phosphates). This stream is combined with deionizer wastes, containing mainly inorganic salts, and with boiler blowdown, also lightly contaminated by corrosion inhibitors. After neutralization, the stream is treated with lime in a settler/clarifier. The lime sludge, containing most of the zinc and phosphates, is disposed of in a landfill, and the treated stream is returned to the river, together with any runoff collected from clean areas. If required by specific site conditions, a final polishing pond may be added for removal of suspended solids from the runoff collected.

11.3.2 COMPLIANCE WITH 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 could be considered related to an Oil/Gas process are the Federal standards issued for petroleum refining. Average attainable concentrations that were the base for such standards are reported in Table 11-4, together with the corresponding values for the aqueous effluents estimated for the Oil/Gas plant. As shown in the table, these values are either the same or lower than the Federal parameters.

The State of Illinois has issued aqueous effluent standards applicable to all sources discharging to the natural waters of the state. These standards are reported in Table 11-5 and for illustrative purposes were compared with the Oil/Gas effluents. All Oil/Gas plant effluents are estimated to either meet or be lower than such standards.

11.4 SOLID WASTES

The Oil/Gas plant generates two main types of solid waste materials: ash from the coal gasifier and sludge from various wastewater treatment units. Both materials are disposed of using environmentally acceptable procedures.

The mining and coal cleaning and sizing operations generate sizable amounts of solid wastes which are disposed of at the mine site.

11.4.1 ASH

The two gasifiers included in the Oil/Gas plant design receive coal in the upper section and convert it to gaseous products and entrained char. The largest part of the char is separated from the gas stream by physical means (cyclones) and returned to the lower section of the gasifiers after utilization of its heat content. There, on reaction with oxygen, the char generates hot gases and ash, which melts to slag. The slag is withdrawn from the bottom of the gasifiers; on quenching with water, it fragments into sand granules. Gases generated on quenching are returned to the gasifier. The slag slurry is conveyed to a settling basin where the solids separate; they are then collected and transported to the mine for burial with the mine spoils. If outlets exist nearby, this material could also be utilized as filler in aggregates for construction blocks or road building.

The fine particles that escape the cyclones are removed downstream by more efficient devices (dust filters for the process gasifier and an electrostatic precipitator for the fuel gas gasifier). This material, because of its small size, consists mainly of ash particles and is similar to power plant fly ash; some char, however, may also be present. According to the present design, the material will be dispersed with the mine spoils and buried at the mine site. The amounts of slag and fly ash generated by the two gasifiers are:

Gasifier	Slag	Fly Ash
Process	1,200	25
Fuel gas	3,000	310

The possibility exists of leaching trace metals from the ash into ground or surface waters. The difference in physical properties between slag and fly ash would suggest a different leaching behavior; slagged ash exhibits a glass matrix that would possibly inhibit leaching. Experimental studies have been carried out on the leaching of power plant fly ash or unslagged bottom ash; according to the results of a recent study[8], selenium, chromium, and boron (and occasionally mercury and barium), were released on simulated leaching, and the concentrations reached exceeded the values recommended by EPA for public water supplies. To our knowledge, no leaching tests of slagged ash have been carried out; experiments using the slag generated by a slagging gasifier, such as the Bi-Gas pilot plant or a Koppers-Totzek unit, would be very useful.

11.4.2 SLUDGES

Various water treatment units generate sludges (see Figure 11-2) of organic and inorganic origin. The settler/clarifier treating raw river water generates an inoffensive sludge that is returned to the mine. The sludges generated on treatment of wastewater, however, contain contaminants that could possibly pollute groundwater if buried with the mine spoils; for example, the sludge generated on treatment with lime of cooling tower blowdown contains sizable amounts of zinc. These sludges, therefore, are disposed of in a landfill.

11.4.3 MINE WASTES

The surface mining operation proceeds in an orderly fashion, following an environmentally sound mining plan. The topsoil is removed and stored, and the overburden is then stripped and used to refill the previous pit, in combination with the inorganic wastes from the coal cleaning and sizing plant (rocks, clay, and mud) and the vitrified ash from the gasifiers. The mined-out area is restored to approximately the original surface contour, and then the topsoil is replaced, fertilized, and reseeded, completing the land reclamation cycle.

The coal cleaning and sizing plant is located in proximity of the mine. This arrangement minimizes the exposure to the air of mine spoils, with consequent negligible oxidation of coal pyrites to oxygenated sulfur acids.

11.5 NOISE

Noise control will be an integral part of the layout and design of the Oil/Gas commercial plant. The Occupational Safety and Health Act of 1970 regulates the amount of weighted noise a worker may be exposed to in order to prevent ear damage. Local codes usually regulate the level of noise that an industrial plant is permitted to generate at the property line above the normal ambient background level. The applicable regulations and codes will be used as the design basis for noise control in plant design and layout.

Special attention will be given to the coal gasifier and oxygen plant fans, compressors, and pressure letdown valves. The sound exposure standards will be met by a combination of noise-reduction engineering techniques, such as the sound-proofing of turbines, silencing of valves, and use of sound and vibration absorption materials. Process units not requiring close observation and capable of high noise levels, such as oxygen compressors, will be barricaded.

11.6 TRACE ELEMENTS

Due to its organic origin and its intimate commixture with crystal formations, coal contains a large number of elements in minor or trace quantities. Actually, out of 92 known nontransuranic elements, only 16 (Ar, Ac, At, Fr, He, Ir, Kr, Ne, Os, Pa, Pm, Re, Ru, Tc, Tm, and Xe) have not yet been found in coal.

For illustrative purposes average amounts of trace and other elements for 82 coals from the Illinois basin are shown in Table 11-6. When the coal is cleaned using flotation procedures (as in the Oil/Gas process), it becomes enriched in elements having higher affinity for the organic phase; a rating of elements according to their affinity for the organic or inorganic phase for an Illinois No. 6 coal is shown in Table 11-7.

A number of studies have analyzed the behavior of trace elements in coal-fired power plants.[9,11] In general, the elements have been divided into two groups, the ones appearing mainly in the bottom ash (elements or oxides having lower volatility) and the ones appearing mainly in the fly ash (elements or oxides having high volatility). For power plants using dry particulate collection devices (e.g., electrostatic precipitators), it was believed

that the most volatile elements, such as mercury and selenium, could actually
escape at the elemental state with the flue gas. Wet scrubbers, however, were
believed capable of removing most of the elements from the gas streams and
transferring them to the liquid effluent.

In the Oil/Gas plant, no particulates from coal combustion escape into
the atmosphere; all particulate streams are collected quantitatively and either
returned to the lower section of the gasifiers, where they melt and are
removed as slag, or removed as fly ash and disposed of as mentioned in sub-
section 11-4. Any eventual dispersion of the elements present depends on the
possibility of leaching, discussed in the section quoted. The only concern,
therefore, is to identify elements that may be occurring in the gaseous state.
The reducing atmosphere present in the middle and top part of the gasifier may
also favor different chemical combinations absent in the oxidizing atmosphere
of a power plant.

Among the trace elements present in coal with recognized toxic proper-
ties, the high volatility elements beryllium, mercury, and lead do not form
gaseous hydrides, will condense on cooling, and very likely will be almost
completely removed by the aqueous condensates formed on gas cooling and/or
purification. Arsenic, antimony, and selenium have lower volatility but can
form gaseous (covalent) hydrides, namely arsine, stibine, and hydrogen sele-
nide. These compounds, however, have stability characteristics that preclude
their formation at the temperature and pressure prevailing in the Oil/Gas
plant gasifiers. From general chemical principles, it would appear, there-
fore, that harmful trace elements are not released to the atmosphere. Exper-
imental confirmation, however, is desirable and should be obtained from
specific pilot plant studies.

11.7   INCREMENTAL COST OF POLLUTION ABATEMENT

Ten units in the Oil/Gas plant contributed to the facility capability
to meet environmental requirements. These units are highlighted with heavy
frames in Figure 11-3. The environmental concern addressed by the unit, the
equipment required, and capital and operating costs are shown in Table 11-10.

The total capital cost for environmental pollution abatement, approxi-
mately $152.5 million, corresponds to 12.5% of the total capital cost for the
plant ($1,225 million). The total operating costs for pollution abatement,
(approximately $14.7 million, correspond to 7.6% of the total operating costs)
for the plant ($192.9 million). These costs represent a sizable fraction of
the total investment. They are comparable to percentage costs quoted by the
EPA[1,6] for pollution abatement in large-size oil refineries; for these facil-
ities, both capital and operating costs were estimated to range between 6 and
12% of the total costs of the plants.

11.8   OCCUPATIONAL SAFETY

Occupational Health and Safety Administration (OSHA) and Mining Enforce-
ment and Safety Administration (MESA) standards concerning the health and
safety of the workers who would be running the Oil/Gas plant will be strictly
adhered to.

Of particular interest in coal conversion projects is the possible formation of carcinogenic compounds during hydrogenation and pyrolysis of coal. These compounds are usually found in coal tars and coal-derived oils with boiling points higher than 480°F; they consist mainly of polycyclic aromatic hydrocarbons and amines, which are lipid soluble and can enter cells easily. The carcinogenic activity is believed to be attributable to their molecular shape, which permits them to fit into the structure of DNA and cause self-reproducing mutations.

Statistically significant increases in the incidence of skin and lung cancer were observed, especially for coke oven workers who are exposed to contact and inhalation of coal tar products. These findings led the Federal Government to issue an OSHA Standard of 0.2 mg/m³ (8-hour average) for coal tar pitch volatiles (anthracene, benzo(a)pyrene, phenanthrene, acridine, chrysene, and pyrene).

For both humans and laboratory animals, occasional exposure to the carcinogens is not sufficient for cancer development. Rats developed tumors after the chemical agents were applied 2 to 3 times per week to the shaved skin for approximately 1 year. The shortest exposure time recorded for the development of skin cancer in workers handling coal hydrogenation products was nine months.[22] The Federal standard mentioned represents the consensus of governmental and industrial hygienists on a threshold limit value that would minimize exposure risks.

Oils and tars are not expected to be formed under the operating conditions of the entrained gasifiers used in the Oil/Gas plant. The entire dissolver train, however, handles coal-derived oils and will therefore require strict application of industrial hygiene practices.
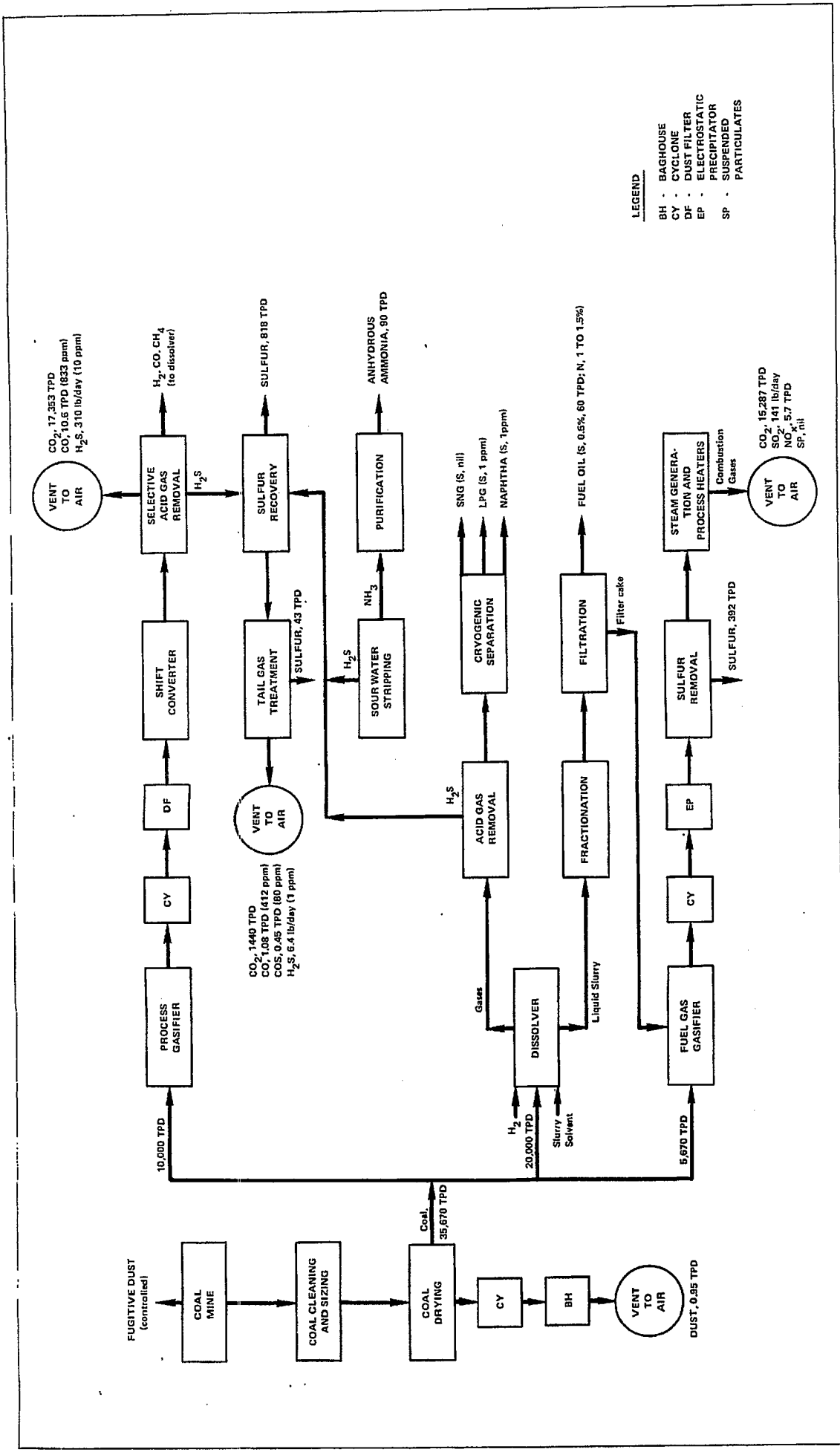
11.9 FUEL REGISTRATION REGULATIONS

Under authority of the Clean Air Act, the EPA has issued regulations concerning the registration of commercial fuels;[7] one of the requirements is testing for potential public health effects, including carcinogenic effects. Carcinogenic activity for laboratory animals has been observed for the higher boiling fuel oils obtained from petroleum refining;[2] these products have obtained registration. It is therefore expected that coal-derived fuel oils will also be candidates for registration. Biological tests of these compounds are being programmed.

The regulations also cover air emissions generated on combustion of fuels. As mentioned above, the synthetic fuel oil produced may contain 1 to 1.5% nitrogen, an amount comparable to the original nitrogen content of the coal; the amount of nitrogen oxides produced on combustion is therefore expected to be higher than for corresponding petroleum derived fuels. However, oil combustion lends itself to a number of nitrogen oxide abatement procedures, such as low excess air firing, staged combustion, and flue gas recirculation. These procedures are expected to reduce nitrogen oxide emissions to values that meet the present Federal standard (0.3 lb of nitrogen dioxide per million Btu of fuel heat content).

11.10 SOCIOECONOMIC IMPACT

The Oil/Gas facility and the associated coal mine are expected to require a total force of approximately 2,350 people. Assuming, using average economic data, that each direct worker generates two induced jobs and that each income producer supports a family of 2.5 people, a total of 17,000 people would be associated with the operation of this coal mining and synthetic fuel facility.

The project is therefore bound to cause modifications of the social and economic structures in the site area and could seriously tax the infrastructure services of an established community. A list of some of the services required includes housing, transportation, educational facilities, meeting and shopping conveniences, recreational facilities, houses of worship, medical facilities, and security. The positive economic aspects of the project could be welcomed in economically depressed areas; they could also be feared in well-established communities where the inhabitants would rather forego the additional income generated than face dislocations of people, homes, social customs, or living patterns. Foremost for a successful establishment of the new community is the amount of preliminary planning dedicated. Accurate investigations of community feelings will reveal if new developments and local growth are desired or if it were preferable to plan a new city for the plant workers. The short term impacts of the influx of construction workers will also have to be considered. Here too, preliminary planning will ensure a smooth transition from temporary to permanent facilities and a minimum disruption of the local economy.

Figure 11-1 - Block Flow Diagram, Air Pollution Abatement, Oil/Gas Plant (See text for stack arrangement)

LEGEND

BH - BAGHOUSE
CY - CYCLONE
DF - DUST FILTER
EP - ELECTROSTATIC PRECIPITATOR
SP - SUSPENDED PARTICULATES

11-15

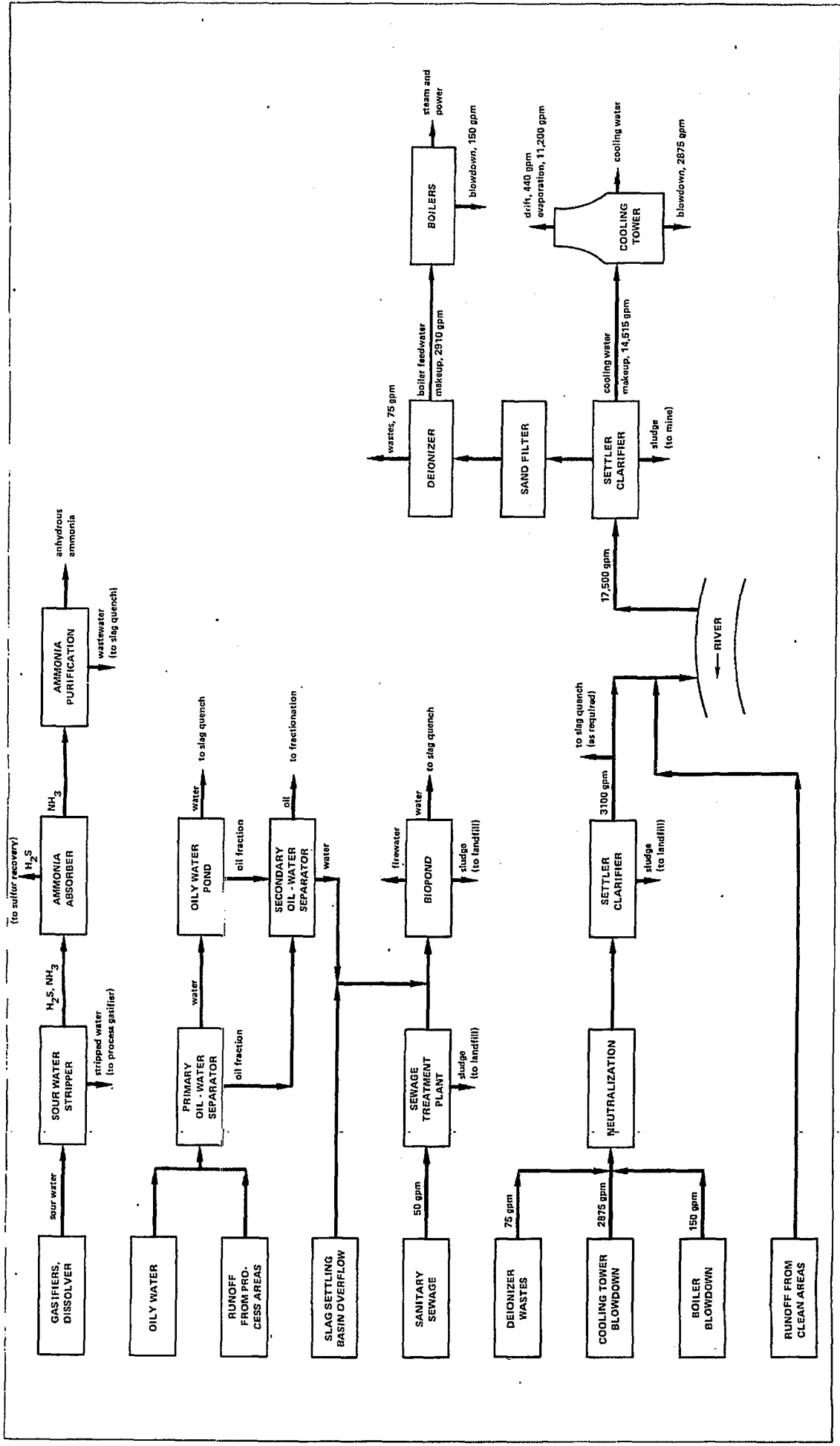Page Intentionally Left Blank

Figure 11-2 - Block Flow Diagram,
Water Treatment and Supply,
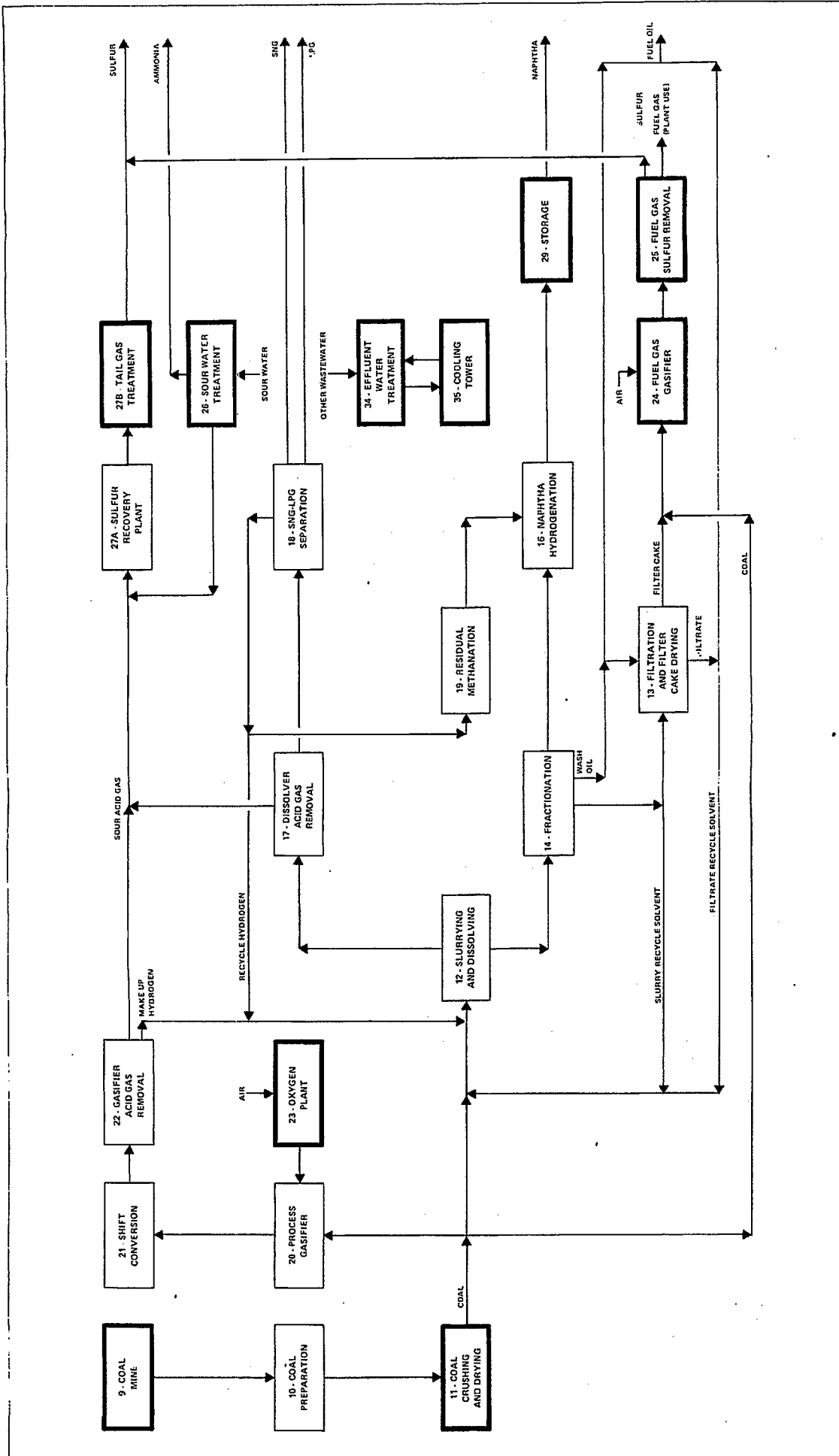Oil/Gas Plant

11-17

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Figure 11-3 - Block Flow Diagram, Highlighting Units
Requiring Environmental Pollution Abatement
(Heavy Frames), Oil/Gas Plant

11-19

Table 11-1 - Effluents Emitted to the Air

Outlet	Gaseous Effluent	Amount	Concentration
Main stack	Carbon dioxide	31,024 TPD	-
	Carbon monoxide	11.7 TPD	166 ppm
	Carbon oxysulfide	0.5 TPD	3 ppm
	Hydrogen sulfide	316 lb/day	2 ppm
	Sulfur dioxide	113 lb/day	0.3 ppm
	Nitrogen oxides	4.5 TPD	39 ppm
Process heater 1	Carbon dioxide	1,528 TPD	-
	Sulfur dioxide	14 lb/day	0.4 ppm
	Nitrogen oxides	0.6 TPD	50 ppm
Process heater 2	Carbon dioxide	1,528 TPD	-
	Sulfur dioxide	14 lb/day	0.4 ppm
	Nitrogen oxides	0.6 TPD	50 ppm
Coal drying plant	Particulates	0.95 TPD	-

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Table 11-2 - Comparison of Gaseous Emissions with Illinois and New Mexico Source Emission Standards

Pollutant	Illinois Standards, Petrochemical Plant	New Mexico Standards, Coal Gasification Plant	Gaseous Effluents, Oil/Gas Plant
Particulate matter	81 lb/hr	0.05 g/ft³	79 lb/hr,[a] 0.035 g/ft³
Sulfur dioxide	1.2 lb/MM Btu	-	1 ppm[b]
Carbon monoxide	200 ppm, 50% excess air	-	14⁻ ppm[c]
Nitrogen oxides	0.2 lb/MM Btu[d]	-	0.1 lb/MM Btu
Organics (methane excluded)	100 ppm (CH₄ equivalent)	-	Nil
Total reduced sulfur (H₂S + COS + CS₂)		100 ppm	5 ppm
Hydrogen sulfide		10 ppm	2 ppm
Hydrogen cyanide		10 ppm	Nil
Hydrogen chloride/ hydrochloric acid		5 ppm	Nil
Ammonia		25 ppm	Nil
Gas burning process boilers, particulate matter		0.03 lb/MM Btu, LHV	Nil
Gas burning process boilers, sulfur dioxide		0.16 lb/MM Btu, LHV	0.001 lb/MM Btu
Total sulfur		0.008 lb/MM Btu of feed (coal) heat input, HHV	0.002 lb/MM Btu[e]

[a] From coal drying plant.

[b] 66.4 tons of sulfur dioxide emitted twice a year, over 24 to 48 hours, on regeneration of the catalyst of each shift reactor (three reactors-total). The sulfur dioxide generated on combustion of the plant fuel gas amounts to ?b HV. If these combined amounts were averaged out over the year, they would correspond to 0.003 lb/MM Btu/day.

[c] Value obtained on application of the 50% excess air correction to the effluent from the steam generating unit.

[d] Applies to firing of gaseous fossil fuel.

[e] Includes the sulfur dioxide emitted occasionally on regeneration of the shift reactor catalyst ...

Table 11-3 - Sulfur Balance (TPD)

Total Input from the Typical Feed Coal	1,312.7
Outputs: As elemental sulfur	1,252.3
In the fuel oil	59.9
As carbon oxysulfide emissions	0.2
Adsorbed on catalyst beds	0.3
Total	1,312.7

Table 11-4 - Comparison of Aqueous Effluents with
Federal Petroleum Refinery Standards[a]

Parameter	Federal Standards, Petroleum Refinery	Aqueous Effluents, Oil/Gas Plant (mg/ℓ)
BOD 5	15	10
COD	100	100
Total organic carbon	33	33
Suspended solids	10	10
Oil and grease	5	5
Phenol	0.1	Nil
Ammonia-N	80% removal	Nil
Sulfide	0.1	Nil
Cr, tertiary	0.25	Nil
Cr, hexavalent	0.005	Nil

[a]Average attainable concentrations from the application of best
practicable control technology currently available.[3]

Table 11-5 - 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 to 10
Phenols	0.3
Selenium (total)	1.0
Silver	0.1
Zinc (total)	1.0
Total suspended solids	12.0

Table 11-6 - Mean Analytical Values for 82 Coals from the Illinois Basin[5]

Constituent	Mean	Constituent	Mean
As	14.91 ppm	Cl	0.15%
B	113.79 ppm	Fe	2.06%
Be	1.72 ppm	K	0.16%
Br	15.27 ppm	Mg	0.05%
Cd	2.89 ppm	Na	0.05%
Co	9.15 ppm	Si	2.39%
Cr	14.10 ppm	Ti	0.06%
Cu	14.09 ppm	ORS	1.54%
F	59.30 ppm	PYS	1.88%
Ga	3.04 ppm	SUS	0.09%
Ge	7.51 ppm	TOS	3.51%
Hg	0.21 ppm	SXRF	3.19%
Mn	53.16 ppm	ADL	7.70%
Mo	7.96 ppm	MOIS	10.02%
Ni	22.35 ppm	.VOL	39.80%
P	62.77 ppm	FIXC	48.98%
Pb	39.83 ppm	ASH	11.28%
Sb	1.35 ppm	Btu/lb	12,748.91
Se	1.99 ppm	C	70.69%
Sn	4.56 ppm	H	4.98%
V	33.13 ppm	N	1.35%
Zn	313.04 ppm	O	8.19%
Zr	72.10 ppm	HTA	11.18%
Al	1.22%	LTA	15.22%
Ca	0.74%	—	—

Note: Abbreviations other than standard chemical symbols: organic sulfur (ORS), pyritic sulfur (PYS), sulfate sulfur (SUS), total sulfur (TOS), sulfur by X-ray fluorescence (SXRF), air-dry loss (ADL), moisture (MOIS), volatile matter (VOL), fixed carbon (FIXC), high-temperature ash (HTA), low-temperature ash (LTA).

Table 11-7 - Affinity of Elements for Pure Coal
and for Mineral Matter, as Determined
from Float-Sink Data[b]

	Herrin (No. 6) Coal
Clean coal - lightest specific gravity fraction (elements in "organic combination")	Ge
	B
	Be
	Sb
	V
	Mo
	Ga
	P
	Se
	Ni
	Cr
	Co
	Cu
	Ti
	Zr
	Pb
	Mn
	As
	Cd
	Zn
Mineral matter - specific gravity greater than 1.60 (elements in "inorganic combination")	Hg

Table 11-8 – Environmental Pollution Abatement Costs ($000)

Unit	Environmental Concern	Equipment Required	Capital Cost	Operating Cost per Year
9 – Coal mine	Land reclamation	Scrapers, part of graders and draglines	17,706	3,722
11 – Coal crushing and drying	Dust control	Baghouses	270	127
23 – Oxygen plant	Noise abatement	Control system	3,781	236
24 – Fuel gas gasifier	Production of clean plant fuel	Gasifier unit	74,597	6,717
25 – Fuel gas sulfur removal	Emission of sulfur dioxide	Treatment unit	18,782	1,352
26 – Sour water treatment	Water pollutants	Treatment unit	6,225	655
27B – Sulfur plant, tail gas treatment	Emissions of gaseous sulfur compounds.	Treatment unit	5,181	365
29 – Storage	Organic vapors	Floating roofs	36	2
34 – Effluent water treatment	Water pollutants	Treatment system	5,740	444
35 – General facilities	Thermal discharges	Cooling tower	20,182	1,039
Totals			152,498	14,659